NATIONAL FUEL GAS CO
Form 10-Q
January 30, 2015

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 December 31, 2014
OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from____ to_____
Commission File Number 1-3880

NATIONAL FUEL GAS COMPANY
(Exact name of registrant as specified in its charter)

New Jersey	13-1086010
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

6363 Main Street	
Williamsville, New York	14221
(Address of principal executive offices)	(Zip Code)

(716) 857-7000
(Registrant's telephone number, including area code)

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

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

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

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

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

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

Common stock, par value $1.00 per share, outstanding at December 31, 2014: 84,264,485 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	
2014 Form 10-K	The Company's Annual Report on Form 10-K for the year ended September 30, 2014
Bbl	Barrel (of oil)
Bcf	Billion cubic feet (of natural gas)
Bcfe (or Mcfe) – represents Bcf (or Mcf) Equivalent	The total heat value (Btu) of natural gas and oil expressed as a volume of natural gas. The Company uses a conversion formula of 1 barrel of oil = 6 Mcf of natural gas.
Btu	British thermal unit; the amount of heat needed to raise the temperature of one pound of water one degree Fahrenheit
Capital expenditure	Represents additions to property, plant, and equipment, or the amount of money a company spends to buy capital assets or upgrade its existing capital assets.
Cashout revenues	A cash resolution of a gas imbalance whereby a customer pays Supply Corporation and/or Empire for gas the customer receives in excess of amounts delivered into Supply Corporation's and Empire's systems by the customer's shipper.
Degree day	A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below a reference temperature, usually 65 degrees Fahrenheit.
Derivative	A financial instrument or other contract, the terms of which include an underlying variable (a price, interest rate, index rate, exchange rate, or

	other variable) and a notional amount (number of units, barrels, cubic feet, etc.). The terms also permit for the instrument or contract to be settled net and no initial net investment is required to enter into the financial instrument or contract. Examples include futures contracts, options, no cost collars and swaps.
Development costs	Costs incurred to obtain access to proved oil and gas reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas

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.

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

• The Company has nothing to report under this item.

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

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 December 31,	
(Thousands of Dollars, Except Per Common Share Amounts)	2014	2013
INCOME		
Operating Revenues	$523,909	$550,072
Operating Expenses		
Purchased Gas	127,091	167,605
Operation and Maintenance	112,582	107,846
Property, Franchise and Other Taxes	20,929	20,926
Depreciation, Depletion and Amortization	102,747	93,114
	363,349	389,491
Operating Income	160,560	160,581
Other Income (Expense):		
Interest Income	1,258	702
Other Income	1,183	228
Interest Expense on Long-Term Debt	(22,311)	(22,885)
Other Interest Expense	(790)	(949)
Income Before Income Taxes	139,900	137,677
Income Tax Expense	55,160	55,425
Net Income Available for Common Stock	84,740	82,252
EARNINGS REINVESTED IN THE BUSINESS		
Balance at Beginning of Period	1,614,361	1,442,617
	1,699,101	1,524,869
Dividends on Common Stock	(32,442)	(31,403)
Balance at December 31	$1,666,659	$1,493,466
Earnings Per Common Share:		
Basic:		
Net Income Available for Common Stock	$1.01	$0.98
Diluted:		
Net Income Available for Common Stock	$1.00	$0.97
Weighted Average Common Shares Outstanding:		
Used in Basic Calculation	84,208,645	83,707,687
Used in Diluted Calculation	85,118,516	84,659,001
Dividends Per Common Share:		
Dividends Declared	$0.385	$0.375

See Notes to Condensed Consolidated Financial Statements

6

Table of Contents

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

	Three Months Ended December 31,	
(Thousands of Dollars)	2014	2013
Net Income Available for Common Stock	$84,740	$82,252
Other Comprehensive Income (Loss), Before Tax:		
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	(412)	2,498
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	243,829	2,778
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	(24,265)	(10,183)
Other Comprehensive Income (Loss), Before Tax	219,152	(4,907)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	(160)	925
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	102,949	1,271
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Derivative Financial Instruments in Net Income	(10,089)	(4,299)
Income Taxes – Net	92,700	(2,103)
Other Comprehensive Income (Loss)	126,452	(2,804)
Comprehensive Income	$211,192	$79,448

See Notes to Condensed Consolidated Financial Statements

Table of Contents

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	December 31, 2014	September 30, 2014
ASSETS		
Property, Plant and Equipment	$8,452,022	$8,245,791
Less - Accumulated Depreciation, Depletion and Amortization	2,598,291	2,502,700
	5,853,731	5,743,091
Current Assets		
Cash and Temporary Cash Investments	43,924	36,886
Hedging Collateral Deposits	13,468	2,734
Receivables – Net of Allowance for Uncollectible Accounts of $35,443 and $31,811, Respectively	166,887	149,735
Unbilled Revenue	69,429	25,663
Gas Stored Underground	25,555	39,422
Materials and Supplies - at average cost	28,425	27,817
Other Current Assets	68,053	54,752
Deferred Income Taxes	36,421	40,323
	452,162	377,332
Other Assets		
Recoverable Future Taxes	164,390	163,485
Unamortized Debt Expense	13,716	14,304
Other Regulatory Assets	222,609	224,436
Deferred Charges	12,524	14,212
Other Investments	87,468	86,788
Goodwill	5,476	5,476
Prepaid Post-Retirement Benefit Costs	39,520	36,512
Fair Value of Derivative Financial Instruments	293,314	72,606
Other	184	1,355
	839,201	619,174
Total Assets	$7,145,094	$6,739,597

See Notes to Condensed Consolidated Financial Statements

Table of Contents

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

	December 31, 2014	September 30, 2014
(Thousands of Dollars)		
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value		
Authorized - 200,000,000 Shares; Issued And Outstanding – 84,264,485 Shares and 84,157,220 Shares, Respectively	$84,264	$84,157
Paid in Capital	729,733	716,144
Earnings Reinvested in the Business	1,666,659	1,614,361
Accumulated Other Comprehensive Income (Loss)	122,473	(3,979)
Total Comprehensive Shareholders' Equity	2,603,129	2,410,683
Long-Term Debt, Net of Current Portion	1,649,000	1,649,000
Total Capitalization	4,252,129	4,059,683
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	172,900	85,600
Current Portion of Long-Term Debt	—	—
Accounts Payable	125,822	136,674
Amounts Payable to Customers	35,994	33,745
Dividends Payable	32,442	32,400
Interest Payable on Long-Term Debt	18,195	29,960
Customer Advances	20,436	19,005
Customer Security Deposits	16,391	15,761
Other Accruals and Current Liabilities	137,285	136,672
Fair Value of Derivative Financial Instruments	11,061	759
	570,526	490,576
Deferred Credits		
Deferred Income Taxes	1,580,626	1,456,283
Taxes Refundable to Customers	90,303	91,736
Unamortized Investment Tax Credit	1,041	1,145
Cost of Removal Regulatory Liability	175,941	173,199
Other Regulatory Liabilities	96,959	81,152
Pension and Other Post-Retirement Liabilities	126,108	134,202
Asset Retirement Obligations	118,035	117,713
Other Deferred Credits	133,426	133,908
	2,322,439	2,189,338
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$7,145,094	$6,739,597

See Notes to Condensed Consolidated Financial Statements

9

Table of Contents

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

(Thousands of Dollars)	Three Months Ended December 31, 2014	2013
OPERATING ACTIVITIES		
Net Income Available for Common Stock	$84,740	$82,252
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depreciation, Depletion and Amortization	102,747	93,114
Deferred Income Taxes	33,207	30,093
Excess Tax Benefits Associated with Stock-Based Compensation Awards	(7,667)	(3,149)
Stock-Based Compensation	3,078	2,960
Other	2,358	(2,095)
Change in:		
Hedging Collateral Deposits	(10,734)	1,094
Receivables and Unbilled Revenue	(60,947)	(92,261)
Gas Stored Underground and Materials and Supplies	9,386	17,977
Unrecovered Purchased Gas Costs	—	3,407
Other Current Assets	(5,635)	12,764
Accounts Payable	19,378	39,382
Amounts Payable to Customers	2,249	(3,944)
Customer Advances	1,431	(3,281)
Customer Security Deposits	630	(493)
Other Accruals and Current Liabilities	(6,416)	12,347
Other Assets	2,142	(6,268)
Other Liabilities	19,132	(7,205)
Net Cash Provided by Operating Activities	189,079	176,694
INVESTING ACTIVITIES		
Capital Expenditures	(244,927)	(194,920)
Other	(1,229)	3,615
Net Cash Used in Investing Activities	(246,156)	(191,305)
FINANCING ACTIVITIES		
Changes in Notes Payable to Banks and Commercial Paper	87,300	—
Excess Tax Benefits Associated with Stock-Based Compensation Awards	7,667	3,149
Dividends Paid on Common Stock	(32,400)	(31,373)
Net Proceeds from Issuance of Common Stock	1,548	1,857
Net Cash Provided by (Used) in Financing Activities	64,115	(26,367)
Net Increase (Decrease) in Cash and Temporary Cash Investments	7,038	(40,978)
Cash and Temporary Cash Investments at October 1	36,886	64,858
Cash and Temporary Cash Investments at December 31	$43,924	$23,880

Supplemental Disclosure of Cash Flow Information

Non-Cash Investing Activities:		
Non-Cash Capital Expenditures	$101,664	$52,738

See Notes to Condensed Consolidated Financial Statements

Table of Contents

National Fuel Gas Company
Notes to Condensed Consolidated Financial Statements
(Unaudited)

Note 1 - Summary of Significant Accounting Policies

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

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

Earnings for Interim Periods. The Company, in its opinion, has included all adjustments (which consist of only normally recurring adjustments, unless otherwise disclosed in this Form 10-Q) that are necessary for a fair statement of the results of operations for the reported periods. The consolidated financial statements and notes thereto, included herein, should be read in conjunction with the financial statements and notes for the years ended September 30, 2014, 2013 and 2012 that are included in the Company's 2014 Form 10-K. The consolidated financial statements for the year ended September 30, 2015 will be audited by the Company's independent registered public accounting firm after the end of the fiscal year.

The earnings for the three months ended December 31, 2014 should not be taken as a prediction of earnings for the entire fiscal year ending September 30, 2015. Most of the business of the Utility and Energy Marketing segments is seasonal in nature and is influenced by weather conditions. Due to the seasonal nature of the heating business in the Utility and Energy Marketing segments, earnings during the winter months normally represent a substantial part of the earnings that those segments are expected to achieve for the entire fiscal year. The Company’s business segments are discussed more fully in Note 7 – Business Segment Information.

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

Hedging Collateral Deposits. This is an account title for cash held in margin accounts funded by the Company to serve as collateral for hedging positions. In accordance with its accounting policy, the Company does not offset hedging collateral deposits paid or received against related derivative financial instruments liability or asset balances.

Gas Stored Underground - Current. In the Utility segment, gas stored underground – current is carried at lower of cost or market, on a LIFO method. Gas stored underground – current normally declines during the first and second quarters of the year and is replenished during the third and fourth quarters. In the Utility segment, the current cost of replacing gas withdrawn from storage is recorded in the Consolidated Statements of Income and a reserve for gas replacement is recorded in the Consolidated Balance Sheets under the caption “Other Accruals and Current Liabilities.” Such reserve, which amounted to $4.0 million at December 31, 2014, is reduced to zero by September 30 of each year as the inventory is replenished.

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

Capitalized costs include costs related to unproved properties, which are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. Such costs amounted to $162.2 million and $141.7 million at December 31, 2014 and September 30, 2014, respectively. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized.

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

Table of Contents

by applying prices of oil and gas (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The natural gas and oil prices used to calculate the full cost ceiling are based on an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period. If capitalized costs, net of accumulated depreciation, depletion and amortization and related deferred income taxes, exceed the ceiling at the end of any quarter, a permanent impairment is required to be charged to earnings in that quarter. At December 31, 2014, the ceiling exceeded the book value of the oil and gas properties by approximately $118.7 million.

Accumulated Other Comprehensive Income (Loss). The components of Accumulated Other Comprehensive Income (Loss) and changes for the three months ended December 31, 2014 and 2013, 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 December 31, 2014				
Balance at October 1, 2014	$43,659	$8,382	$(56,020)	$(3,979)
Other Comprehensive Gains and Losses Before Reclassifications	140,880	(252)	—	140,628
Amounts Reclassified From Other Comprehensive Income (Loss)	(14,176)	—	—	(14,176)
Balance at December 31, 2014	$170,363	$8,130	$(56,020)	$122,473
Three Months Ended December 31, 2013				
Balance at October 1, 2013	$30,722	$6,337	$(56,293)	$(19,234)
Other Comprehensive Gains and Losses Before Reclassifications	1,507	1,573	—	3,080
Amounts Reclassified From Other Comprehensive Income (Loss)	(5,884)	—	—	(5,884)
Balance at December 31, 2013	$26,345	$7,910	$(56,293)	$(22,038)

Reclassifications Out of Accumulated Other Comprehensive Income (Loss). The details about the reclassification adjustments out of accumulated other comprehensive income (loss) for the three months ended December 31, 2014 and 2013 are as follows (amounts in parentheses indicate debits to the income statement) (in thousands):

Details About Accumulated Other Comprehensive Income (Loss) Components	Amount of Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss)		Affected Line Item in the Statement Where Net Income is Presented
	Three Months Ended December 31,		
	2014	2013	
Gains (Losses) on Derivative Financial Instrument Cash Flow Hedges:			
Commodity Contracts	$20,036	$9,787	Operating Revenues
Commodity Contracts	4,229	396	Purchased Gas
	24,265	10,183	Total Before Income Tax

(10,089)	(4,299)	Income Tax Expense
$14,176	$5,884	Net of Tax

12

Table of Contents

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

	At December 31, 2014	At September 30, 2014
Prepayments	$15,043	$10,079
Prepaid Property and Other Taxes	15,881	13,743
Federal Income Taxes Receivable	—	8,211
Fair Values of Firm Commitments	16,006	—
Regulatory Assets	21,123	22,719
	$68,053	$54,752

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

	At December 31, 2014	At September 30, 2014
Accrued Capital Expenditures	$75,613	$80,348
Regulatory Liabilities	17,027	18,072
Reserve for Gas Replacement	4,028	—
Federal Income Taxes Payable	1,697	—
State Income Taxes Payable	7,608	5,798
Other	31,312	32,454
	$137,285	$136,672

Earnings Per Common Share. Basic earnings per common share is computed by dividing income available for common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. For purposes of determining earnings per common share, the potentially dilutive securities the Company has outstanding are stock options, SARs, restricted stock units and performance shares. The diluted weighted average shares outstanding shown on the Consolidated Statements of Income reflects the potential dilution as a result of these securities as determined using the Treasury Stock Method. Stock options, SARs, restricted stock units and performance shares that are antidilutive are excluded from the calculation of diluted earnings per common share. There were 2,461 and 272 securities excluded as being antidilutive for the quarters ended December 31, 2014 and December 31, 2013, respectively.

Stock-Based Compensation. The Company granted 107,044 performance shares during the quarter ended December 31, 2014. The weighted average fair value of such performance shares was $65.26 per share for the quarter ended December 31, 2014. Performance shares are an award constituting units denominated in common stock of the Company, the number of which may be adjusted over a performance cycle based upon the extent to which performance goals have been satisfied. Earned performance shares may be distributed in the form of shares of common stock of the Company, an equivalent value in cash or a combination of cash and shares of common stock of the Company, as determined by the Company. The performance shares do not entitle the participant to receive dividends during the vesting period.

Half of the performance shares granted during the quarter ended December 31, 2014 must meet a performance goal related to relative return on capital over the performance cycle of October 1, 2014 to September 30, 2017. The performance goal over the performance cycle is the Company's total return on capital relative to the total return on capital of other companies in a group selected by the Compensation Committee ("Report Group"). Total return on capital for a given company means the average of the Report Group companies' returns on capital for each twelve month period corresponding to each of the Company's fiscal years during the performance cycle, based on data reported for the Report Group companies in the Bloomberg database. The number of these performance shares that will vest and be paid will depend upon the Company's performance relative to the Report Group and not upon the absolute level of return achieved by the Company. The fair value of these performance shares is calculated by multiplying the expected number of shares that will be issued by the average market price of Company common stock on the date of grant reduced by the present value of forgone dividends over the vesting term of the award. The fair value is recorded as compensation expense over the vesting term of the award. The other half of the performance shares granted during the quarter ended December 31, 2014 must meet a performance goal related to relative total shareholder return over the performance cycle of October 1, 2014 to September 30, 2017. The performance goal over the performance cycle is the Company's three-year total shareholder return relative to the three-year total shareholder return of the other companies in the Report Group. Three-year shareholder return for a given company will be based on the data reported for that company (with the starting and ending stock prices over the performance cycle calculated as the average closing stock price for the prior calendar month and with dividends reinvested in that company's securities at each ex-dividend date) in the Bloomberg database. The number of these total shareholder return performance shares ("TSR performance shares") that will vest and be paid will depend upon the Company's performance relative to the Report Group and not upon the absolute level of return achieved by the Company. The fair value price at the date of grant for the TSR performance shares is determined using a Monte Carlo simulation technique, which includes a reduction in value for the present value of forgone dividends over the vesting term of the award. This price is multiplied by the number of TSR performance shares awarded, the result of which is recorded as compensation expense over the vesting term of the award.

The Company granted 88,899 non-performance based restricted stock units during the quarter ended December 31, 2014. The weighted average fair value of such non-performance based restricted stock units was $64.04 per share for the quarter ended December 31, 2014. Restricted stock units represent the right to receive shares of common stock of the Company (or the equivalent value in cash or a combination of cash and shares of common stock of the Company, as determined by the Company) at the end of a specified time period. These non-performance based restricted stock units do not entitle the participant to receive dividends during the vesting period. The accounting for non-performance based restricted stock units is the same as the accounting for restricted share awards, except that the fair value at the date of grant of the restricted stock units must be reduced by the present value of forgone dividends over the vesting term of the award.

No stock options, SARs or restricted share awards were granted by the Company during the quarter ended December 31, 2014.

New Authoritative Accounting and Financial Reporting Guidance. In May 2014, the FASB issued authoritative guidance regarding revenue recognition. The authoritative guidance provides a single, comprehensive revenue recognition model for all contracts with customers to improve comparability. The revenue standard contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2018 and early adoption is not permitted. The Company is currently evaluating the impact that adoption of this guidance will have on its consolidated financial statements and disclosures.
In June 2014, the FASB issued authoritative guidance regarding accounting for share-based payments when the terms of an award provide that a performance target could be achieved after the employee has completed the requisite service period. This authoritative guidance requires that such performance targets that affect vesting be treated as performance conditions, meaning that the performance target should not be factored in the calculation of the award at the grant date. Compensation cost should be recognized in the period in which it becomes probable that the performance target will be achieved. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2017, with early adoption permitted. The Company is currently evaluating the impact that adoption of this guidance will have on its consolidated financial statements.

Note 2 – Fair Value Measurements

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

The following table sets forth, by level within the fair value hierarchy, the Company's financial assets and liabilities (as applicable) that were accounted for at fair value on a recurring basis as of December 31, 2014 and September 30, 2014. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The fair value presentation for over the counter swaps combines gas and oil swaps because a significant number of the counterparties enter into both gas and oil swap agreements with the Company.

Table of Contents

Recurring Fair Value Measures	At fair value as of December 31, 2014				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
Assets:					
Cash Equivalents – Money Market Mutual Funds	$20,540	$—	$—	$ —	$20,540
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	6,504	—	—	(6,504)	—
Over the Counter Swaps – Gas and Oil	—	288,571	5,337	(594)	293,314
Other Investments:					
Balanced Equity Mutual Fund	36,150	—	—	—	36,150
Common Stock – Financial Services Industry	6,574	—	—	—	6,574
Other Common Stock	476	—	—	—	476
Hedging Collateral Deposits	13,468	—	—	—	13,468
Total	$83,712	$288,571	$5,337	$ (7,098)	$370,522
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	$16,812	$—	$—	$ (6,504)	$10,308
Over the Counter Swaps – Gas and Oil	—	1,347	—	(594)	753
Total	$16,812	$1,347	$—	$ (7,098)	$11,061
Total Net Assets/(Liabilities)	$66,900	$287,224	$5,337	$ —	$359,461

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

(1) Netting Adjustments represent the impact of legally-enforceable master netting arrangements that allow the Company to net gain and loss positions held with the same counterparties. The net asset or net liability for each counterparty is recorded as an asset or liability on the Company's balance sheet.

Table of Contents

Derivative Financial Instruments

At December 31, 2014 and September 30, 2014, the derivative financial instruments reported in Level 1 consist of natural gas NYMEX and ICE futures contracts used in the Company's Energy Marketing segment. Hedging collateral deposits of $13.5 million at December 31, 2014 and $2.7 million at September 30, 2014, which are associated with these futures contracts, have been reported in Level 1 as well. The derivative financial instruments reported in Level 2 at December 31, 2014 and September 30, 2014 consist of natural gas price swap agreements used in the Company's Exploration and Production and Energy Marketing segments and the majority of the crude oil price swap agreements used in the Company's Exploration and Production segment. The fair value of the Level 2 price swap agreements is based on an internal, discounted cash flow model that uses observable inputs (i.e. LIBOR based discount rates and basis differential information, if applicable, at active natural gas and crude oil trading markets). The derivative financial instruments reported in Level 3 consist of a portion of the crude oil price swap agreements used in the Company's Exploration and Production segment at December 31, 2014 and September 30, 2014. The fair value of the Level 3 crude oil price swap agreements is based on an internal, discounted cash flow model that uses both observable (i.e. LIBOR based discount rates) and unobservable inputs (i.e. basis differential information of crude oil trading markets with low trading volume).

The significant unobservable input used in the fair value measurement of a portion of the Company's over-the-counter crude oil swaps is the basis differential between Midway Sunset oil and NYMEX contracts. Significant changes in the assumed basis differential could result in a significant change in value of the derivative financial instruments. At December 31, 2014, it was assumed that Midway Sunset oil was 96.2% of NYMEX. This is based on a historical twelve month average of Midway Sunset oil sales verses NYMEX settlements. During this twelve-month period, the price of Midway Sunset oil ranged from 88.3% to 100.6% of NYMEX. If the price of Midway Sunset oil relative to NYMEX used in the fair value measurement calculation had been 10 percentage points higher, the fair value of the Level 3 crude oil price swap agreements asset would have been approximately $0.8 million lower at December 31, 2014. If the price of Midway Sunset oil relative to NYMEX used in the fair value measurement had been 10 percentage points lower, the fair value measurement of the Level 3 crude oil price swap agreements asset would have been approximately $0.8 million higher at December 31, 2014. These calculated amounts are based solely on basis differential changes and do not take into account any other changes to the fair value measurement calculation.

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 December 31, 2014, the Company determined that nonperformance risk would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty (for an asset) or the Company's (for a liability) credit default swaps rates.

The tables listed below provide reconciliations of the beginning and ending net balances for assets and liabilities measured at fair value and classified as Level 3 for the quarters ended December 31, 2014 and 2013, respectively. For the quarters ended December 31, 2014 and December 31, 2013, no transfers in or out of Level 1 or Level 2 occurred. There were no purchases or sales of derivative financial instruments during the periods presented in the tables below. All settlements of the derivative financial instruments are reflected in the Gains/Losses Realized and Included in Earnings column of the tables below (amounts in parentheses indicate credits in the derivative asset/liability accounts).

Fair Value Measurements Using Unobservable Inputs (Level 3)

(Thousands of Dollars)	Total Gains/Losses

	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	December 31, 2014
Derivative Financial Instruments[2]	$1,368	$(3,855)[1]	$7,824	$—	$5,337

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the three months ended December 31, 2014.
(2) Derivative Financial Instruments are shown on a net basis.

Table of Contents

Fair Value Measurements Using Unobservable Inputs (Level 3)

(Thousands of Dollars)		Total Gains/Losses			
	October 1, 2013	Gains/Losses Realized and Included in Earnings	Gains/Losses Unrealized and Included in Other Comprehensive Income (Loss)	Transfer In/Out of Level 3	December 31, 2013
Derivative Financial Instruments[2]	$(5,190)	$281 [1]	$3,067	$—	$(1,842)

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the three months ended December 31, 2013.

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

Note 3 – Financial Instruments

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

	December 31, 2014		September 30, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt	$1,649,000	$1,751,498	$1,649,000	$1,775,715

The fair value amounts are not intended to reflect principal amounts that the Company will ultimately be required to pay. Carrying amounts for other financial instruments recorded on the Company's Consolidated Balance Sheets approximate fair value. The fair value of long-term debt was calculated using observable inputs (U.S. Treasuries/LIBOR for the risk free component and company specific credit spread information – generally obtained from recent trade activity in the debt). As such, the Company considers the debt to be Level 2.

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

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

Other investments include cash surrender values of insurance contracts (net present value in the case of split-dollar collateral assignment arrangements) and marketable equity securities. The values of the insurance contracts amounted to $44.3 million at December 31, 2014 and $44.4 million at September 30, 2014. The fair value of the equity mutual fund was $36.1 million at December 31, 2014 and $35.3 million at September 30, 2014. The gross unrealized gain on this equity mutual fund was $8.0 million at December 31, 2014 and $8.4 million at September 30, 2014. The fair value of the stock of an insurance company was $6.6 million at both December 31, 2014 and September 30, 2014. The gross unrealized gain on this stock was $4.5 million at both December 31, 2014 and September 30, 2014. The insurance contracts and marketable equity securities are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees.

Derivative Financial Instruments. The Company uses derivative financial instruments to manage commodity price risk in the Exploration and Production segment as well as the Energy Marketing segment. The Company enters into futures contracts and over-the-counter swap agreements for natural gas and crude oil to manage the price risk associated with forecasted sales of gas and oil. These instruments are accounted for as cash flow hedges. The Company also enters into futures contracts and swaps, which are accounted for as cash flow hedges, to manage the price risk associated with forecasted gas purchases. The Company enters into futures contracts and swaps to mitigate risk associated with fixed price sales commitments, fixed price purchase commitments, and the decline in value of natural gas held in storage. These instruments are accounted for as fair value hedges.

Table of Contents

The duration of the Company's combined cash flow and fair value hedges does not typically exceed 5 years. The Exploration and Production segment holds the majority of the Company's derivative financial instruments. The derivative financial instruments held by the Energy Marketing segment are not considered to be material to the Company.

The Company has presented its net derivative assets and liabilities as "Fair Value of Derivative Financial Instruments" on its Consolidated Balance Sheets at December 31, 2014 and September 30, 2014. All of the derivative financial instruments reported on those line items relate to commodity contracts.

Cash Flow Hedges

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

As of December 31, 2014, the Company had the following commodity derivative contracts (swaps and futures contracts) outstanding:

Commodity	Units	
Natural Gas	184.0	Bcf (short positions)
Natural Gas	4.0	Bcf (long positions)
Crude Oil	2,898,000	Bbls (short positions)

As of December 31, 2014, the Company had $295.7 million ($170.4 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that $173.7 million ($100.1 million after tax) of such unrealized gains will be reclassified into the Consolidated Statement of Income within the next 12 months as the expected sales of the underlying commodities occur.

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

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Three Months Ended December 31, 2014 and 2013 (Thousands of Dollars)

Derivatives in Cash Flow Hedging Relationships	Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive Income (Loss) on the Consolidated Statement of Comprehensive Income (Loss) (Effective Portion) for the Three Months Ended December 31,	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 December 31,	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 December 31,

	2014	2013		2014	2013		2014	2013
Commodity Contracts	$240,023	$5,118	Operating Revenue	$20,036	$9,787	Operating Revenue	$1,460	$1,434
Commodity Contracts	$3,806	$(2,340)	Purchased Gas	$4,229	$396	Not Applicable	$—	$—
Total	$243,829	$2,778		$24,265	$10,183		$1,460	$1,434

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 December 31, 2014, the Company's Energy Marketing segment had fair value hedges covering approximately 17.5 Bcf (17.2 Bcf of fixed price sales commitments, 0.2 Bcf of fixed price purchase commitments and 0.1 Bcf of commitments related to the withdrawal of storage gas). For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting gain or loss on the hedged item attributable to the hedged risk completely offset each other in current earnings, as shown below.

Derivatives in Fair Value Hedging Relationships	Location of Gain or (Loss) on Derivative and Hedged Item Recognized in the Consolidated Statement of Income	Amount of Gain or (Loss) on Derivative Recognized in the Consolidated Statement of Income for the Three Months Ended December 31, 2014 (In Thousands)	Amount of Gain or (Loss) on the Hedged Item Recognized in the Consolidated Statement of Income for the Three Months Ended December 31, 2014 (In Thousands)
Commodity Contracts	Operating Revenues	$(13,338)	$13,338
Commodity Contracts	Purchased Gas	$197	$(197)
		$(13,141)	$13,141

Credit Risk

The Company may be exposed to credit risk on any of the derivative financial instruments that are in a gain position. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check, and then on a quarterly basis monitors counterparty credit exposure. The majority of the Company's counterparties are financial institutions and energy traders. The Company has over-the-counter swap positions with sixteen counterparties of which fourteen are in a net gain position. On average, the Company had $20.9 million of credit exposure per counterparty in a gain position at December 31, 2014. The maximum credit exposure per counterparty in a gain position at December 31, 2014 was $54.6 million. As of December 31, 2014, no collateral was received from the counterparties by the Company. The Company's gain position on such derivative financial instruments had not exceeded the established thresholds at which the counterparties would be required to post collateral, nor had the counterparties' credit ratings declined to levels at which the counterparties were required to post collateral.

As of December 31, 2014, twelve of the sixteen counterparties to the Company's outstanding derivative instrument contracts (specifically the over-the-counter swaps) had a common credit-risk related contingency feature. In the event the Company's credit rating increases or falls below a certain threshold (applicable debt ratings), the available credit extended to the Company would either increase or decrease. A decline in the Company's credit rating, in and of itself, would not cause the Company to be required to increase the level of its hedging collateral deposits (in the form of cash deposits, letters of credit or treasury debt instruments). If the Company's outstanding derivative instrument contracts were in a liability position (or if the liability were larger) and/or the Company's credit rating declined, then additional hedging collateral deposits may be required. At December 31, 2014, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $218.3 million according to the Company's internal model (discussed in Note 2 — Fair Value Measurements). At December 31, 2014, the fair market value of the derivative financial instrument liabilities with a credit-risk related contingency feature was $0.3 million according to the Company’s internal model (discussed in Note 2 — Fair Value Measurements). For its over-the-counter swap agreements, no hedging collateral deposits were required to be posted by the Company at December 31, 2014.

For its exchange traded futures contracts, the Company was required to post $13.5 million in hedging collateral deposits as of December 31, 2014. As these are exchange traded futures contracts, there are no specific credit-risk related contingency features. The Company posts hedging collateral based on open positions and margin requirements it has with its counterparties.

The Company’s requirement to post hedging collateral deposits 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

Table of Contents

Accruals and Current Liabilities on the Consolidated Balance Sheet. These liabilities are relieved when the broker clears the cash from the hedging collateral deposit account. This is discussed in Note 1 under Hedging Collateral Deposits.

Note 4 - Income Taxes

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

	Three Months Ended December 31,	
	2014	2013
Current Income Taxes		
Federal	$16,528	$19,707
State	5,425	5,625
Deferred Income Taxes		
Federal	26,193	23,206
State	7,014	6,887
	55,160	55,425
Deferred Investment Tax Credit	(104)	(109)
Total Income Taxes	$55,056	$55,316
Presented as Follows:		
Other Income	(104)	(109)
Income Tax Expense	55,160	55,425
Total Income Taxes	$55,056	$55,316

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

	Three Months Ended December 31,	
	2014	2013
U.S. Income Before Income Taxes	$139,796	$137,568
Income Tax Expense, Computed at U.S. Federal Statutory Rate of 35%	$48,929	$48,149
Increase (Reduction) in Taxes Resulting from:		
State Income Taxes	8,085	8,133
Miscellaneous	(1,958)	(966)
Total Income Taxes	$55,056	$55,316

On December 19, 2014, President Obama signed into law the Tax Increase Prevention Act of 2014, which did not have a significant impact on income tax expense.

Note 5 - Capitalization

Common Stock. During the three months ended December 31, 2014, the Company issued 36,000 original issue shares of common stock as a result of stock option and SARs exercises and 42,490 original issue shares of common stock for restricted stock units that vested. In addition, the Company issued 25,426 original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan and 20,523 original issue shares of common stock for the Company's 401(k) plans. The Company also issued 3,850 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 three months ended December 31, 2014. Holders of stock options, SARs, restricted share awards or restricted stock units will often tender shares of common stock to the Company for payment of option exercise prices and/or applicable withholding taxes. During the three months ended December 31, 2014, 21,024 shares of common stock were tendered to the Company for such purposes. The Company considers all shares tendered as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law.

Current Portion of Long-Term Debt. None of the Company's long-term debt at December 31, 2014 will mature within the following twelve-month period.

Note 6 - Commitments and Contingencies

Environmental Matters. The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and to comply with regulatory 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 December 31, 2014, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites will be approximately $14.2 million. The Company expects to recover such environmental clean-up costs through rate recovery over a period of approximately 13 years.

The Company's estimated liability for clean-up costs discussed above includes a $12.5 million estimated liability to remediate a former manufactured gas plant site located in New York. In February 2009, the Company received approval from the NYDEC of a Remedial Design Work Plan (RDWP) for this site. In October 2010, the Company submitted a RDWP addendum to conduct additional Preliminary Design Investigation field activities necessary to design a successful remediation. As a result of this work, the Company submitted to the NYDEC a proposal to amend the NYDEC's Record of Decision remedy for the site. In April 2013, the NYDEC approved the Company's proposed amendment. Final remedial design work for the site has begun.

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

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

Note 7 – Business Segment Information

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

The data presented in the tables below reflect financial information for the segments and reconciliations to consolidated amounts. As stated in the 2014 Form 10-K, the Company evaluates segment performance based on income before discontinued operations, extraordinary items and cumulative effects of changes in accounting (when applicable). When these items are not applicable, the Company evaluates performance based on net income. There have not been any changes in the basis of segmentation nor in the basis of measuring segment profit or loss from those used in the Company's 2014 Form 10-K. A listing of segment assets at December 31, 2014 and September 30, 2014 is shown in the tables below.

Table of Contents

Quarter Ended December 31, 2014 (Thousands)

	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$204,665	$51,745	$146	$210,073	$56,166	$522,795	$884	$230	$523,909
Intersegment Revenues	$—	$21,461	$24,428	$4,534	$206	$50,629	$—	$(50,629)	$—
Segment Profit: Net Income (Loss)	$26,720	$20,778	$11,623	$22,594	$2,826	$84,541	$(6)	$205	$84,740

(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 December 31, 2014	$3,346,609	$1,400,955	$352,464	$1,942,168	$103,985	$7,146,181	$76,960	$(78,047)	$7,145,094
At September 30, 2014	$3,100,514	$1,367,181	$326,662	$1,862,850	$76,238	$6,733,445	$86,460	$(80,308)	$6,739,597

Quarter Ended December 31, 2013 (Thousands)

	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$193,046	$51,212	$235	$230,453	$73,159	$548,105	$1,700	$267	$550,072
Intersegment Revenues	$—	$20,739	$14,350	$4,706	$255	$40,050	$—	$(40,050)	$—
Segment Profit: Net Income (Loss)	$31,097	$19,138	$6,147	$24,215	$1,604	$82,201	$675	$(624)	$82,252

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 December 31,	2014	2013	2014	2013
Service Cost	$3,012	$2,997	$673	$735
Interest Cost	10,304	10,893	4,821	5,327
Expected Return on Plan Assets	(14,904)	(14,993)	(8,522)	(9,356)
Amortization of Prior Service Cost (Credit)	46	52	(478)	(534)
Amortization of Losses	9,032	9,002	1,037	661
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) (1)	1,292	1,578	4,920	6,060
Net Periodic Benefit Cost	$8,782	$9,529	$2,451	$2,893

(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 three months ended December 31, 2014, the Company contributed $16.1 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $0.5 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2015, the Company expects its contributions to the Retirement Plan to be in the range of $2.0 million to $6.0 million. The Company is continually evaluating its future contributions in light of the provisions of the Act. In the remainder of 2015, the Company expects to contribute approximately $1.5 million to its VEBA trusts and 401(h) accounts.

Note 9 – Regulatory Matters

Following negotiations and other proceedings, on December 6, 2013, Distribution Corporation filed an agreement, also executed by the Department of Public Service and intervenors, extending existing rates through, at a minimum, September 30, 2015. Although customer rates were not changed, the parties agreed that the allowed rate of return on equity would be set, for ratemaking purposes, at 9.1%. Following conventional practice in New York, the agreement authorizes an "earnings sharing mechanism" ("ESM"). The ESM distributes earnings above the allowed rate of return as follows: from 9.5% to 10.5%, 50% would be allocated to shareholders, and 50% will be deferred for the benefit of customers; above 10.5%, 20% would be allocated to shareholders and 80% will be deferred for the benefit of customers. The agreement further authorizes, and rates reflect, an increase in Distribution Corporation's pipeline replacement spending by $8.2 million per year. The agreement contains other terms and conditions of service that are customary for settlement agreements recently approved by the NYPSC. A $7.5 million refund provision was passed back to ratepayers during 2014 after the NYPSC approved the settlement agreement without modification in an order issued on May 8, 2014.

23

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

For the quarter ended December 31, 2014 compared to the quarter ended December 31, 2013, the Company experienced an increase in earnings of $2.5 million. The earnings increase for the quarter ended December 31, 2014 is primarily due to higher earnings in the Gathering segment, Pipeline and Storage segment and Energy Marketing segment, partly offset by lower earnings in the Exploration and Production segment and Utility segment. For further discussion of the Company’s earnings, refer to the Results of Operations section below.

The Company’s natural gas reserve base continues to develop its reserves in the Marcellus Shale, a Middle Devonian-age geological shale formation that is present nearly a mile or more below the surface in the Appalachian region of the United States, including much of Pennsylvania and southern New York. The Company controls the natural gas interests associated with approximately 780,000 net acres within the Marcellus Shale area, with a majority of the interests held in fee, carrying no royalty and no lease expirations. Natural gas proved developed and undeveloped reserves in the Appalachian region increased from 1,239 Bcf at September 30, 2013 to 1,624 Bcf at September 30, 2014. The Company has spent significant amounts of capital in this region related to the development of such reserves. For the three months ended December 31, 2014, the Company’s Exploration and Production segment had capital expenditures of $134.1 million in the Appalachian region, of which $125.8 million was spent towards the development of the Marcellus Shale. The amount spent towards the development of the Marcellus Shale represented approximately 60% of the Company’s capital expenditures for the three months ended December 31, 2014. With the potential for continued low natural gas and crude oil prices, the Company is reducing its fiscal 2015 estimated capital expenditures in the Exploration and Production segment from approximately $650 million to approximately $550 million. The Company also intends to curtail production due to low natural gas and crude oil prices. Forecasted production in the Exploration and Production segment for fiscal 2015 is expected to be in the range of 155 to 190 Bcfe, down from the previous range of 180 to 220 Bcfe.

To facilitate the flow of natural gas from the Marcellus Shale, the Company continues to expand its gathering and pipeline infrastructure in the Gathering segment and the Pipeline and Storage segment. For the three months ended December 31, 2014, the Gathering segment had capital expenditures of $15.0 million. The Pipeline and Storage segment's capital expenditures for the three months ended December 31, 2014 were $16.0 million. The amount spent towards the development of gathering and pipeline infrastructure during the three months ended December 31, 2014 represented approximately 15% of the Company's capital expenditures. With the potential for continued low natural gas prices in the Exploration and Production segment, the Company is reducing its fiscal 2015 estimated capital expenditures in the Gathering segment from approximately $175 million to approximately $150 million.

From a capital resources perspective, the Company has largely been able to meet its capital expenditure needs by using cash from operations as well as both short and long-term debt. It is expected that the Company will use short-term and long-term debt as necessary during fiscal 2015 to help meet its capital expenditure needs. On December 5, 2014, the Company entered into an Amended and Restated Credit Agreement that replaced the Company’s existing $750.0 million committed credit facility with a substantially similar committed credit facility totaling $750.0 million that extends through December 5, 2019. The previous committed credit facility extended through January 6, 2017.

The well completion technology referred to as hydraulic fracturing used in conjunction with horizontal drilling continues to be debated. In Pennsylvania, where the Company is focusing its Marcellus Shale development efforts, the permitting and regulatory processes seem to strike a balance between the environmental concerns associated with hydraulic fracturing and the benefits of increased natural gas production. The potential for increased state or federal regulation of hydraulic fracturing could impact future costs of drilling in the Marcellus Shale and lead to operational delays or restrictions. There is also the risk that drilling could be prohibited on certain acreage that is prospective for the Marcellus Shale. Please refer to the Risk Factors section of the Company's 2014 Form 10-K for further discussion.

CRITICAL ACCOUNTING ESTIMATES

For a complete discussion of critical accounting estimates, refer to "Critical Accounting Estimates" in Item 7 of the Company's 2014 Form 10-K. There have been no material changes to that disclosure other than as set forth below. The information presented below updates and should be read in conjunction with the critical accounting estimates in that Form 10-K.

Oil and Gas Exploration and Development Costs. The Company, in its Exploration and Production segment, follows the full cost method of accounting for determining the book value of its oil and natural gas properties. In accordance with this methodology, the Company is required to perform a quarterly ceiling test. Under the ceiling test, the present value of future revenues from the Company's oil and gas reserves based on an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period (the "ceiling") is compared with the book value of the Company's oil and gas properties at the balance sheet date. If the book value of the oil and gas properties exceeds the ceiling, a non-cash impairment charge must be recorded to reduce the book value of the oil and gas properties to the calculated ceiling. At December 31, 2014, the ceiling exceeded the book value of the oil and gas properties by approximately $118.7 million. The 12-month average of the first day of the month price for crude oil for each month during the twelve months ended December 31, 2014, based on posted Midway Sunset prices, was $92.14 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 December 31, 2014, based on the quoted Henry Hub spot price for natural gas, was $4.35 per MMBtu. (Note – Because actual pricing of the Company's various producing properties varies depending on their location and hedging, the actual various prices received for such production is utilized to calculate the ceiling, rather than the Midway Sunset and Henry Hub prices, which are only indicative of 12-month average prices for the twelve months ended December 31, 2014.) If natural gas average prices used in the ceiling test calculation at December 31, 2014 had been $1 per MMBtu lower, the book value of the Company's oil and gas properties would have exceeded the ceiling by approximately $363.5 million, which would have resulted in an impairment charge. If crude oil average prices used in the ceiling test calculation at December 31, 2014 had been $5 per Bbl lower, the ceiling would have exceeded the book value of the Company's oil and gas properties by approximately $77.3 million. If both natural gas and crude oil average prices used in the ceiling test calculation at December 31, 2014 were lower by $1 per MMBtu and $5 per Bbl, respectively, the book value of the Company's oil and gas properties would have exceeded the ceiling by approximately $405.0 million, which would have resulted in an impairment charge. These calculated amounts are based solely on price changes and do not take into account any other changes to the ceiling test calculation. Looking ahead, the first day of the month Midway Sunset price for crude oil in January 2015 was $47.07 per Bbl. The first day of the month Henry Hub spot price for natural gas in January 2015 was $3.00 per MMBtu. Given these prices and the potential that they will stay at this level, the Company could have ceiling test impairments in 2015. For a more complete discussion of the full cost method of accounting, refer to "Oil and Gas Exploration and Development Costs" under "Critical Accounting Estimates" in Item 7 of the Company's 2014 Form 10-K.

RESULTS OF OPERATIONS

Earnings

The Company's earnings were $84.7 million for the quarter ended December 31, 2014 compared with earnings of $82.3 million for the quarter ended December 31, 2013. The increase in earnings is primarily a result of higher earnings in the Pipeline and Storage segment, Gathering segment, Energy Marketing segment and the Corporate category. Lower earnings in the Utility segment, Exploration and Production segment and the All Other category partially offset these increases.

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

Table of Contents

Earnings (Loss) by Segment

	Three Months Ended December 31,		
(Thousands)	2014	2013	Increase (Decrease)
Exploration and Production	$26,720	$31,097	$(4,377)
Pipeline and Storage	20,778	19,138	1,640
Gathering	11,623	6,147	5,476
Utility	22,594	24,215	(1,621)
Energy Marketing	2,826	1,604	1,222
Total Reportable Segments	84,541	82,201	2,340
All Other	(6)	675	(681)
Corporate	205	(624)	829
Total Consolidated	$84,740	$82,252	$2,488

Exploration and Production

Exploration and Production Operating Revenues

	Three Months Ended December 31,		
(Thousands)	2014	2013	Increase (Decrease)
Gas (after Hedging)	$141,657	$121,616	$20,041
Oil (after Hedging)	60,166	67,254	(7,088)
Gas Processing Plant	1,058	1,316	(258)
Other	1,784	2,860	(1,076)
	$204,665	$193,046	$11,619

Production Volumes

	Three Months Ended December 31,		
	2014	2013	Increase (Decrease)
Gas Production (MMcf)			
Appalachia	42,798	32,052	10,746
West Coast	773	786	(13)
Total Production	43,571	32,838	10,733
Oil Production (Mbbl)			
Appalachia	9	9	—
West Coast	762	706	56
Total Production	771	715	56

Table of Contents

Average Prices

	Three Months Ended December 31, 2014	2013	Increase (Decrease)
Average Gas Price/Mcf			
Appalachia	$2.95	$3.28	$(0.33)
West Coast	$5.61	$5.93	$(0.32)
Weighted Average	$3.00	$3.35	$(0.35)
Weighted Average After Hedging	$3.25	$3.70	$(0.45)
Average Oil Price/Bbl			
Appalachia	$75.56	$96.03	$(20.47)
West Coast	$66.86	$97.45	$(30.59)
Weighted Average	$66.96	$97.43	$(30.47)
Weighted Average After Hedging	$78.09	$94.00	$(15.91)

2014 Compared with 2013

Operating revenues for the Exploration and Production segment increased $11.6 million for the quarter ended December 31, 2014 as compared with the quarter ended December 31, 2013. Gas production revenue after hedging increased $20.0 million due to production increases in the Appalachian division. The increase in Appalachian production was primarily due to increased development within the Marcellus Shale formation, primarily in Lycoming County, Pennsylvania. This was partially offset by a $0.45 per Mcf decrease in the weighted average price of gas after hedging. Oil production revenue after hedging decreased $7.1 million due to a $15.91 per Bbl decrease in the weighted average price of oil after hedging. This was partially offset by an increase in production. The increase in crude oil production was largely due to increased development in the East Coalinga and South Midway Sunset fields in California. The decrease in other revenue ($1.1 million) was largely due to settlement proceeds received in 2014 related to former insurance policies ($1.9 million) that did not recur in the current period.

The Exploration and Production segment's earnings for the quarter ended December 31, 2014 were $26.7 million, a decrease of $4.4 million when compared with earnings of $31.1 million for the quarter ended December 31, 2013. The main drivers of the decrease were the earnings impact of lower natural gas prices after hedging ($12.8 million), lower crude oil prices after hedging ($8.0 million), higher depletion expense ($5.8 million), higher production costs ($7.6 million) and a decrease in other revenue ($0.7 million) as discussed above. The increase in depletion expense is primarily due to increased Appalachian natural gas production (primarily in the Marcellus Shale formation). The increase in production costs was largely attributable to higher transportation costs. These decreases were partially offset by the impact of higher natural gas production ($25.8 million), higher crude oil production ($3.4 million) and lower income taxes ($1.4 million). The decrease in income taxes was largely due to the favorable partial settlement of a prior period research and development credit coupled with the impact of lower state income tax expense.

Table of Contents

Pipeline and Storage

Pipeline and Storage Operating Revenues

(Thousands)	Three Months Ended December 31, 2014	2013	Increase (Decrease)
Firm Transportation	$54,193	$52,146	$2,047
Interruptible Transportation	747	586	161
	54,940	52,732	2,208
Firm Storage Service	17,489	17,465	24
Interruptible Storage Service	1	1	—
Other	776	1,753	(977)
	$73,206	$71,951	$1,255

Pipeline and Storage Throughput

(MMcf)	Three Months Ended December 31, 2014	2013	Increase (Decrease)
Firm Transportation	186,322	191,656	(5,334)
Interruptible Transportation	2,102	1,322	780
	188,424	192,978	(4,554)

2014 Compared with 2013

Operating revenues for the Pipeline and Storage segment increased $1.3 million for the quarter ended December 31, 2014 as compared with the quarter ended December 31, 2013. The increase was primarily due to an increase in transportation revenues of $2.2 million, partially offset by a decrease in other revenues of $1.0 million. The increase in transportation revenues was largely due to demand charges for transportation service from Supply Corporation’s Mercer Expansion Project, which was placed in service in November 2014. Also contributing to the increase in transportation revenues was additional non-expansion revenue as a result of both new short-term and long-term contracts for transportation service from various Open Seasons Supply Corporation has held. Partially offsetting these increases was a decrease in cashout revenues of $1.0 million (reported as a part of other revenue in the table above). Cashout revenues are completely offset by purchased gas expense and as a result have no impact on earnings.

Transportation volume for the quarter ended December 31, 2014 decreased by 4.6 Bcf from the prior year’s quarter due to warmer weather, but there was little impact on revenues due to Supply Corporation and Empire’s straight fixed-variable rate design.

The Pipeline and Storage segment’s earnings for the quarter ended December 31, 2014 were $20.8 million, an increase of $1.7 million when compared with earnings of $19.1 million for the quarter ended December 31, 2013. The increase in earnings is primarily due to the earnings impact of higher transportation revenues of $1.4 million, as discussed above, combined with an increase in the allowance for funds used during construction (equity component) of $0.8 million. The increase in the allowance for funds used during construction is mainly due to Supply Corporation’s Mercer Expansion Project, which remained under construction in the beginning of the current quarter. These earnings increases were partially offset by an increase in operating expenses ($0.6 million) which primarily reflects higher benefit costs and an increase in the reserve for preliminary project costs.

28

Table of Contents

Gathering

Gathering Operating Revenues

(Thousands)	Three Months Ended December 31, 2014	2013	Increase (Decrease)
Gathering	$24,428	$14,377	$10,051
Processing and Other Revenues	146	208	(62)
	$24,574	$14,585	$9,989

Gathering Volume

	Three Months Ended December 31, 2014	2013	Increase (Decrease)
Gathered Volume - (MMcf)	44,872	31,014	13,858

2014 Compared with 2013

Operating revenues for the Gathering segment increased $10.0 million for the quarter ended December 31, 2014 as compared with the quarter ended December 31, 2013. This increase was largely due to an increase in gathering revenues driven by a 13.9 Bcf increase in gathered volume combined with higher gathering rates. The overall increase in gathered volume was largely due to an 11.0 Bcf increase in gathered volume on Midstream Corporation’s Trout Run Gathering System (Trout Run) and a 4.3 Bcf increase in gathered volume on Midstream Corporation’s Clermont Gathering System (Clermont). Most of the increase in gathered volume is attributable to an increase in Seneca's Marcellus Shale production, primarily in Lycoming County, Pennsylvania. These increases in gathered volume were partially offset by a 1.5 Bcf decrease in gathering volume on Midstream Corporation's Covington Gathering System (Covington) due to a decline in Seneca's Marcellus Shale production in the Covington area of Tioga County, Pennsylvania.

The Gathering segment’s earnings for the quarter ended December 31, 2014 were $11.6 million, an increase of $5.5 million when compared with earnings of $6.1 million for the quarter ended December 31, 2013. The increase in earnings is mainly due to the earnings impact of higher gathering revenues ($6.5 million). This earnings increase was partially offset by higher income tax expense ($0.7 million) and higher operating expenses ($0.4 million). The significant growth of Trout Run and Clermont is primarily responsible for the revenue and operating expense variations. The increase in income tax expense was largely due to higher state income taxes.

Table of Contents

Utility

Utility Operating Revenues

(Thousands)	Three Months Ended December 31, 2014	2013	Increase (Decrease)
Retail Sales Revenues:			
Residential	$146,686	$162,075	$(15,389)
Commercial	18,297	20,548	(2,251)
Industrial	751	864	(113)
	165,734	183,487	(17,753)
Transportation	39,888	40,356	(468)
Off-System Sales	5,924	7,921	(1,997)
Other	3,061	3,395	(334)
	$214,607	$235,159	$(20,552)

Utility Throughput

(MMcf)	Three Months Ended December 31, 2014	2013	Increase (Decrease)
Retail Sales:			
Residential	16,467	17,008	(541)
Commercial	2,284	2,360	(76)
Industrial	89	91	(2)
	18,840	19,459	(619)
Transportation	20,949	21,190	(241)
Off-System Sales	1,669	1,978	(309)
	41,458	42,627	(1,169)

Degree Days

Three Months Ended December 31,	Normal	2014	2013	Percent Colder (Warmer) Than Normal[1]	Prior Year[1]
Buffalo	2,253	2,136	2,290	(5.2)%	(6.7)%
Erie	2,044	1,990	2,110	(2.6)%	(5.7)%

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

2014 Compared with 2013

Operating revenues for the Utility segment decreased $20.6 million for the quarter ended December 31, 2014 as compared with the quarter ended December 31, 2013. This increase largely resulted from a $17.8 million decrease in retail gas sales revenues, a $2.0 million decrease in off-system sales (due to lower volume), and a $0.5 million decrease in transportation revenues. The decrease in retail gas revenues is due to a 0.6 Bcf decrease in throughput (largely due to warmer weather compared to the prior period) and a decrease in the cost of gas sold. The decrease in off-system sales is due to market conditions that have continued to reduce the amount of gas available for off-system sales and the price at which that gas could be sold. Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal. The decrease in transportation revenues was due to a 0.2 Bcf decrease in throughput, largely due to warmer weather compared to the prior period.

Table of Contents

The Utility segment's earnings for the quarter ended December 31, 2014 were $22.6 million, a decrease of $1.6 million when compared with earnings of $24.2 million for the quarter ended December 31, 2013. This decrease largely resulted from the earnings impact of a $1.2 million increase in operating expenses (due to operating costs associated with the planned replacement of the Utility segment's legacy mainframe systems).

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 December 31, 2014, the WNC increased earnings by approximately $0.2 million, as the weather was warmer than normal. For the quarter ended December 31, 2013, the WNC reduced earnings by approximately $0.2 million, as the weather was colder than normal.

Energy Marketing

Energy Marketing Operating Revenues

(Thousands)	Three Months Ended December 31, 2014	2013	Increase (Decrease)
Natural Gas (after Hedging)	$56,330	$73,373	$(17,043)
Other	42	41	1
	$56,372	$73,414	$(17,042)

Energy Marketing Volume

	Three Months Ended December 31, 2014	2013	Increase (Decrease)
Natural Gas – (MMcf)	12,589	16,008	(3,419)

2014 Compared with 2013

Operating revenues for the Energy Marketing segment decreased $17.0 million for the quarter ended December 31, 2014 as compared with the quarter ended December 31, 2013. The decrease reflects an $8.5 million reduction in revenues associated with the impact of recording unbilled revenue for the first time in the quarter ended December 31, 2013. Prior to that quarter, Energy Marketing segment revenues and related purchased gas costs had been recorded when billed, resulting in a one-month lag. In moving from the one-month lag, revenues and related gas costs for the quarter ended December 31, 2013 reflected four months of activity whereas the revenue and related gas costs for the quarter ended December 31, 2014 reflect three months of activity. The impact of this change had an immaterial impact on margin for the quarter ended December 31, 2014. The remaining $8.5 million reduction in operating revenues for the quarter ended December 31, 2014 compared with the quarter ended December 31, 2013 reflects a decline in gas sales revenue due to a decrease in volume sold to retail customers as a result of warmer weather and a lower average price of natural gas period over period.

The Energy Marketing segment's earnings for the quarter ended December 31, 2014 were $2.8 million, an increase of $1.2 million when compared with earnings of $1.6 million for the quarter ended December 31, 2013. This increase in earnings was largely attributable to higher margin of $1.3 million. The increase in margin largely reflects improved average margin per Mcf, partially offset by the margin impact associated with unbilled revenue that is discussed above.

Corporate and All Other

2014 Compared with 2013

Corporate and All Other operations recorded earnings of $0.2 million for the quarter ended December 31, 2014, which were relatively flat when compared with the earnings of $0.1 million for the quarter ended December 31, 2013.

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

Interest on long-term debt decreased $0.6 million for the quarter ended December 31, 2014 as compared with the quarter ended December 31, 2013. The decrease in interest on long-term debt was due to an increase in capitalized interest (mostly in Midstream Corporation) for the quarter ended December 31, 2014 compared to the quarter ended December 31, 2013.

CAPITAL RESOURCES AND LIQUIDITY

The Company's primary source of cash during the three-month period ended December 31, 2014 consisted of cash provided by operating activities and net proceeds from short-term borrowings. The Company's primary sources of cash during the three-month period ended December 31, 2013 consisted of cash provided by operating activities. These sources of cash were supplemented by net proceeds from the issuance of common stock for both the three months ended December 31, 2014 and December 31, 2013, 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, 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 $189.1 million for the three months ended December 31, 2014, an increase of $12.4 million compared with $176.7 million provided by operating activities for the three months ended December 31, 2013. The increase in cash provided by operating activities reflects higher cash provided by operating activities in the Utility segment and Gathering segment. The increase is primarily offset by a decrease in cash provided by operating activities in the Energy Marketing segment. The increase in the Utility segment is primarily due to the timing of gas cost recovery and the timing of receivable collections. The increase in the Gathering segment is primarily due to an increase in Seneca's Marcellus Shale production. The decrease in the Energy Marketing segment is due to an increase in hedging collateral deposits on futures contracts.

Table of Contents

Investing Cash Flow

Expenditures for Long-Lived Assets

The Company’s expenditures for long-lived assets totaled $210.0 million during the three months ended December 31, 2014 and $166.5 million for the three months ended December 31, 2013. These amounts include accounts payable and accrued liabilities related to capital expenditures and will differ from capital expenditures shown on the Consolidated Statement of Cash Flows. They are included in subsequent Consolidated Statement of Cash Flows when they are paid. The table below presents these expenditures:

Total Expenditures for Long-Lived Assets

Three Months Ended December 31, (Millions)	2014		2013		Increase(Decrease)
Exploration and Production:					
Capital Expenditures	$157.7	(1)	$111.3	(2)	$ 46.4
Pipeline and Storage:					
Capital Expenditures	16.0	(1)	9.9	(2)	6.1
Gathering:					
Capital Expenditures	15.0	(1)	23.5	(2)	(8.5)
Utility:					
Capital Expenditures	21.2	(1)	21.7	(2)	(0.5)
All Other:					
Capital Expenditures	0.1	(1)	0.1	(2)	—
	$210.0		$166.5		$ 43.5

(1) At December 31, 2014, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $82.3 million, $3.0 million, $11.0 million and $5.4 million, respectively, of accounts payable and accrued liabilities related to capital expenditures. At September 30, 2014, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $80.1 million, $28.1 million, $20.1 million and $8.3 million, respectively, of accounts payable and accrued liabilities related to capital expenditures.

(2) At December 31, 2013, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $38.4 million, $0.6 million, $8.8 million and $4.9 million, respectively, of accounts payable and accrued liabilities related to capital expenditures. At September 30, 2013, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $58.5 million, $5.6 million, $6.7 million and $10.3 million, respectively, of accounts payable and accrued liabilities related to capital expenditures.

Exploration and Production

The Exploration and Production segment capital expenditures for the three months ended December 31, 2014 were primarily well drilling and completion expenditures and included approximately $134.1 million for the Appalachian region (including $125.8 million in the Marcellus Shale area) and $23.6 million for the West Coast region. These amounts included approximately $60.4 million spent to develop proved undeveloped reserves.

The Exploration and Production segment capital expenditures for the three months ended December 31, 2013 were primarily well drilling and completion expenditures and included approximately $105.0 million for the Appalachian region (including $99.1 million in the Marcellus Shale area) and $6.3 million for the West Coast region. These amounts included approximately $41.0 million spent to develop proved undeveloped reserves.

Pipeline and Storage

The Pipeline and Storage capital expenditures for the three months ended December 31, 2014 were mainly for expenditures related to Supply Corporation's Westside Expansion and Modernization Project ($6.2 million), Supply Corporation's Mercer Expansion Project ($2.6 million) and Empire and Supply Corporation's Tuscarora Lateral Project ($1.1 million). In addition, the Pipeline and Storage segment capital expenditures for the three months ended December 31, 2014 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 three months ended December 31, 2013 were mainly related to additions, improvements, and replacements to this segment's transmission and gas storage systems and also include $1.5 million spent on the Mercer Expansion Project.

In light of the growing demand for pipeline capacity to move natural gas from new wells being drilled in Appalachia — specifically in the Marcellus and Utica Shale producing areas — Supply Corporation and Empire are actively pursuing several expansion projects and paying for preliminary survey and investigation costs, which are initially recorded as Deferred Charges on the Consolidated Balance Sheet. An offsetting reserve is established as those preliminary survey and investigation costs are incurred, which reduces the Deferred Charges balance and increases Operation and Maintenance Expense on the Consolidated Statement of Income. The Company reviews all projects on a quarterly basis, and if it is determined that it is highly probable that the project will be built, the reserve is reversed. This reversal reduces Operation and Maintenance Expense and reestablishes the original balance in Deferred Charges. After the reversal of the reserve, the amounts remain in Deferred Charges until such time as capital expenditures for the project have been incurred and activities that are necessary to get the construction project ready for its intended use are in progress. At that point, the balance is transferred from Deferred Charges to Construction Work in Progress, a component of Property, Plant and Equipment on the Consolidated Balance Sheet. As of December 31, 2014, the total amount reserved for the Pipeline and Storage segment's preliminary survey and investigation costs was $7.4 million.

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

In 2011, Supply Corporation concluded an Open Season to increase its capability to move gas north on its Line N system and deliver gas to a new interconnection with Tennessee Gas Pipeline ("TGP") at Mercer, Pennsylvania, a pooling point recently established at Tennessee's Station 219 ("Mercer Expansion Project"). Supply Corporation has executed a precedent agreement with Range Resources for 105,000 Dth per day, all of the project capacity, for service which began November 1, 2014. The cost estimate is $33.9 million, of which $29.9 million is for expansion and $4.0 million is for system modernization. Supply Corporation constructed the required 3,550 horsepower of compression at Mercer, and replaced 2.08 miles of 24" pipeline, both under its FERC blanket certificate authorization. As of December 31, 2014, approximately $30.3 million has been spent on the Mercer Expansion Project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at December 31, 2014.

On January 18, 2013, Supply Corporation concluded an Open Season to further increase its capacity to move gas north and south on its Line N system to Texas Eastern Transmission, LP ("TETCO") at Holbrook and TGP at Mercer ("Westside Expansion and Modernization Project"). Supply Corporation executed two precedent agreements for all 175,000 Dth per day of project capacity, for service expected to begin in November 2015. The Westside Expansion and Modernization Project facilities include the replacement of approximately 23.3 miles of 20" pipe with 24" pipe and the addition of 3,550 horsepower of compression at Mercer. The cost estimate is $86.0 million, of which $44.9 million is related to expansion and the remainder is for replacement. Supply Corporation filed the FERC 7(c) application in early February 2014 and anticipates a FERC certificate in the second quarter of fiscal 2015. As of December 31, 2014, approximately $11.0 million has been capitalized as Construction Work in Progress for the Westside Expansion and Modernization Project.

Supply Corporation and TGP have jointly developed a project that will combine expansions on both pipeline systems, providing a seamless transportation path from TGP's 300 Line in the Marcellus fairway to the TransCanada Pipeline delivery point at Niagara. Supply Corporation has offered 140,000 Dth per day of capacity on its system to TGP under a lease, from its Ellisburg Station for redelivery to TGP in East Eden, New York ("Northern Access 2015"). The project will provide Seneca Resources, TGP's anchor shipper, with an outlet to premium Dawn indexed markets in Canada, for their Clermont Area Marcellus production. The Northern Access 2015 project involves the construction of a new 15,400 horsepower compressor station in Hinsdale, New York and a 7,700 horsepower addition to its compressor station in Concord, New York, for service expected to commence in November 2015. Supply Corporation and TGP have executed a precedent agreement incorporating the lease agreement, and both companies filed their respective FERC 7(c) applications in early March 2014 and anticipate a FERC certificate in the second quarter of fiscal 2015. The preliminary cost estimate for the Northern Access 2015 project is $66 million. As of December 31, 2014, approximately $11.4 million has been capitalized as Construction Work in Progress for the Northern Access 2015 project.

Supply Corporation and Empire have been working with Seneca Resources to develop a project which would move significant prospective Marcellus production from its Western Development Area at Clermont to an interconnection on Empire with TransCanada Pipeline at Chippawa ("Northern Access 2016"). Similar to the Northern Access 2015 project, this project would provide an outlet to premium Dawn indexed markets in Canada in late 2016. The Northern Access 2016 project involves the construction of approximately 99.3 miles of 24" pipeline and 26,000 horsepower of compression on the two systems. The preliminary cost estimate for the Northern Access 2016 project is $449 million. Seneca Resources executed anchor shipper

Table of Contents

agreements for 350,000 Dth per day of firm transportation delivery capacity to Chippawa on this project, and has been awarded the capacity by Supply Corporation and Empire following the close of their respective Open Seasons on June 26, 2014. On July 24, 2014, Supply Corporation and Empire initiated the FERC NEPA Pre-filing process on this project. As of December 31, 2014, approximately $5.1 million has been spent to study the Northern Access 2016 project. The Company has determined it is highly probable that the project will be built. Accordingly, previous reserves have been reversed and the project costs have been reestablished as a Deferred Charge on the Consolidated Balance Sheet.

On August 12, 2013, Empire concluded an Open Season, offering for the first time no-notice transportation and storage services to new and existing shippers on the Empire pipeline system. Rochester Gas & Electric ("RG&E"), Empire's largest LDC connected market, has executed a precedent agreement to convert all 172,500 Dth per day of its standard firm transportation services to no-notice service, including 3.3 Bcf of no-notice storage service. The new services will provide RG&E with a superior flexible delivery service with daily and seasonal load balancing capabilities and greater access to Marcellus supplies. In addition, Empire has executed a precedent agreement with New York State Electric and Gas for 14,816 Dth per day of transportation capacity and a third agreement with Distribution Corporation for the remaining 34,500 Dth per day of project capacity, providing both LDCs with increased access to Marcellus supplies. The project would require Empire to construct a 17.2 mile, 12" and 16" pipeline and an interconnection between Empire's pipeline system and Supply Corporation's system at Tuscarora, New York. It would also require Empire to modify its Oakfield compressor station and require Supply Corporation to construct approximately 1,380 horsepower of compression at its Tuscarora compressor station ("Tuscarora Lateral Project"). Supply Corporation concluded an Open Season and has awarded to Empire the necessary storage services under a lease agreement. Empire and Supply Corporation began the FERC pre-filing process on April 12, 2013, and both companies filed their FERC 7(c) applications in March 2014. The preliminary cost estimate for the Tuscarora Lateral Project is $58.5 million. As of December 31, 2014, approximately $2.8 million has been capitalized as Construction Work in Progress for the Tuscarora Lateral Project.

Empire is developing an expansion of its system that would allow for the transportation of approximately 250,000 Dth per day of additional Marcellus supplies from Millennium Pipeline at Corning or from new interconnections in Tioga County, Pennsylvania, to TransCanada Pipeline and the TGP 200 Line ("Central Tioga County Extension"). In addition, the connection to Supply Corporation afforded by the Tuscarora Lateral Project could allow those Marcellus supplies to be sourced from other parts of Supply Corporation. Such a configuration would likely involve facility investments on the Supply Corporation system as well. The preliminary cost estimate for the Central Tioga County Extension is $114 million to $150 million depending on requested receipt points. As of December 31, 2014, approximately $0.3 million has been spent to study the Central Tioga County Extension project, all of which has been included in preliminary survey and investigation charges and has been fully reserved for at December 31, 2014.

Gathering

The majority of the Gathering segment capital expenditures for the three months ended December 31, 2014 were for the construction of Midstream Corporation's Clermont Gathering System, as discussed below. The majority of the Gathering segment capital expenditures for the three months ended December 31, 2013 were for the construction of Midstream Corporation's Clermont Gathering System and to build compressor stations on Midstream Corporation's Trout Run Gathering System.

NFG Midstream Trout Run, LLC, a wholly owned subsidiary of Midstream Corporation, continues to develop its Trout Run Gathering System in Lycoming County, Pennsylvania. The Trout Run Gathering System was initially placed in service in May 2012. The current system consists of approximately 40 miles of backbone and in-field gathering pipelines and two compressor stations. As of December 31, 2014, the Company has spent approximately

$161.3 million in costs related to this project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at December 31, 2014.

NFG Midstream Clermont, LLC, a wholly owned subsidiary of Midstream Corporation, is building an extensive gathering system with compression in the Pennsylvania counties of McKean, Elk and Cameron. The preliminary cost estimate for the continued buildout is anticipated to be in the range of $250 million to $450 million. As of December 31, 2014, approximately $114.9 million has been spent on the Clermont Gathering System, including approximately $15.7 million spent during the three months ended December 31, 2014, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at December 31, 2014.

Utility

The majority of the Utility capital expenditures for the three months ended December 31, 2014 and December 31, 2013 were made for replacement of mains and main extensions, as well as for the replacement of service lines. The capital expenditures for the three months ended December 31, 2014 and December 31, 2013 also include $4.1 million and $4.9 million, respectively,

Table of Contents

related to the replacement of the Utility segment's customer information system, which is scheduled to be placed in service in the summer of 2015.

Project Funding

The Company has been financing the Pipeline and Storage segment and Gathering segment projects mentioned above, as well as the Exploration and Production segment capital expenditures, with cash from operations and both short and long-term borrowings. Going forward, while the Company expects to use cash from operations as the first means of financing these projects, it is expected that the Company will issue short-term and long-term debt as necessary during fiscal 2015 to help meet its capital expenditures needs. The level of such short-term and long-term borrowings will depend upon the amounts of cash provided by operations, which, in turn, will likely be impacted by natural gas and crude oil prices combined with production from existing wells.

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

Financing Cash Flow

Consolidated short-term debt increased $87.3 million when comparing the balance sheet at December 31, 2014 to the balance sheet at September 30, 2014. The maximum amount of short-term debt outstanding during the three months ended December 31, 2014 was $203.9 million. The Company continues to consider short-term debt (consisting of short-term notes payable to banks and commercial paper) an important source of cash for temporarily financing capital expenditures and investments in corporations and/or partnerships, gas-in-storage inventory, unrecovered purchased gas costs, margin calls on derivative financial instruments, exploration and development expenditures, other working capital needs and repayment of long-term debt. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt. At December 31, 2014, the Company had outstanding commercial paper of $172.9 million. The Company did not have any outstanding short-term notes payable to banks at December 31, 2014. On December 5, 2014, the Company entered into an Amended and Restated Credit Agreement with a syndicate of 14 banks. The agreement replaced the Company's previous $750.0 million committed credit facility with a substantially similar facility totaling $750.0 million. The new facility extends through December 5, 2019. The Company also has a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under the uncommitted lines of credit are made at competitive market rates. The uncommitted credit lines are revocable at the option of the financial institutions and are reviewed on an annual basis. The Company anticipates that its uncommitted lines of credit generally will be renewed or substantially replaced by similar lines.

The total amount available to be issued under the Company's commercial paper program is $300.0 million. At December 31, 2014, the commercial paper program was backed by the Amended and Restated $750.0 million syndicated committed credit facility. Under the new committed credit facility, the Company agreed that its debt to capitalization ratio would not exceed .65 at the last day of any fiscal quarter through December 5, 2019. At December 31, 2014, the Company's debt to capitalization ratio (as calculated under the facility) was .41. The constraints specified in the committed credit facility would have permitted an additional $3.01 billion in short-term and/or long-term debt to be outstanding (further limited by the indenture covenants discussed below) before the Company's debt to capitalization ratio exceeded .65.

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

The Company’s Amended and Restated $750.0 million committed credit facility, like the one it replaced, also contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the committed credit facility. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $40.0 million or more or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $40.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of December 31, 2014, the Company did not have any debt outstanding under the committed credit facility.

Table of Contents

Under the Company’s existing indenture covenants, at December 31, 2014, the Company would have been permitted to issue up to a maximum of $2.22 billion in additional long-term unsecured indebtedness at then current market interest rates in addition to being able to issue new indebtedness to replace maturing debt. The Company’s present liquidity position is believed to be adequate to satisfy known demands. However, if the Company were to experience a significant loss in the future (for example, as a result of an impairment of oil and gas properties), it is possible, depending on factors including the magnitude of the loss, that these indenture covenants would restrict the Company’s ability to issue additional long-term unsecured indebtedness for a period of up to nine calendar months, beginning with the fourth calendar month following the loss. This would not at any time preclude the Company from issuing new indebtedness to replace maturing debt. Please refer to the Critical Accounting Estimates section above for a sensitivity analysis concerning commodity price changes and their impact on the ceiling test.
The Company’s 1974 indenture pursuant to which $99.0 million (or 6.0%) of the Company’s long-term debt (as of December 31, 2014) was issued, contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

The Company’s embedded cost of long-term debt was 5.58% at both December 31, 2014 and December 31, 2013.

None of the Company’s long-term debt at December 31, 2014 and 2013 had a maturity date within the following twelve-month period.

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

OFF-BALANCE SHEET ARRANGEMENTS

The Company has entered into certain off-balance sheet financing arrangements. These financing arrangements are primarily operating leases. The Company’s consolidated subsidiaries have operating leases, the majority of which are with the Exploration and Production segment and Corporate operations, having a remaining lease commitment of approximately $60.4 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 three months ended December 31, 2014, the Company contributed $16.1 million to its Retirement Plan and $0.5 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2015, the Company expects its contributions to the Retirement Plan to be in the range of $2.0 million to $6.0 million. In the remainder of 2015, the Company expects to contribute $1.5 million to its VEBA trusts and 401(h) accounts.

Market Risk Sensitive Instruments

On July 21, 2010, the Dodd-Frank Act was signed into law. The Dodd-Frank Act includes provisions related to the swaps and over-the-counter derivatives markets. Certain provisions of the Dodd-Frank Act related to derivatives became effective July 16, 2011, but other provisions related to derivatives have or will become effective as federal agencies (including the CFTC, various banking regulators and the SEC) adopt rules to implement the law. Among other things, the Dodd-Frank Act (1) regulates certain participants in the swaps markets, including new entities defined as “swap dealers” and “major swap participants,” (2) requires clearing and exchange-trading of certain swaps that the CFTC determines must be cleared, (3) requires reporting and recordkeeping of swaps, and (4) enhances the CFTC's enforcement authority, including the authority to establish position limits on derivatives and increases penalties for violations of the Commodity Exchange Act. For purposes of the Dodd-Frank Act, under rules adopted by the SEC and/or CFTC, the Company believes that it qualifies as a non-financial end user of derivatives, that is, as a non-financial entity that uses derivatives to hedge or mitigate commercial risk. Nevertheless, other rules that are being developed could have a significant impact on the Company. For example, the CFTC has imposed numerous registration, swaps documentation, business conduct, reporting, and recordkeeping requirements on swap dealers and major swap participants, which frequently are counterparties to the Company's derivative hedging transactions. Similarly, the CFTC and various banking regulators have proposed rules that would require swap dealers and major swap participants subject to their jurisdiction to comply with certain obligations relating to capitalization and the collection of initial and variation margin from certain counterparties, although the recent proposals do not mandate the collection of margin from counterparties that qualify as non-financial end users, such as the Company. Regardless of the final capital and margin rules, concern remains that swap dealers and major swap participants will pass along their increased costs stemming from the final and proposed rules through higher transaction costs and prices or other direct or indirect costs. In addition, while the Company expects to be exempt from the Dodd-Frank Act's requirement that certain swaps be cleared and traded on exchanges or swap execution facilities, the cost of entering into a non-exchange cleared swap that is available as an exchange cleared swap may be greater. The Dodd-Frank Act may also increase costs for derivative recordkeeping, reporting, documentation, position limit compliance, and other compliance; cause parties to materially alter the terms of derivative contracts; cause parties to restructure certain derivative contracts; reduce the availability of derivatives to protect against risks that the Company encounters or to optimize assets; reduce the Company's ability to monetize or restructure existing derivative contracts; and increase the Company's exposure to less creditworthy counterparties, all of which could increase the Company's business costs. The Company continues to monitor these developments but cannot predict the impact the Dodd-Frank Act may ultimately have on its operations.

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

The Company uses the crude oil swaps classified as Level 3 to hedge against the risk of declining commodity prices and not as speculative investments. Gains or losses related to these Level 3 derivative net assets (including any reduction for credit risk) are deferred until the hedged commodity transaction occurs in accordance with the provisions of the existing guidance for derivative instruments and hedging activities. The Level 3 derivative net assets amount to $5.3 million at December 31, 2014 and represent 1.5% of the Total Net Assets shown in Part I, Item 1 at Note 2 – Fair Value Measurements at December 31, 2014.

The increase in the net fair value asset of the Level 3 positions from October 1, 2014 to December 31, 2014, as shown in Part I, Item 1 at Note 2, was attributable to a decrease in the commodity price of crude oil (at the aforementioned sales location) relative to the swap prices during that period. The Company believes that these fair values reasonably represent the amounts that the Company would realize upon settlement based on commodity prices that were present at December 31, 2014.

The accounting rules for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At December 31, 2014, the Company determined that nonperformance risk would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty (for an asset) or the Company’s (for a liability) credit default swaps rates.

For a complete discussion of market risk sensitive instruments, refer to "Market Risk Sensitive Instruments" in Item 7 of the Company's 2014 Form 10-K. There have been no subsequent material changes to the Company’s exposure to market risk sensitive instruments.

Rate and Regulatory Matters

Utility Operation

Delivery rates for both the New York and Pennsylvania divisions are regulated by the states’ respective public utility commissions and typically are changed only when approved through a procedure known as a “rate case.” Although neither division has a rate case on file, see below for a description of other rate proceedings affecting the New York division. In both jurisdictions,

Table of Contents

delivery rates do not reflect the recovery of purchased gas costs. Prudently-incurred gas costs are recovered through operation of automatic adjustment clauses, and are collected primarily through a separately-stated “supply charge” on the customer bill.

New York Jurisdiction

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

Following negotiations and other proceedings, on December 6, 2013, Distribution Corporation filed an agreement, also executed by the Department of Public Service and intervenors, extending existing rates through, at a minimum, September 30, 2015. Although customer rates were not changed, the parties agreed that the allowed rate of return on equity would be set, for ratemaking purposes, at 9.1%. Following conventional practice in New York, the agreement authorizes an “earnings sharing mechanism” (“ESM”). The ESM distributes earnings above the allowed rate of return as follows: from 9.5% to 10.5%, 50% would be allocated to shareholders, and 50% will be deferred for the benefit of customers; above 10.5%, 20% to shareholders and 80% will be deferred for the benefit of customers. The agreement further authorizes, and rates reflect, an increase in Distribution Corporation’s pipeline replacement spending by $8.2 million per year. The agreement contains other terms and conditions of service that are customary for settlement agreements recently approved by the NYPSC. A $7.5 million ($4.9 million after-tax) refund provision was passed back to ratepayers during 2014 after the NYPSC approved the settlement agreement without modification in an order issued on May 8, 2014.

Pennsylvania Jurisdiction

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

Pipeline and Storage

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

Empire also does not have a rate case currently on file with the FERC, but is not subject to any requirement to make any future general rate filing. Empire is also not barred from filing a general rate case at any time.

Environmental Matters

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and comply with regulatory requirements.
For further discussion of the Company's environmental exposures, refer to Item 1 at Note 6 — Commitments and Contingencies under the heading “Environmental Matters.”

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussion or implementation. In the United States, these efforts include legislative proposals and EPA regulations at the federal level, actions at the state level, and private party litigation related to greenhouse gas emissions. While the U.S. Congress has from time to time considered legislation aimed at reducing emissions of greenhouse gases, Congress has not yet passed any federal climate change legislation and we cannot predict when or if Congress will pass such legislation and in what form. In the absence of such legislation, the EPA is regulating greenhouse gas emissions pursuant to the authority granted to it by the federal Clean Air Act. For example, in April 2012, the EPA adopted rules which restrict emissions associated with oil and natural gas drilling. Compliance with these rules will not materially change the Company's ongoing emissions–limiting technologies and practices, and is not expected to have a significant impact on the Company. In addition, the U.S. Congress has from time to time considered bills that would establish a cap-and-trade program to reduce emissions of greenhouse gases. Legislation or regulation that restricts carbon emissions could increase the Company's cost of environmental compliance by requiring the Company to install new equipment to reduce emissions from larger facilities and/or purchase emission allowances. International, federal, state

Table of Contents

or regional climate change and greenhouse gas measures could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard to existing and new facilities, or impose additional monitoring and reporting requirements. Climate change and greenhouse gas initiatives, and incentives to conserve energy or use alternative energy sources, could also reduce demand for oil and natural gas. But legislation or regulation that sets a price on or otherwise restricts carbon emissions could also benefit the Company by increasing demand for natural gas, because substantially fewer carbon emissions per Btu of heat generated are associated with the use of natural gas than with certain alternate fuels such as coal and oil. The effect (material or not) on the Company of any new legislative or regulatory measures will depend on the particular provisions that are ultimately adopted.

New Authoritative Accounting and Financial Reporting Guidance

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

Safe Harbor for Forward-Looking Statements

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

1. Factors affecting the Company’s ability to successfully identify, drill for and produce economically viable natural gas and oil reserves, including among others geology, lease availability, title disputes, weather conditions, shortages, delays or unavailability of equipment and services required in drilling operations, insufficient gathering, processing and transportation capacity, the need to obtain governmental approvals and permits, and compliance with environmental laws and regulations;
2. The cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company;
3. Changes in laws, regulations or judicial interpretations to which the Company is subject, including those involving derivatives, taxes, safety, employment, climate change, other environmental matters, real property, and exploration and production activities such as hydraulic fracturing;

4. Governmental/regulatory actions, initiatives and proceedings, including those involving rate cases (which address, among other things, target rates of return, rate design and retained natural gas), environmental/safety requirements, affiliate relationships, industry structure, and franchise renewal;
5. Changes in the price of natural gas or oil;
6. Changes in price differential between similar quantities of natural gas or oil at different geographic locations, and the effect of such changes on commodity production, revenues and demand for pipeline transportation capacity to or from such locations;
7. Other changes in price differentials between similar quantities of natural gas or oil having different quality, heating value, hydrocarbon mix or delivery date;

Table of Contents

8. Impairments under the SEC’s full cost ceiling test for natural gas and oil reserves;
9. Uncertainty of oil and gas reserve estimates;
10. Significant differences between the Company’s projected and actual production levels for natural gas or oil;
11. Delays or changes in costs or plans with respect to Company projects or related projects of other companies, including difficulties or delays in obtaining necessary governmental approvals, permits or orders or in obtaining the cooperation of interconnecting facility operators;
12. Changes in demographic patterns and weather conditions;
13. Changes in the availability, price or accounting treatment of derivative financial instruments;
14. Financial and economic conditions, including the availability of credit, and occurrences affecting the Company’s ability to obtain financing on acceptable terms for working capital, capital expenditures and other investments, including any downgrades in the Company’s credit ratings and changes in interest rates and other capital market conditions;
15. Changes in economic conditions, including global, national or regional recessions, and their effect on the demand for, and customers’ ability to pay for, the Company’s products and services;
16. The creditworthiness or performance of the Company’s key suppliers, customers and counterparties;
17. Economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities, acts of war, cyber attacks or pest infestation;
18. Significant differences between the Company’s projected and actual capital expenditures and operating expenses;
19. Changes in laws, actuarial assumptions, the interest rate environment and the return on plan/trust assets related to the Company’s pension and other post-retirement benefits, which can affect future funding obligations and costs and plan liabilities;
20. Increasing health care costs and the resulting effect on health insurance premiums and on the obligation to provide other post-retirement benefits; or
21. Increasing costs of insurance, changes in coverage and the ability to obtain insurance.

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC’s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to the company’s management, including its principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. The Company's management, including the Chief Executive Officer and Principal Financial Officer, evaluated 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 December 31, 2014.

Changes in Internal Control Over Financial Reporting

There were no changes in the Company’s internal control over financial reporting that occurred during the quarter ended December 31, 2014 that have materially affected, or are reasonably likely to materially affect, the Company’s internal control over financial reporting.

Table of Contents

Part II. Other Information

Item 1. Legal Proceedings

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

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

Item 1A. Risk Factors

The risk factors in Item 1A of the Company's 2014 Form 10-K have not materially changed.

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

On October 1, 2014, the Company issued a total of 3,850 unregistered shares of Company common stock to the seven non-employee directors of the Company then serving on the Board of Directors of the Company, 550 shares to each such director. All of these unregistered shares were issued under the Company's 2009 Non-Employee Director Equity Compensation Plan as partial consideration for such directors' services during the quarter ended December 31, 2014. These transactions were exempt from registration under Section 4(a)(2) of the Securities Act of 1933, as transactions not involving a public offering.

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)
Oct. 1 - 31, 2014	357	$69.91	—	6,971,019
Nov. 1 - 30, 2014	—	N/A	—	6,971,019
Dec. 1 - 31, 2014	20,667	$69.03	—	6,971,019
Total	21,024	$69.05	—	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 December 31, 2014, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program.

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

Table of Contents

Item 6. Exhibits

Exhibit Number	Description of Exhibit
10.1	Amended and Restated Credit Agreement, dated as of December 5, 2014, among the Company, the Lenders Party Thereto, and JP Morgan Chase Bank, National Association, as Administrative Agent.
10.2	Form of Award Notice for Return on Capital Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan.
10.3	Form of Award Notice for Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan.
12	Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the Twelve Months Ended December 31, 2014 and the Fiscal Years Ended September 30, 2011 through 2014.
31.1	Written statements of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act.
31.2	Written statements of Principal Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act.
32••	Certification furnished pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99	National Fuel Gas Company Consolidated Statements of Income for the Twelve Months Ended December 31, 2014 and 2013.
101	Interactive data files submitted pursuant to Regulation S-T: (i) the Consolidated Statements of Income and Earnings Reinvested in the Business for the three months ended December 31, 2014 and 2013, (ii) the Consolidated Statements of Comprehensive Income for the three months ended December 31, 2014 and 2013, (iii) the Consolidated Balance Sheets at December 31, 2014 and September 30, 2014, (iv) the Consolidated Statements of Cash Flows for the three months ended December 31, 2014 and 2013 and (v) the Notes to Condensed Consolidated Financial Statements.

•• 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: January 30, 2015