NATIONAL FUEL GAS CO
Form 10-Q
February 02, 2018
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d)
OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended December 31, 2017
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, smaller reporting company, or an emerging growth company. See the definitions of “large accelerated filer,” “accelerated filer” “smaller reporting company,” and “emerging growth 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	¨
		Emerging Growth Company	¨

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ¨

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 January 31, 2018: 85,801,778 shares.

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GLOSSARY OF TERMS

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

National Fuel Gas Companies	
Company	The Registrant, the Registrant and its subsidiaries or the Registrant's subsidiaries as appropriate in the context of the disclosure
Distribution Corporation	National Fuel Gas Distribution Corporation
Empire	Empire Pipeline, Inc.
Midstream Corporation	National Fuel Gas Midstream Corporation
National Fuel	National Fuel Gas Company
NFR	National Fuel Resources, Inc.
Registrant	National Fuel Gas Company
Seneca	Seneca Resources Corporation
Supply Corporation	National Fuel Gas Supply Corporation

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

Other	
2017 Form 10-K	The Company's Annual Report on Form 10-K for the year ended September 30, 2017
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 (e.g. a marketer) pays for gas the customer receives in excess of amounts delivered into pipeline/storage or distribution systems by the customer's shipper.
Degree day	A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below a reference temperature, usually 65 degrees Fahrenheit.
Derivative	A financial instrument or other contract, the terms of which include an underlying variable (a price, interest rate, index rate, exchange rate, or other variable) and a notional amount (number of units, barrels, cubic feet, etc.). The terms also permit for the instrument or contract to be settled net and no initial net investment is required to enter into the financial instrument or contract. Examples include futures contracts, forward contracts, options, no cost collars and

	swaps.
Development costs	Costs incurred to obtain access to proved oil and gas reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act.

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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.
Exploratory well	A well drilled in unproven or semi-proven territory for the purpose of ascertaining the presence underground of a commercial hydrocarbon deposit.
FERC 7(c) application	An application to the FERC under Section 7(c) of the federal Natural Gas Act for authority to construct, operate (and provide services through) facilities to transport or store natural gas in interstate commerce.
Firm transportation and/or storage	The transportation and/or storage service that a supplier of such service is obligated by contract to provide and for which the customer is obligated to pay whether or not the service is utilized.
GAAP	Accounting principles generally accepted in the United States of America
Goodwill	An intangible asset representing the difference between the fair value of a company and the price at which a company is purchased.
Hedging	A method of minimizing the impact of price, interest rate, and/or foreign currency exchange rate changes, often times through the use of derivative financial instruments.
Hub	Location where pipelines intersect enabling the trading, transportation, storage, exchange, lending and borrowing of natural gas.
ICE	Intercontinental Exchange. An exchange which maintains a futures market for crude oil and natural gas.
Interruptible transportation and/or storage	The transportation and/or storage service that, in accordance with contractual arrangements, can be interrupted by the supplier of such service, and for which the customer does not pay unless utilized.
LDC	Local distribution company
LIBOR	London Interbank Offered Rate
LIFO	Last-in, first-out
Marcellus Shale	A Middle Devonian-age geological shale formation that is present nearly a mile or more below the surface in the Appalachian region of the United States, including much of Pennsylvania and southern New York.
Mbbl	Thousand barrels (of oil)
Mcf	Thousand cubic feet (of natural gas)
MD&A	Management’s Discussion and Analysis of Financial Condition and Results of Operations
MDth	Thousand decatherms (of natural gas)
MMBtu	Million British thermal units (heating value of one decatherm of natural gas)
MMcf	Million cubic feet (of natural gas)
NEPA	National Environmental Policy Act of 1969, as amended
NGA	The Natural Gas Act of 1938, as amended; the federal law regulating interstate natural gas pipeline and storage companies, among other things, codified beginning at 15 U.S.C. Section 717.
NYMEX	New York Mercantile Exchange. An exchange which maintains a futures market for crude oil and natural gas.
Open Season	A bidding procedure used by pipelines to allocate firm transportation or storage capacity among prospective shippers, in which all bids submitted during a defined time period are evaluated as if they had been submitted simultaneously.

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Precedent Agreement	An agreement between a pipeline company and a potential customer to sign a service agreement after specified events (called “conditions precedent”) happen, usually within a specified time.
Proved developed reserves	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved undeveloped (PUD) reserves	Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required to make these reserves productive.
Reserves	The unproduced but recoverable oil and/or gas in place in a formation which has been proven by production.
Revenue decoupling mechanism	A rate mechanism which adjusts customer rates to render a utility financially indifferent to throughput decreases resulting from conservation.
S&P	Standard & Poor’s Rating Service
SAR	Stock appreciation right
Service agreement	The binding agreement by which the pipeline company agrees to provide service and the shipper agrees to pay for the service.
Stock acquisitions	Investments in corporations
Utica Shale	A Middle Ordovician-age geological formation lying several thousand feet below the Marcellus Shale in the Appalachian region of the United States, including much of Ohio, Pennsylvania, West Virginia and southern New York.
VEBA	Voluntary Employees’ Beneficiary Association
WNC	Weather normalization clause; a clause in utility rates which adjusts customer rates to allow a utility to recover its normal operating costs calculated at normal temperatures. If temperatures during the measured period are warmer than normal, customer rates are adjusted upward in order to recover projected operating costs. If temperatures during the measured period are colder than normal, customer rates are adjusted downward so that only the projected operating costs will be recovered.

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• The Company has nothing to report under this item.

All references to a certain year in this report are to the Company’s fiscal year ended September 30 of that year, unless otherwise noted.

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Part I. Financial Information

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

	Three Months Ended December 31,	
(Thousands of Dollars, Except Per Common Share Amounts)	2017	2016
INCOME		
Operating Revenues:		
Utility and Energy Marketing Revenues	$225,725	$207,780
Exploration and Production and Other Revenues	140,450	161,694
Pipeline and Storage and Gathering Revenues	53,480	53,026
	419,655	422,500
Operating Expenses:		
Purchased Gas	94,034	70,243
Operation and Maintenance:		
Utility and Energy Marketing	51,369	50,422
Exploration and Production and Other	35,542	30,461
Pipeline and Storage and Gathering	20,037	22,660
Property, Franchise and Other Taxes	20,848	20,379
Depreciation, Depletion and Amortization	55,830	56,196
	277,660	250,361
Operating Income	141,995	172,139
Other Income (Expense):		
Interest Income	2,249	1,600
Other Income	1,722	1,614
Interest Expense on Long-Term Debt	(28,087)	(29,103)
Other Interest Expense	(502)	(910)
Income Before Income Taxes	117,377	145,340
Income Tax Expense (Benefit)	(81,277)	56,432
Net Income Available for Common Stock	198,654	88,908
EARNINGS REINVESTED IN THE BUSINESS		
Balance at Beginning of Period	851,669	676,361
	1,050,323	765,269
Dividends on Common Stock	(35,590)	(34,544)
Cumulative Effect of Adoption of Authoritative Guidance for Stock-Based Compensation	—	31,916
Balance at December 31	$1,014,733	$762,641
Earnings Per Common Share:		
Basic:		
Net Income Available for Common Stock	$2.32	$1.04

Diluted:		
Net Income Available for Common Stock	$2.30	$1.04
Weighted Average Common Shares Outstanding:		
Used in Basic Calculation	85,630,296	85,189,851
Used in Diluted Calculation	86,325,537	85,797,989
Dividends Per Common Share:		
Dividends Declared	$0.415	$0.405

See Notes to Condensed Consolidated Financial Statements

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

	Three Months Ended December 31,	
(Thousands of Dollars)	2017	2016
Net Income Available for Common Stock	$198,654	$88,908
Other Comprehensive Income (Loss), Before Tax:		
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	(44)	(883)
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(5,499)	(52,501)
Reclassification Adjustment for Realized (Gains) Losses on Securities Available for Sale in Net Income	(430)	(741)
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	(12,548)	(30,717)
Other Comprehensive Loss, Before Tax	(18,521)	(84,842)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	(65)	(344)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(2,305)	(22,052)
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Securities Available for Sale in Net Income	(158)	(273)
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Derivative Financial Instruments in Net Income	(5,197)	(12,954)
Income Taxes – Net	(7,725)	(35,623)
Other Comprehensive Loss	(10,796)	(49,219)
Comprehensive Income	$187,858	$39,689

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	December 31, 2017	September 30, 2017
ASSETS		
Property, Plant and Equipment	$ 10,023,252	$ 9,945,560
Less - Accumulated Depreciation, Depletion and Amortization	5,294,211	5,271,486
	4,729,041	4,674,074
Current Assets		
Cash and Temporary Cash Investments	166,289	555,530
Hedging Collateral Deposits	4,465	1,741
Receivables – Net of Allowance for Uncollectible Accounts of $24,511 and $22,526, Respectively	161,029	112,383
Unbilled Revenue	74,790	22,883
Gas Stored Underground	24,139	35,689
Materials and Supplies - at average cost	35,139	33,926
Unrecovered Purchased Gas Costs	7,787	4,623
Other Current Assets	47,914	51,505
	521,552	818,280
Other Assets		
Recoverable Future Taxes	116,792	181,363
Unamortized Debt Expense	8,148	1,159
Other Regulatory Assets	174,577	174,433
Deferred Charges	34,063	30,047
Other Investments	123,368	125,265
Goodwill	5,476	5,476
Prepaid Post-Retirement Benefit Costs	57,054	56,370
Fair Value of Derivative Financial Instruments	21,107	36,111
Other	754	742
	541,339	610,966
Total Assets	$ 5,791,932	$ 6,103,320

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

	December 31, 2017	September 30, 2017
(Thousands of Dollars)		
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value		
Authorized - 200,000,000 Shares; Issued And Outstanding – 85,760,846 Shares and 85,543,125 Shares, Respectively	$ 85,761	$ 85,543
Paid in Capital	800,348	796,646
Earnings Reinvested in the Business	1,014,733	851,669
Accumulated Other Comprehensive Loss	(40,919)	(30,123)
Total Comprehensive Shareholders' Equity	1,859,923	1,703,735
Long-Term Debt, Net of Current Portion and Unamortized Discount and Debt Issuance Costs	2,084,465	2,083,681
Total Capitalization	3,944,388	3,787,416
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	—	—
Current Portion of Long-Term Debt	—	300,000
Accounts Payable	132,409	126,443
Amounts Payable to Customers	251	—
Dividends Payable	35,590	35,500
Interest Payable on Long-Term Debt	27,962	35,031
Customer Advances	18,398	15,701
Customer Security Deposits	22,503	20,372
Other Accruals and Current Liabilities	121,596	111,889
Fair Value of Derivative Financial Instruments	6,579	1,103
	365,288	646,039
Deferred Credits		
Deferred Income Taxes	453,285	891,287
Taxes Refundable to Customers	366,768	95,739
Cost of Removal Regulatory Liability	205,554	204,630
Other Regulatory Liabilities	118,551	113,716
Pension and Other Post-Retirement Liabilities	125,055	149,079
Asset Retirement Obligations	106,516	106,395
Other Deferred Credits	106,527	109,019
	1,482,256	1,669,865
Commitments and Contingencies (Note 6)	—	—
Total Capitalization and Liabilities	$ 5,791,932	$ 6,103,320

See Notes to Condensed Consolidated Financial Statements

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

(Thousands of Dollars)	Three Months Ended December 31, 2017	2016
OPERATING ACTIVITIES		
Net Income Available for Common Stock	$198,654	$88,908
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depreciation, Depletion and Amortization	55,830	56,196
Deferred Income Taxes	(94,676)	44,852
Stock-Based Compensation	3,905	2,482
Other	3,678	3,607
Change in:		
Hedging Collateral Deposits	(2,724)	1,484
Receivables and Unbilled Revenue	(83,357)	(67,395)
Gas Stored Underground and Materials and Supplies	10,337	10,597
Unrecovered Purchased Gas Costs	(3,164)	(1,257)
Other Current Assets	3,591	9,576
Accounts Payable	13,173	18,805
Amounts Payable to Customers	251	(16,306)
Customer Advances	2,697	(983)
Customer Security Deposits	2,131	673
Other Accruals and Current Liabilities	11,532	5,919
Other Assets	(5,275)	(8,389)
Other Liabilities	(21,775)	(4,122)
Net Cash Provided by Operating Activities	94,808	144,647
INVESTING ACTIVITIES		
Capital Expenditures	(142,613)	(106,053)
Net Proceeds from Sale of Oil and Gas Producing Properties	—	5,759
Other	2,612	(4,297)
Net Cash Used in Investing Activities	(140,001)	(104,591)
FINANCING ACTIVITIES		
Reduction of Long-Term Debt	(307,047)	—
Dividends Paid on Common Stock	(35,500)	(34,473)
Net Proceeds from Issuance (Repurchase) of Common Stock	(1,501)	938
Net Cash Used in Financing Activities	(344,048)	(33,535)
Net Increase (Decrease) in Cash and Temporary Cash Investments	(389,241)	6,521
Cash and Temporary Cash Investments at October 1	555,530	129,972
Cash and Temporary Cash Investments at December 31	$166,289	$136,493
Supplemental Disclosure of Cash Flow Information		
Non-Cash Investing Activities:		
Non-Cash Capital Expenditures	$56,116	$48,965
Receivable from Sale of Oil and Gas Producing Properties	$17,310	$20,795

See Notes to Condensed Consolidated Financial Statements

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

Note 1 - Summary of Significant Accounting Policies

Principles of Consolidation. The Company consolidates all entities in which it has a controlling financial interest. All significant intercompany balances and transactions are eliminated. The Company uses proportionate consolidation when accounting for drilling arrangements related to oil and gas producing properties accounted for under the full cost method of accounting.

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

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, 2017, 2016 and 2015 that are included in the Company's 2017 Form 10-K. The consolidated financial statements for the year ended September 30, 2018 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, 2017 should not be taken as a prediction of earnings for the entire fiscal year ending September 30, 2018. 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 Statements of Cash Flows. For purposes of the Consolidated Statements of Cash Flows, the Company considers all highly liquid debt instruments purchased with a maturity of generally three months or less to be cash equivalents.

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

Gas Stored Underground. In the Utility segment, gas stored underground is carried at lower of cost or net realizable value, on a LIFO method. Gas stored underground normally declines during the first and second quarters of the year and is replenished during the third and fourth quarters. In the Utility segment, the current cost of replacing gas withdrawn from storage is recorded in the Consolidated Statements of Income and a reserve for gas replacement is recorded in the Consolidated Balance Sheets under the caption “Other Accruals and Current Liabilities.” Such reserve, which amounted to $1.7 million at December 31, 2017, 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 $77.1 million and $80.9 million at December 31, 2017 and September 30, 2017, respectively. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized.

Capitalized costs are subject to the SEC full cost ceiling test. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying prices of oil and gas (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The natural gas and oil prices used to calculate the full cost ceiling are based on an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period. If capitalized costs, net of accumulated depreciation, depletion and amortization and related deferred income taxes, exceed the ceiling at the end of any quarter, a permanent impairment is required to be charged to earnings in that quarter. At December 31, 2017, the ceiling exceeded the book value of the oil and gas properties by approximately $334.6 million. In adjusting estimated future cash flows for hedging under the ceiling test at December 31, 2017, estimated future net cash flows were increased by $18.0 million.

On December 1, 2015, Seneca and IOG - CRV Marcellus, LLC (IOG), an affiliate of IOG Capital, LP, and funds managed by affiliates of Fortress Investment Group, LLC, executed a joint development agreement that allows IOG to participate in the development of certain oil and gas interests owned by Seneca in Elk, McKean and Cameron Counties, Pennsylvania. On June 13, 2016, Seneca and IOG executed an extension of the joint development agreement. Under the terms of the extended agreement, Seneca and IOG will jointly participate in a program to develop up to 75 Marcellus wells, with Seneca serving as program operator. IOG will hold an 80% working interest in all of the joint development wells. In total, IOG is expected to fund approximately $305 million for its 80% working interest in the 75 joint development wells. Of this amount, IOG has funded $267.1 million as of December 31, 2017, which includes $163.9 million of cash ($137.3 million in fiscal 2016 and $26.6 million in fiscal 2017) shown as Net Proceeds from Sale of Oil and Gas Producing Properties on the Consolidated Statements of Cash Flows for fiscal 2016 and fiscal 2017. Such proceeds from sale represent funding received from IOG for costs previously incurred by Seneca to develop a portion of the 75 joint development wells. A receivable of $17.3 million has been recorded at December 31, 2017 in recognition of additional IOG funding that is due to Seneca for costs incurred by Seneca to develop a portion of the 75 joint development wells. This receivable has been shown as a Non-Cash Investing Activity on the Consolidated Statement of Cash Flows for the quarter ended December 31, 2017. As the fee-owner of the property’s mineral rights, Seneca currently retains a 7.5% royalty interest and the remaining 20% working interest (26% net revenue interest) in 56 of the joint development wells. In the remaining 19 wells, Seneca retains a 20% working and net revenue interest. Seneca’s working interest under the agreement will increase to 85% after IOG achieves a 15% internal rate of return.

Accumulated Other Comprehensive Loss. The components of Accumulated Other Comprehensive Loss and changes for the three months ended December 31, 2017 and 2016, 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, 2017				
Balance at October 1, 2017	$ 20,801	$ 7,562	$ (58,486)	$(30,123)
Other Comprehensive Gains and Losses Before Reclassifications	(3,194)	21	—	(3,173)
Amounts Reclassified From Other Comprehensive Loss	(7,351)	(272)	—	(7,623)
Balance at December 31, 2017	$ 10,256	$ 7,311	$ (58,486)	$(40,919)
Three Months Ended December 31, 2016				
Balance at October 1, 2016	$ 64,782	$ 6,054	$ (76,476)	$(5,640)
Other Comprehensive Gains and Losses Before Reclassifications	(30,449)	(539)	—	(30,988)
Amounts Reclassified From Other Comprehensive Loss	(17,763)	(468)	—	(18,231)

Balance at December 31, 2016	$ 16,570	$ 5,047	$ (76,476)	$(54,859)

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Reclassifications Out of Accumulated Other Comprehensive Loss. The details about the reclassification adjustments out of accumulated other comprehensive loss for the three months ended December 31, 2017 and 2016 are as follows (amounts in parentheses indicate debits to the income statement) (in thousands):

Details About Accumulated Other Comprehensive Loss Components	Amount of Gain or (Loss) Reclassified from Accumulated Other Comprehensive Loss Three Months Ended December 31, 2017	2016	Affected Line Item in the Statement Where Net Income is Presented
Gains (Losses) on Derivative Financial Instrument Cash Flow Hedges:			
Commodity Contracts	$12,842	$31,320	Operating Revenues
Commodity Contracts	196	(460)	Purchased Gas
Foreign Currency Contracts	(490)	(143)	Operation and Maintenance Expense
Gains (Losses) on Securities Available for Sale	430	741	Other Income
	12,978	31,458	Total Before Income Tax
	(5,355)	(13,227)	Income Tax Expense
	$7,623	$18,231	Net of Tax

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

	At December 31, 2017	At September 30, 2017
Prepayments	$ 7,259	$ 10,927
Prepaid Property and Other Taxes	14,972	13,974
State Income Taxes Receivable	9,164	9,689
Fair Values of Firm Commitments	3,218	1,031
Regulatory Assets	13,301	15,884
	$ 47,914	$ 51,505

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

	At December 31, 2017	At September 30, 2017
Accrued Capital Expenditures	$ 28,488	$ 37,382
Regulatory Liabilities	38,920	34,059
Reserve for Gas Replacement	1,739	—
Federal Income Taxes Payable	8,688	1,775
2017 Tax Reform Act Refund	6,000	—
Other	37,761	38,673

$ 121,596	$ 111,889

Earnings Per Common Share. Basic earnings per common share is computed by dividing income or loss by the weighted average number of common shares outstanding for the period. Diluted earnings per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. For purposes of determining earnings per common share, the potentially dilutive securities the Company has outstanding are stock options, SARs, restricted stock units and performance shares. For the quarter ended December 31, 2017, 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 157,603 securities and 317,686 securities excluded as being antidilutive for the quarters ended December 31, 2017 and December 31, 2016, respectively.

Stock-Based Compensation. The Company granted 208,588 performance shares during the quarter ended December 31, 2017. The weighted average fair value of such performance shares was $50.95 per share for the quarter ended December 31, 2017. 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, 2017 must meet a performance goal related to relative return on capital over the performance cycle of October 1, 2017 to September 30, 2020. 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, 2017 must meet a performance goal related to relative total shareholder return over the performance cycle of October 1, 2017 to September 30, 2020. 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 89,672 non-performance based restricted stock units during the quarter ended December 31, 2017. The weighted average fair value of such non-performance based restricted stock units was $51.23 per share for the quarter ended December 31, 2017. 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.

New Authoritative Accounting and Financial Reporting Guidance. In May 2014, the FASB issued authoritative guidance regarding revenue recognition. The authoritative guidance provides a single, comprehensive revenue

recognition model for all contracts with customers to improve comparability. The revenue standard contains principles that an entity will apply to determine the measurement of revenue and timing of when it is recognized. The original effective date of this authoritative guidance was as of the Company's first quarter of fiscal 2018. However, the FASB has delayed the effective date of the new revenue standard by one year, and the guidance will now be effective as of the Company's first quarter of fiscal 2019. Working towards this implementation date, the Company is currently evaluating the guidance and the various issues identified by industry based revenue recognition task forces. The Company does not believe that its revenue recognition policies will change materially, although the Company is still assessing the impact. The Company will need to enhance its financial statement disclosures to comply with the new authoritative guidance.
In February 2016, the FASB issued authoritative guidance requiring organizations that lease assets to recognize on the balance sheet the assets and liabilities for the rights and obligations created by all leases, regardless of whether they are considered to be capital leases or operating leases. The FASB’s previous authoritative guidance required organizations that lease assets to recognize on the balance sheet the assets and liabilities for the rights and obligations created by capital leases while excluding operating leases from balance sheet recognition. The new authoritative guidance will be effective as of the Company’s first quarter of fiscal 2020, with early adoption permitted. The Company does not anticipate early adoption and is currently evaluating the provisions of the revised guidance.

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In March 2016, the FASB issued authoritative guidance simplifying several aspects of the accounting for stock-based compensation. The Company adopted this guidance effective as of October 1, 2016, recognizing a cumulative effect adjustment that increased retained earnings by $31.9 million. The cumulative effect represents the tax benefit of previously unrecognized tax deductions in excess of stock compensation recorded for financial reporting purposes. On a prospective basis, the tax effect of all future differences between stock compensation recorded for financial reporting purposes and actual tax deductions for stock compensation will be recognized upon vesting or settlement as income tax expense or benefit in the income statement. From a statement of cash flows perspective, the tax benefits relating to differences between stock compensation recorded for financial reporting purposes and actual tax deductions for stock compensation are now included in cash provided by operating activities instead of cash provided by financing activities. The changes to the statement of cash flows were applied prospectively at the time of adoption.

In March 2017, the FASB issued authoritative guidance related to the presentation of net periodic pension cost and net periodic postretirement benefit cost. The new guidance requires segregation of the service cost component from the other components of net periodic pension cost and net periodic postretirement benefit cost for financial reporting purposes. The service cost component is to be presented on the income statement in the same line items as other compensation costs included within Operating Expenses and the other components of net periodic pension cost and net periodic postretirement benefit cost are to be presented on the income statement below the subtotal labeled Operating Income (Loss). Under this guidance, the service cost component shall be the only component eligible to be capitalized as part of the cost of inventory or property, plant and equipment. The new guidance will be effective as of the Company’s first quarter of fiscal 2019, with early adoption permitted. The Company does not anticipate early adoption and is currently evaluating the interaction of this authoritative guidance with the various regulatory provisions concerning pension and postretirement benefit costs in the Company’s Utility and Pipeline and Storage segments.

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.

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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, 2017 and September 30, 2017. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The fair value presentation for over the counter swaps combines gas and oil swaps because a significant number of the counterparties enter into both gas and oil swap agreements with the Company.

Recurring Fair Value Measures	At fair value as of December 31, 2017				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
Assets:					
Cash Equivalents – Money Market Mutual Funds	$132,231	$—	$ —	$ —	$132,231
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	1,374	—	—	(1,374)	—
Over the Counter Swaps – Gas and Oil	—	30,853	—	(10,312)	20,541
Foreign Currency Contracts	—	1,232	—	(666)	566
Other Investments:					
Balanced Equity Mutual Fund	36,979	—	—	—	36,979
Fixed Income Mutual Fund	44,232	—	—	—	44,232
Common Stock – Financial Services Industry	3,239	—	—	—	3,239
Hedging Collateral Deposits	4,465	—	—	—	4,465
Total	$222,520	$32,085	$ —	$ (12,352)	$242,253
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	$2,190	$—	$ —	$ (1,374)	$816
Over the Counter Swaps – Gas and Oil	—	16,312	—	(10,312)	6,000
Foreign Currency Contracts	—	429	—	(666)	(237)
Total	$2,190	$16,741	$ —	$ (12,352)	$6,579
Total Net Assets/(Liabilities)	$220,330	$15,344	$ —	$ —	$235,674

Recurring Fair Value Measures	At fair value as of September 30, 2017				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
Assets:					
Cash Equivalents – Money Market Mutual Funds	$527,978	$—	$ —	$ —	$527,978
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	1,483	—	—	(963)	520
Over the Counter Swaps – Gas and Oil	—	38,977	—	(4,206)	34,771
Foreign Currency Contracts	—	1,227	—	(407)	820
Other Investments:					
Balanced Equity Mutual Fund	37,033	—	—	—	37,033
Fixed Income Mutual Fund	45,727	—	—	—	45,727
Common Stock – Financial Services Industry	3,150	—	—	—	3,150
Hedging Collateral Deposits	1,741	—	—	—	1,741
Total	$617,112	$40,204	$ —	$ (5,576)	$651,740
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts – Gas	$963	$—	$ —	$ (963)	$—

Over the Counter Swaps – Gas and Oil	—	5,309	—	(4,206)	1,103
Foreign Currency Contracts	—	407	—	(407)	—
Total	$963	$5,716	$ —	$ (5,576)	$1,103
Total Net Assets/(Liabilities)	$616,149	$34,488	$ —	$ —	$650,637

(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.

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Derivative Financial Instruments

At December 31, 2017 and September 30, 2017, 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 were $4.5 million at December 31, 2017 and $1.7 million at September 30, 2017, which were associated with these futures contracts and have been reported in Level 1 as well. The derivative financial instruments reported in Level 2 at December 31, 2017 and September 30, 2017 consist of natural gas price swap agreements used in the Company’s Exploration and Production and Energy Marketing segments, crude oil price swap agreements used in the Company’s Exploration and Production segment and foreign currency contracts used in the Company's Exploration and Production segment. The derivative financial instruments reported in Level 2 at December 31, 2017 also include basis hedge swap agreements used in the Company's Energy Marketing segment. The fair value of the Level 2 price swap agreements is based on an internal, discounted cash flow model that uses observable inputs (i.e. LIBOR based discount rates and basis differential information, if applicable, at active natural gas and crude oil trading markets). The fair value of the Level 2 foreign currency contracts is determined using the market approach based on observable market transactions of forward Canadian currency rates.

The 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, 2017, the Company determined that nonperformance risk would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty's (assuming the derivative is in a gain position) or the Company’s (assuming the derivative is in a loss position) credit default swaps rates.

For the quarters ended December 31, 2017 and December 31, 2016, there were no assets or liabilities measured at fair value and classified as Level 3. For the quarters ended December 31, 2017 and December 31, 2016, no transfers in or out of Level 1 or Level 2 occurred.

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, 2017		September 30, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt	$2,084,465	$2,214,839	$2,383,681	$2,523,639

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

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

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

Other investments include cash surrender values of insurance contracts (net present value in the case of split-dollar collateral assignment arrangements) and marketable equity and fixed income securities. The values of the insurance contracts amounted to $38.9 million at December 31, 2017 and $39.4 million at September 30, 2017. The fair value of the equity mutual fund was $37.0 million at both December 31, 2017 and September 30, 2017. The gross unrealized gain on this equity mutual fund was $9.5 million at December 31, 2017 and $9.9 million at September 30, 2017. A sale of shares in the equity mutual fund during

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the quarter ended December 31, 2017 resulted in $1.5 million of cash proceeds and a realized gain of $0.4 million. The fair value of the fixed income mutual fund was $44.2 million at December 31, 2017 and $45.7 million at September 30, 2017. The gross unrealized loss on this fixed income mutual fund was $0.2 million at December 31, 2017 and was less than $0.1 million at September 30, 2017. A sale of shares in the fixed income mutual fund during the quarter ended December 31, 2017 resulted in $1.5 million of cash proceeds and a realized loss of less than $0.1 million. The fair value of the stock of an insurance company was $3.2 million at both December 31, 2017 and September 30, 2017. The gross unrealized gain on this stock was $2.3 million at December 31, 2017 and $2.2 million at September 30, 2017. The insurance contracts and marketable equity and fixed income securities are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees.

Derivative Financial Instruments. The Company uses derivative financial instruments to manage commodity price risk in the Exploration and Production segment as well as the Energy Marketing segment. The Company enters into futures contracts and over-the-counter swap agreements for natural gas and crude oil to manage the price risk associated with forecasted sales of gas and oil. In addition, the Company also enters into foreign exchange forward contracts to manage the risk of currency fluctuations associated with transportation costs denominated in Canadian currency in the Exploration and Production segment. These instruments are accounted for as cash flow hedges. The Company also enters into futures contracts and swaps, which are accounted for as cash flow hedges, to manage the price risk associated with forecasted gas purchases. The Company enters into futures contracts and swaps to mitigate risk associated with fixed price sales commitments, fixed price purchase commitments, and the decline in value of natural gas held in storage. These instruments are accounted for as fair value hedges. The duration of the Company’s combined cash flow and fair value commodity hedges does not typically exceed 5 years while the foreign currency forward contracts do not exceed 8 years. The Exploration and Production segment holds the majority of the Company’s derivative financial instruments.

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, 2017 and September 30, 2017. Substantially all of the derivative financial instruments reported on those line items relate to commodity contracts and a small portion relates to foreign currency forward contracts.

Cash Flow Hedges

For derivative instruments that are designated and qualify as a cash flow hedge, the effective portion of the gain or loss on the derivative is reported as a component of other comprehensive income (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, 2017, the Company had the following commodity derivative contracts (swaps and futures contracts) outstanding:

Commodity	Units	
Natural Gas	99.1	Bcf (short positions)
Natural Gas	1.6	Bcf (long positions)
Crude Oil	3,645,000	Bbls (short positions)

As of December 31, 2017, the Company was hedging a total of $94.7 million of forecasted transportation costs denominated in Canadian dollars with foreign currency forward contracts (long positions).
As of December 31, 2017, the Company had $17.5 million ($10.3 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that $5.0 million ($3.0 million after tax) of

such unrealized gains will be reclassified into the Consolidated Statement of Income within the next 12 months as the underlying hedged transaction are recorded in earnings.

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The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Three Months Ended December 31, 2017 and 2016 (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,	
	2017	2016		2017	2016		2017	2016
Commodity Contracts	$(5,948)	$(50,444)	Operating Revenue	$12,842	$31,320	Operating Revenue	$(433)	$(100)
Commodity Contracts	956	(1,536)	Purchased Gas	196	(460)	Not Applicable	—	—
Foreign Currency Contracts	(507)	(521)	Operation and Maintenance Expense	(490)	(143)	Not Applicable	—	—
Total	$(5,499)	$(52,501)		$12,548	$30,717		$(433)	$(100)

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 net realizable value writedown of the value of natural gas in storage that is recorded in the Company's financial statements. As of December 31, 2017, the Company's Energy Marketing segment had fair value hedges covering approximately 21.2 Bcf (20.6 Bcf of fixed price sales commitments and 0.6 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	Amount of Gain or (Loss) on the

		Derivative Recognized in the Consolidated Statement of Income for the Three Months Ended December 31, 2017 (In Thousands)	Hedged Item Recognized in the Consolidated Statement of Income for the Three Months Ended December 31, 2017 (In Thousands)
Commodity Contracts	Operating Revenues	$ (1,753)	$ 1,753
Commodity Contracts	Purchased Gas	$ 137	$ (137)
		$ (1,616)	$ 1,616

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

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basis monitors counterparty credit exposure. The majority of the Company’s counterparties are financial institutions and energy traders. The Company has over-the-counter swap positions and applicable foreign currency forward contracts with sixteen counterparties of which ten are in a net gain position. On average, the Company had $2.1 million of credit exposure per counterparty in a gain position at December 31, 2017. The maximum credit exposure per counterparty in a gain position at December 31, 2017 was $8.1 million. As of December 31, 2017, 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, 2017, thirteen of the sixteen counterparties to the Company’s outstanding derivative instrument contracts (specifically the over-the-counter swaps and applicable foreign currency forward contracts) had a common credit-risk related contingency feature. In the event the Company’s credit rating increases or falls below a certain threshold (applicable debt ratings), the available credit extended to the Company would either increase or decrease. A decline in the Company’s credit rating, in and of itself, would not cause the Company to be required to increase the level of its hedging collateral deposits (in the form of cash deposits, letters of credit or treasury debt instruments). If the Company’s outstanding derivative instrument contracts were in a liability position (or if the liability were larger) and/or the Company’s credit rating declined, then additional hedging collateral deposits may be required. At December 31, 2017, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $19.2 million according to the Company’s internal model (discussed in Note 2 — Fair Value Measurements). At December 31, 2017, the fair market value of the derivative financial instrument liabilities with a credit-risk related contingency feature was $4.2 million according to the Company's internal model (discussed in Note 2 - Fair Value Measurements). For its over-the-counter swap agreements and foreign currency forward contracts, no hedging collateral deposits were required to be posted by the Company at December 31, 2017.

For its exchange traded futures contracts, the Company was required to post $4.5 million in hedging collateral deposits as of December 31, 2017. As these are exchange traded futures contracts, there are no specific credit-risk related contingency features. The Company posts or receives hedging collateral based on open positions and margin requirements it has with its counterparties.

The Company’s requirement to post hedging collateral deposits and the Company's right to receive hedging collateral deposits is based on the fair value determined by the Company’s counterparties, which may differ from the Company’s assessment of fair value. Hedging collateral deposits may also include closed derivative positions in which the broker has not cleared the cash from the account to offset the derivative liability. The Company records liabilities related to closed derivative positions in Other Accruals and Current Liabilities on the Consolidated Balance Sheet. These liabilities are relieved when the broker clears the cash from the hedging collateral deposit account. This is discussed in Note 1 under Hedging Collateral Deposits.

Note 4 - Income Taxes

The effective tax rate for the quarters ended December 31, 2017 and December 31, 2016 was negative 69.2% and 38.8%, respectively. The difference is a result of the impact of the one-time remeasurement of the deferred income tax liability and a lower statutory rate of 24.5% as a result of the 2017 Tax Reform Act (as discussed below).
On December 22, 2017, the tax legislation referred to as the “Tax Cuts and Jobs Act” (the 2017 Tax Reform Act) was enacted. The 2017 Tax Reform Act significantly changes the taxation of business entities and includes specific provisions related to rate regulated companies. The more significant changes that impact the Company are the reduction in the corporate federal income tax rate from 35% to a blended 24.5% for fiscal 2018 and 21% for fiscal 2019 and beyond. As a fiscal year taxpayer, the Company is required to use a blended tax rate for fiscal 2018. In

addition, beginning in fiscal 2019, the corporate alternative minimum tax will be eliminated and there will be enhanced limitations on the deductibility of certain executive compensation. For the rate regulated subsidiaries, the 2017 Tax Reform Act also allows for the continued deductibility of interest expense, the elimination of full expensing for tax purposes of certain property acquired after September 27, 2017 and the continuation of certain rate normalization requirements for accelerated depreciation benefits. The non-rate regulated subsidiaries are allowed full expensing of certain property acquired after September 27, 2017 and have potential limitations on the deductibility of interest expense beginning in fiscal 2019.

The above changes had a material impact on the financial statements in the quarter ended December 31, 2017. Under GAAP, the tax effects of a change in tax law must be recognized in the period in which the law is enacted, or the quarter ending December 31, 2017 for the 2017 Tax Reform Act. GAAP also requires deferred income tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences are to be realized or settled. The Company’s deferred income taxes were remeasured based upon the new tax rates. For the non-rate regulated activities, the change in deferred income taxes was $111.0 million and was recorded as a reduction to income tax expense. For the rate regulated activities, the reduction in

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deferred income taxes of $336.7 million was recorded as a decrease to Recoverable Future Taxes of $65.7 million and an increase to Taxes Refundable to Customers of $271.0 million. The 2017 Tax Reform Act includes provisions that stipulate how these excess deferred taxes are to be passed back to customers for certain accelerated tax depreciation benefits. Potential refunds of other deferred income taxes will be determined by the federal and state regulatory agencies. The Company is awaiting regulatory guidance in the jurisdictions in which it operates.

The 2017 Tax Reform Act also repealed the corporate alternative minimum tax (AMT) and provides that the Company's existing AMT credit carryovers are refundable beginning in fiscal 2019. As of December 31, 2017, the Company had $92.0 million of AMT credit carryovers that are expected to be utilized or refunded between fiscal 2019 and fiscal 2022.

The SEC issued guidance in Staff Accounting Bulletin 118 (SAB 118) which provides for up to a one year period (the measurement period) in which to complete the required analysis and income tax accounting for the 2017 Tax Reform Act. SAB 118 describes three scenarios associated with a company's status of accounting for income tax reform: (1) a company is complete with its accounting for certain effects of tax reform, (2) a company is able to determine a reasonable estimate for certain effects of tax reform and records that estimate as a provisional amount, or (3) a company is not able to determine a reasonable estimate and therefore continues to apply the provisions of the tax laws that were in effect immediately prior to the 2017 Tax Reform Act being enacted.

The Company has determined a reasonable estimate for the measurement of the changes in deferred income taxes (noted above), which have been reflected as provisional amounts in the December 31, 2017 financial statements. The final determination of the impact of the income tax effects of these items will require additional analysis and further interpretation of the 2017 Tax Reform Act from yet to be issued U.S. Treasury regulations, state income tax guidance, federal and state regulatory guidance and technical corrections.

Note 5 - Capitalization

Common Stock. During the three months ended December 31, 2017, the Company issued 63,082 original issue shares of common stock as a result of SARs exercises, 68,534 original issue shares of common stock for restricted stock units that vested and 79,079 original issue shares of common stock for performance shares that vested. In addition, the Company issued 25,453 original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan and 25,879 original issue shares of common stock for the Company's 401(k) plans. The Company also issued 6,912 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, 2017. 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, 2017, 51,218 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, 2017 will mature within the following twelve-month period. Current Portion of Long-Term Debt at September 30, 2017 consisted of $300.0 million of 6.50% notes scheduled to mature in April 2018. The Company redeemed these notes on October 18, 2017 for $307.0 million, plus accrued interest. The call premium was recorded to Unamortized Debt Expense on the Consolidated Balance Sheet in October 2017.

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, 2017, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites will be approximately $3.0 million. This estimated liability has been recorded in Other Deferred Credits on the Consolidated Balance Sheet at December 31, 2017. The Company expects to recover its environmental clean-up costs through rate recovery over a period of approximately 4 years. The Company is currently not aware of any material additional exposure to environmental liabilities. However, changes in environmental laws and regulations, new information or other factors could have an adverse financial impact on the Company.

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Northern Access 2016 Project. On February 3, 2017, Supply Corporation and Empire received FERC approval of the Northern Access 2016 project described herein. On April 7, 2017, the NYDEC issued a Notice of Denial of the federal Clean Water Act Section 401 Water Quality Certification and other state stream and wetland permits for the New York portion of the project (the Water Quality Certification for the Pennsylvania portion of the project was received on January 27, 2017). On April 21, 2017, Supply Corporation and Empire filed a Petition for Review in the United States Court of Appeals for the Second Circuit of the NYDEC's Notice of Denial with respect to National Fuel's application for the Water Quality Certification, and on May 11, 2017, the Company commenced legal action in New York State Supreme Court challenging the NYDEC's actions with regard to various state permits. The Company also has pending with FERC a proceeding asserting, among other things, that the NYDEC exceeded the reasonable and statutory time frames to take action under the Clean Water Act and, therefore, waived its opportunity to approve or deny the Water Quality Certification. In light of these pending legal actions, the Company has not yet determined a target in-service date. As a result of the decision of the NYDEC, Supply Corporation and Empire evaluated the capitalized project costs for impairment as of December 31, 2017 and determined that an impairment charge was not required. The evaluation considered probability weighted scenarios of undiscounted future net cash flows, including a scenario assuming successful resolution with the NYDEC and construction of the pipeline, as well as a scenario where the project does not proceed. Further developments or indicators of an unfavorable resolution could result in the impairment of a significant portion of the project costs, which totaled $75.5 million at December 31, 2017. The project costs are included within Property, Plant and Equipment and Deferred Charges on the Consolidated Balance Sheet.

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 2017 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 2017 Form 10-K. A listing of segment assets at December 31, 2017 and September 30, 2017 is shown in the tables below.

Quarter Ended December 31, 2017
(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	$139,141	$53,310	$170	$187,089	$38,636	$418,346	$1,096	$213	$419,655

Customers									
Intersegment Revenues	$—	$21,985	$23,665	$2,182	$126	$47,958	$—	$(47,958)	$—
Segment Profit: Net Income (Loss)	$106,698	$38,462	$45,400	$20,993	$1,046	$212,599	$(719)	$(13,226)	$198,654

(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, 2017	$1,420,790	$1,793,848	$589,793	$1,988,758	$72,466	$5,865,655	$77,214	$(150,937)	$5,791,932
At September 30, 2017	$1,407,152	$1,929,788	$580,051	$2,013,123	$60,937	$5,991,051	$76,861	$35,408	$6,103,320

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Quarter Ended December 31, 2016
(Thousands)

	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$160,932	$53,000	$26	$170,971	$36,809	$421,738	$554	$208	$422,500
Intersegment Revenues	$—	$22,155	$27,840	$1,826	$19	$51,840	$—	$(51,840)	$—
Segment Profit: Net Income (Loss)	$35,080	$19,368	$10,981	$21,175	$1,782	$88,386	$(179)	$701	$88,908

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,	2017	2016	2017	2016
Service Cost	$2,480	$2,992	$458	$612
Interest Cost	8,252	9,596	3,700	4,752
Expected Return on Plan Assets	(15,429)	(14,929)	(7,871)	(7,865)
Amortization of Prior Service Cost (Credit)	235	264	(107)	(107)
Amortization of Losses	9,301	10,672	2,639	4,604
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) (1)	1,721	535	3,608	1,312
Net Periodic Benefit Cost	$6,560	$9,130	$2,427	$3,308

(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, 2017, the Company contributed $27.6 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $0.7 million to its VEBA trusts for its other post-retirement benefits. In the remainder of 2018, the Company may contribute up to $5.0 million to the Retirement Plan. In the remainder of 2018, the Company expects its contributions to the VEBA trusts to be in the range of $2.0 million to $3.0 million.

Note 9 – Regulatory Matters

On April 28, 2016, Distribution Corporation commenced a rate case by filing proposed tariff amendments and supporting testimony requesting approval to increase its annual revenues by approximately $41.7 million. Distribution Corporation explained in the filing that its request for rate relief was necessitated by a revenue requirement driven primarily by rate base growth, higher operating expense and higher depreciation expense, among other things. On January 23, 2017, the administrative law judge assigned to the proceeding issued a recommended decision (RD) in the case. The RD, as revised on January 26, 2017, recommended a rate increase designed to provide additional annual revenues of $8.5 million, an equity ratio, subject to update of 42.3% based on the Company's equity ratio, and a cost of equity, subject to update of 8.6%. On April 20, 2017, the NYPSC issued an Order adopting some provisions of the RD and modifying or rejecting others. The Order provides for an annual rate increase of $5.9 million. The rate increase became effective May 1, 2017. The Order further provides for a return on equity of 8.7%, and established an equity ratio of 42.9%. The Order also directs the implementation of an earnings sharing mechanism to be in place beginning on April 1, 2018.

On July 28, 2017, Distribution Corporation filed an appeal with New York State Supreme Court, Albany County, seeking review of the Order. The appeal contends that portions of the Order should be invalidated because they fail to meet the applicable legal standard for agency decisions. On December 11, 2017, the appeal was transferred to the Supreme Court, Appellate Division, Third Department. The Company cannot predict the outcome of the appeal at this time.

On December 22, 2017, the federal Tax Cuts and Jobs Act (the 2017 Tax Reform Act) was enacted into law. On December 29, 2017, the NYPSC issued an order instituting a proceeding to study the potential effects of the enactment of the 2017 Tax Reform Act on the tax expenses and liabilities of New York utilities, and the "regulatory treatment of any windfalls resulting from same in order to preserve the benefits for ratepayers." In its order, the NYPSC stated that the effect of the 2017 Tax Reform Act on utilities' taxation is likely to be material and complex and that the proceeding was needed to begin the process of addressing the impact on the State's utilities and ratepayers. The order establishes that the first steps in such process will be soliciting information from its regulated utilities to quantify the impact of the 2017 Tax Reform Act, scheduling a technical conference with the utilities, and the issuance of a NY Department of Public Service Staff (Staff) proposal for accounting and ratemaking treatment of the tax changes. The order further states that once Staff's proposal is issued, utilities and other interested parties will be invited to comment on Staff's recommendation. The order also declares that utilities are "put on notice that it is the [NYPSC]'s intent to ensure that net benefits accruing from the Tax Act are preserved for ratepayers, either through deferral accounting or another method, from the first day the Tax Act is put into effect. Utilities acting contrary to this intent do so at their own risk." The Company cannot predict the outcome of this proceeding at this time. Refer to Note 4 - Income Taxes for further discussion of the 2017 Tax Reform Act.

FERC Rate Proceedings

Supply Corporation currently has no active rate case on file. Supply Corporation's current rate settlement requires a rate case filing no later than December 31, 2019.

Empire currently has no active rate case on file. Empire's current rate settlement requires a rate case filing no later than July 1, 2021.

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

OVERVIEW

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

The Company is a diversified energy company engaged principally in the production, gathering, transportation, distribution and marketing of natural gas. The Company operates an integrated business, with assets centered in western New York and Pennsylvania, being utilized for, and benefiting from, the production and transportation of natural gas from the Appalachian basin. Current development activities are focused primarily in the Marcellus and Utica Shale. The common geographic footprint of the Company’s subsidiaries enables them to share management, labor, facilities and support services across various businesses and pursue coordinated projects designed to produce and transport natural gas from the Appalachian basin to markets in Canada and the eastern United States. The Company's efforts in this regard are not limited to affiliated projects. The Company has also been designing and building pipeline projects for the transportation of natural gas for non-affiliated natural gas producers in the Appalachian basin. 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, 2017 compared to the quarter ended December 31, 2016, the Company experienced an increase in earnings of $109.8 million. On December 22, 2017, the tax legislation referred to as the “Tax Cuts and Jobs Act” (the 2017 Tax Reform Act) was enacted. The 2017 Tax Reform Act significantly changes the taxation of business entities and includes specific provisions related to rate regulated companies. The more significant changes that impact the Company are the reduction in the corporate federal income tax rate from 35% to a blended 24.5% for fiscal 2018 and 21% for fiscal 2019 and beyond. As a fiscal year taxpayer, the Company is required to use a blended tax rate for fiscal 2018. As a result of the 2017 Tax Reform Act, the effective tax rate for the three months ended December 31, 2017 (negative 69.2%) reflects the impact of a one-time remeasurement of the Company's accumulated deferred income tax liability, a $111.0 million reduction to income tax expense. The effective tax rate also reflects a lower statutory rate of 24.5%. Without the one-time remeasurement of the Company's accumulated deferred income tax liability, the effective tax rate would have been 25.3%. For further discussion of the impact of the 2017 Tax Reform Act to the Company, refer to Item 1 at Note 4 — Income Taxes. For further discussion of the Company’s earnings, refer to the Results of Operations section below.

On February 3, 2017, the Company, in its Pipeline and Storage segment, received FERC approval of a project to move significant prospective Marcellus production from Seneca’s Western Development Area at Clermont to an Empire interconnection with TransCanada Pipeline at Chippawa and an interconnection with Tennessee Gas Pipeline’s 200 Line in East Aurora, New York (“Northern Access 2016”). On April 7, 2017, the NYDEC issued a Notice of Denial of the federal Clean Water Act Section 401 Water Quality Certification and other state stream and wetland permits for the New York portion of the project (the Water Quality Certification for the Pennsylvania portion of the project was received on January 27, 2017). On April 21, 2017, the Company appealed the NYDEC's decision with regard to the Water Quality Certification to the United States Court of Appeals for the Second Circuit, and on May 11, 2017, the Company commenced legal action in New York State Supreme Court challenging the NYDEC's actions with regard to various state permits. The Company also has pending with FERC a proceeding asserting, among other things, that the NYDEC exceeded the reasonable and statutory time frames to take action under the Clean Water Act and, therefore, waived its opportunity to approve or deny the Water Quality Certification. The Company remains committed to the project. Approximately $75.5 million in costs have been incurred on this project through December 31, 2017, with the costs residing either in Construction Work in Progress, a component of Property, Plant and Equipment on the

Consolidated Balance Sheet, or Deferred Charges.

Seneca has two downstream Canadian transportation contracts to move incremental volumes associated with the Northern Access 2016 project. One of the contracts has a term expiring on March 31, 2023 with a remaining commitment of approximately $27.1 million (using a 1.2545 Exchange Rate). The other transportation precedent agreement was suspended until the Northern Access 2016 project has received all its necessary permits. Seneca paid $2.4 million associated with this suspension during the quarter ended September 30, 2017 and will be reimbursed this amount if the project is reinstated. As noted above, the Company remains committed to the Northern Access 2016 project. Seneca has mitigated a portion of the current capacity costs through capacity release arrangements.

From a financing perspective, in September 2017, the Company issued $300.0 million of 3.95% notes due in September 2027. The proceeds of the debt issuance were used for the October 2017 redemption of $300.0 million of the Company's 6.50% notes that were scheduled to mature in April 2018. The Company expects to use cash on hand and cash from operations to meet

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its capital expenditure needs for the remainder of fiscal 2018 and may issue short-term and/or long-term debt during fiscal 2018 as needed.

CRITICAL ACCOUNTING ESTIMATES

For a complete discussion of critical accounting estimates, refer to "Critical Accounting Estimates" in Item 7 of the Company's 2017 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, 2017, the ceiling exceeded the book value of the oil and gas properties by approximately $334.6 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, 2017, based on posted Midway Sunset prices, was $48.41 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, 2017, based on the quoted Henry Hub spot price for natural gas, was $2.98 per MMBtu. (Note – because actual pricing of the Company’s various producing properties varies depending on their location and hedging, the prices used to calculate the ceiling may differ from the Midway Sunset and Henry Hub prices, which are only indicative of the 12-month average prices for the twelve months ended December 31, 2017. Pricing differences would include adjustments for regional market differentials, transportation fees and contractual arrangements.) The following table illustrates the sensitivity of the ceiling test calculation to commodity price changes, specifically showing the amounts the ceiling would have exceeded the book value of the Company's oil and gas properties at December 31, 2017 (which would not have resulted in an impairment charge) if natural gas prices were $0.25 per MMBtu lower than the average prices used at December 31, 2017, if crude oil prices were $5 per Bbl lower than the average prices used at December 31, 2017, and if both natural gas prices and crude oil prices were $0.25 per MMBtu and $5 per Bbl lower than the average prices used at December 31, 2017 (all amounts are presented after-tax). These calculated amounts are based solely on price changes and do not take into account any other changes to the ceiling test calculation, including, among others, changes in reserve quantities and future cost estimates.

Ceiling Testing Sensitivity to Commodity Price Changes

(Millions)	$0.25/MMBtu Decrease in Natural Gas Prices	$5.00/Bbl Decrease in Crude Oil Prices	$0.25/MMBtu Decrease in Natural Gas Prices and $5.00/Bbl Decrease in Crude Oil Prices
Excess of Ceiling over Book Value under Sensitivity Analysis	$ 188.4	$ 295.4	$ 149.2

It is difficult to predict what factors could lead to future impairments under the SEC's full cost ceiling test. Fluctuations in or subtractions from proved reserves, increases in development costs for undeveloped reserves and significant fluctuations in oil and gas prices have an impact on the amount of the ceiling at any point in time. 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 2017 Form 10-K.

2017 Tax Reform Act. On December 22, 2017, the tax legislation referred to as the "Tax Cuts and Jobs Act" (the 2017 Tax Reform Act) was enacted. The 2017 Tax Reform Act significantly changes the taxation of business entities and includes specific provisions related to rate regulated companies. The more significant changes that impact the Company are the reduction in the corporate federal income tax rate from 35% to a blended 24.5% for fiscal 2018 and 21% for fiscal 2019 and beyond. As a fiscal year taxpayer, the Company is required to use a blended tax rate for fiscal 2018. In addition, beginning in fiscal 2019, the corporate alternative minimum tax will be eliminated and there will be enhanced limitations on the deductibility of certain executive compensation. For the rate regulated subsidiaries, the 2017 Tax Reform Act also allows for the continued deductibility of interest expense, the elimination of full expensing for tax purposes of certain property acquired after September 27, 2017 and the continuation of certain rate normalization requirements for accelerated depreciation benefits. The Company's non-rate regulated subsidiaries are allowed

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full expensing of certain property acquired after September 27, 2017 and have potential limitations on the deductibility of interest expense beginning in fiscal 2019.

The Company has determined a reasonable estimate under SAB 118 for the measurement of the changes in deferred income taxes in the December 31, 2017 financial statements. The final determination of the impact of the income tax effects of these items will require additional analysis and further interpretation of the 2017 Tax Reform Act from yet to be issued U.S. Treasury regulations, state income tax guidance, federal and state regulatory guidance and technical corrections. For further discussion of the impact of the 2017 Tax Reform Act to the Company, refer to Item 1 at Note 4 — Income Taxes.

RESULTS OF OPERATIONS

Earnings

The Company's earnings were $198.7 million for the quarter ended December 31, 2017 compared to earnings of $88.9 million for the quarter ended December 31, 2016. The increase in earnings of $109.8 million is primarily a result of higher earnings in the Exploration and Production segment, Gathering segment and Pipeline and Storage segment. Lower earnings in the Energy Marketing segment and Utility segment, as well as losses in the Corporate and All Other categories partially offset these increases.

The Company's earnings for the quarter ended December 31, 2017 include a $111.0 million remeasurement of accumulated deferred income taxes recorded during the quarter ended December 31, 2017 and a lower statutory rate of 24.5% as a result of the 2017 Tax Reform Act, as discussed above. Additional discussion of earnings in each of the business segments can be found in the business segment information that follows. Note that all amounts used in the earnings discussions are after-tax amounts, unless otherwise noted.

Earnings (Loss) by Segment

	Three Months Ended December 31,		
(Thousands)	2017	2016	Increase (Decrease)
Exploration and Production	$106,698	$35,080	$71,618
Pipeline and Storage	38,462	19,368	19,094
Gathering	45,400	10,981	34,419
Utility	20,993	21,175	(182)
Energy Marketing	1,046	1,782	(736)
Total Reportable Segments	212,599	88,386	124,213
All Other	(719)	(179)	(540)
Corporate	(13,226)	701	(13,927)
Total Consolidated	$198,654	$88,908	$109,746

Exploration and Production

Exploration and Production Operating Revenues

	Three Months Ended December 31,	
(Thousands)	2017	2016

			Increase (Decrease)
Gas (after Hedging)	$98,115	$120,564	$(22,449)
Oil (after Hedging)	40,214	39,457	757
Gas Processing Plant	1,065	761	304
Other	(253)	150	(403)
	$139,141	$160,932	$(21,791)

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Production Volumes

	Three Months Ended December 31,		
	2017	2016	Increase (Decrease)
Gas Production (MMcf)			
Appalachia	35,414	39,807	(4,393)
West Coast	695	776	(81)
Total Production	36,109	40,583	(4,474)
Oil Production (Mbbl)			
Appalachia	1	—	1
West Coast	672	721	(49)
Total Production	673	721	(48)

Average Prices

	Three Months Ended December 31,		
	2017	2016	Increase (Decrease)
Average Gas Price/Mcf			
Appalachia	$2.35	$2.35	$ —
West Coast	$5.00	$4.24	$ 0.76
Weighted Average	$2.40	$2.39	$ 0.01
Weighted Average After Hedging	$2.72	$2.97	$ (0.25)
Average Oil Price/Bbl			
Appalachia	$43.85	N/M	N/M
West Coast	$57.88	$43.69	$ 14.19
Weighted Average	$57.86	$43.82	$ 14.04
Weighted Average After Hedging	$59.79	$54.71	$ 5.08

N/M - Not Meaningful

2017 Compared with 2016

Operating revenues for the Exploration and Production segment decreased $21.8 million for the quarter ended December 31, 2017 as compared with the quarter ended December 31, 2016. Gas production revenue after hedging decreased $22.4 million primarily due to a decrease in gas production coupled with a $0.25 per Mcf decrease in the weighted average price of gas after hedging. The decrease in production was primarily due to natural declines from Marcellus wells in the Eastern Development Area. This was partially offset by production increases in the Western Development Area from new Marcellus and Utica wells coupled with a decrease in price-related curtailments during the quarter ended December 31, 2017 compared to the quarter ended December 31, 2016. This decrease to operating revenues was partially offset by an increase in oil production revenue after hedging of $0.8 million. The increase in oil production revenue was due to a $5.08 per Bbl increase in the weighted average price of oil after hedging, which was largely offset by a decrease in crude oil production. The decrease in crude oil production in the West Coast region was largely due to the lagging current year impact of decreased steam operations and well workover activity at its North Midway Sunset field in prior years (due to lower crude oil prices) coupled with oil production losses due to temporary shut-in production in Ventura County, California in response to the wildfires occurring in fiscal 2018. During the quarter ended December 31, 2017, there was an increase in steam operations and well workover activity versus the quarter ended December 31, 2016, which will stimulate future crude oil production.

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The Exploration and Production segment's earnings for the quarter ended December 31, 2017 were $106.7 million, an increase of $71.6 million when compared with earnings of $35.1 million for the quarter ended December 31, 2016. The increase in earnings primarily reflects the remeasurement of accumulated deferred income taxes ($77.3 million) combined with the current period earnings impact of the change in federal tax rate from 35% to a blended rate of 24.5% for fiscal 2018 on current income taxes ($4.1 million), both of which were the result of the 2017 Tax Reform Act. It also reflects higher crude oil prices after hedging ($2.2 million), lower depletion expense ($1.1 million) and lower income tax expense, excluding the impact of the 2017 Tax Reform Act ($3.9 million). The decrease in depletion expense was due to a decrease in production coupled with an increase in reserves (an increase in reserves lowers the per mcf/barrel depletion rate) partially offset by an increase in capitalized costs. The decrease in income tax expense, excluding the impact of the 2017 Tax Reform Act, was largely due to an increase in the enhanced oil recovery tax credit related to Seneca's California properties coupled with a decrease in state income taxes as a result of lower pre-tax net income for the Exploration and Production segment. These factors, which contributed to increased earnings during the quarter ended December 31, 2017 compared to the quarter ended December 31, 2016, were partially offset by lower natural gas prices after hedging ($6.0 million), lower natural gas production ($8.6 million), lower crude oil production ($1.7 million) and higher other operating expenses ($0.6 million). The increase in other operating expenses was primarily due to an increase in personnel costs.

Pipeline and Storage

Pipeline and Storage Operating Revenues

	Three Months Ended December 31,		
(Thousands)	2017	2016	Increase (Decrease)
Firm Transportation	$56,756	$56,749	$ 7
Interruptible Transportation	340	646	(306)
	57,096	57,395	(299)
Firm Storage Service	17,839	17,273	566
Interruptible Storage Service	19	12	7
Other	341	475	(134)
	$75,295	$75,155	$ 140

Pipeline and Storage Throughput

	Three Months Ended December 31,		
(MMcf)	2017	2016	Increase (Decrease)
Firm Transportation	206,701	190,781	15,920
Interruptible Transportation	882	3,046	(2,164)
	207,583	193,827	13,756

2017 Compared with 2016

Operating revenues for the Pipeline and Storage segment remained relatively flat for the quarter ended December 31, 2017 as compared with the quarter ended December 31, 2016. An increase in operating revenues due to demand charges for transportation service from Supply Corporation's Line D Expansion, which was placed in service on November 1, 2017, and an increase in both transportation and storage revenues due to Supply Corporation's greenhouse gas and pipeline safety surcharge effective November 1, 2017, were largely offset by a decline in transportation revenues due partially to an additional 2% reduction in Supply Corporation's rates effective November 1, 2016, which was required by the rate case settlement approved by FERC on November 13, 2015, and a decline in demand charges for transportation services as a result of contract terminations.

Transportation volume for the quarter ended December 31, 2017 increased by 13.8 Bcf from the prior year’s quarter. The increase in transportation volume for the quarter primarily reflects the impact of the Line D Expansion project being placed in service combined with colder weather quarter over quarter. Volume fluctuations, other than those caused by the addition or termination of contracts, generally do not have a significant impact on revenues as a result of the straight fixed-variable rate design utilized by Supply Corporation and Empire.

The Pipeline and Storage segment's earnings for the quarter ended December 31, 2017 were $38.5 million, an increase of $19.1 million when compared with earnings of $19.4 million for the quarter ended December 31, 2016. The increase in earnings was primarily due to lower income tax expense ($17.6 million) combined with lower operating expenses ($1.9 million) and a decrease in interest expense ($0.3 million). Income tax expense was lower due to the remeasurement of accumulated deferred income taxes ($14.1 million) combined with the current period earnings impact of the change in federal tax rate from 35% to a blended rate of 24.5% for fiscal 2018 ($3.5 million), both a result of the 2017 Tax Reform Act. The decrease in operating expenses primarily reflects lower pension and other post-retirement benefit costs combined with a decrease in the reserve for preliminary project costs. The decrease in interest expense was largely due to lower intercompany long-term borrowing interest rates for the Pipeline and Storage segment. These earnings increases were slightly offset by an increase in depreciation expense ($0.6 million) due to incremental depreciation expense related to expansion projects that were placed in service within the last year combined with the non-recurrence of a reduction to depreciation expense recorded in the quarter ended December 31, 2016 to reflect a reduction in depreciation rates retroactive to July 1, 2016 in accordance with Empire's rate case settlement. The FERC issued an order approving the settlement on December 13, 2016.

Looking ahead, the Pipeline and Storage segment expects transportation revenues to be negatively impacted in fiscal 2019 in an amount up to approximately $14 million as a result of an Empire system transportation contract reaching its termination date in December 2018. Management does not expect to renew the contract at existing rates given a change in market dynamics.

Gathering

Gathering Operating Revenues

(Thousands)	Three Months Ended December 31, 2017	2016	Increase (Decrease)
Gathering	$23,802	$27,840	$ (4,038)
Processing and Other Revenues	33	26	7
	$23,835	$27,866	$ (4,031)

Gathering Volume

	Three Months Ended December 31, 2017	2016	Increase (Decrease)
Gathered Volume - (MMcf)	43,162	50,569	(7,407)

2017 Compared with 2016

Operating revenues for the Gathering segment decreased $4.0 million for the quarter ended December 31, 2017 as compared with the quarter ended December 31, 2016, which was driven by a 7.4 Bcf decrease in gathered volume. The overall decrease in gathered volume was due to a 5.2 Bcf decrease in gathered volume on Midstream Corporation's Trout Run Gathering System (Trout Run), a 2.0 Bcf decrease in gathered volume on Midstream Corporation's Covington Gathering System (Covington), a 0.6 Bcf decrease in gathered volume on Midstream Corporation's Wellsboro Gathering System (Wellsboro), and a 0.1 Bcf decrease in gathered volumes spread across numerous Midstream systems. These decreases were partially offset by a 0.5 Bcf increase in gathered volume on

Midstream Corporation's Clermont Gathering System (Clermont). The decreases in the aforementioned volumes were largely due to a decrease in Seneca's production.

The Gathering segment’s earnings for the quarter ended December 31, 2017 were $45.4 million, an increase of $34.4 million when compared with earnings of $11.0 million for the quarter ended December 31, 2016. The increase in earnings was mainly due to the impact of the 2017 Tax Reform Act, which led to the remeasurement of accumulated deferred taxes ($34.9 million) and the impact of the tax rate change on current income tax ($1.5 million). These earnings increases were partially offset by lower gathering revenue ($2.6 million), as discussed above.

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Utility

Utility Operating Revenues

(Thousands)	Three Months Ended December 31, 2017	2016	Increase (Decrease)
Retail Sales Revenues:			
Residential	$134,739	$116,387	$18,352
Commercial	19,633	15,979	3,654
Industrial	872	517	355
	155,244	132,883	22,361
Transportation	36,309	36,661	(352)
Off-System Sales	41	627	(586)
Other	(2,323)	2,626	(4,949)
	$189,271	$172,797	$16,474

Utility Throughput

(MMcf)	Three Months Ended December 31, 2017	2016	Increase (Decrease)
Retail Sales:			
Residential	17,847	15,764	2,083
Commercial	2,596	2,299	297
Industrial	144	77	67
	20,587	18,140	2,447
Transportation	21,427	19,565	1,862
Off-System Sales	22	173	(151)
	42,036	37,878	4,158

Degree Days

Three Months Ended December 31,	Normal	2017	2016	Percent Colder (Warmer) Than Normal[1]	Prior Year[1]
Buffalo	2,253	2,227	1,966	(1.2)%	13.3%
Erie	2,044	2,029	1,750	(0.7)%	15.9%

(1) Percents compare actual 2017 degree days to normal degree days and actual 2017 degree days to actual 2016 degree days.

2017 Compared with 2016

Operating revenues for the Utility segment increased $16.5 million for the quarter ended December 31, 2017 as compared with the quarter ended December 31, 2016. The increase largely resulted from a $22.4 million increase in retail gas sales revenues. The increase in retail gas sales revenue was largely a result of higher volumes (due to colder weather) and an increase in the cost of gas sold (per Mcf). The increase in operating revenues was partially offset by a $0.4 million decrease in transportation revenues, a $4.9 million decrease in other revenues and a $0.6 million decrease in off-system sales (due to lower volumes). The $0.4 million decrease in transportation revenues was primarily due to the impact of regulatory adjustments, which more than offset the impact of larger volumes and colder weather. The $4.9 million decrease in other revenues was largely due to an estimated refund provision for the current income tax benefits resulting from the 2017 Tax Reform Act. Due to profit sharing with retail customers, the margins related to off-system sales are minimal.

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The Utility segment's earnings for the quarter ended December 31, 2017 were $21.0 million, a decrease of $0.2 million when compared with earnings of $21.2 million for the quarter ended December 31, 2016. Higher earnings associated with the new rate order issued by the NYPSC effective April 1, 2017 ($1.0 million) combined with the impact of colder weather in fiscal 2018 compared to fiscal 2017 ($1.2 million) were partially offset by an increase in operating expense ($0.7 million) and the impact of regulatory adjustments ($1.2 million). The increase in operating expense is primarily due to higher amortization of environmental remediation costs that resulted from the new rate order. The current tax benefit associated with the 2017 Tax Reform Act was completely offset by the aforementioned refund provision.

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, 2017, the WNC increased earnings by approximately $0.9 million as the weather was warmer than normal. For the quarter ended December 31, 2016, the WNC preserved earnings of $1.3 million as the weather was warmer than normal.

Energy Marketing

Energy Marketing Operating Revenues

(Thousands)	Three Months Ended December 31, 2017	2016	Increase (Decrease)
Natural Gas (after Hedging)	$38,730	$36,790	$ 1,940
Other	32	38	(6)
	$38,762	$36,828	$ 1,934

Energy Marketing Volume

	Three Months Ended December 31, 2017	2016	Increase (Decrease)
Natural Gas – (MMcf)	11,979	11,127	852

2017 Compared with 2016

Operating revenues for the Energy Marketing segment increased $1.9 million for the quarter ended December 31, 2017 as compared with the quarter ended December 31, 2016. The increase was primarily due to an increase in gas sales revenue due to an increase in volume sold to retail customers as a result of colder weather, offset slightly by a lower average price of natural gas period over period.

The Energy Marketing segment earnings for the quarter ended December 31, 2017 were $1.0 million, a decrease of $0.8 million when compared with earnings of $1.8 million for the quarter ended December 31, 2016. This decrease in earnings was primarily attributable to lower margin of $0.8 million. The decrease in margin largely reflects a decline in average margin per Mcf primarily due to stronger natural gas prices at local purchase points relative to NYMEX-based sales contracts. The 2017 Tax Reform Act did not have a significant impact on Energy Marketing segment earnings for the quarter ended December 31, 2017.

Corporate and All Other

2017 Compared with 2016

Corporate and All Other operations had a loss of $13.9 million for the quarter ended December 31, 2017, a decrease of $14.4 million when compared with earnings of $0.5 million for the quarter ended December 31, 2016. The earnings decrease for the quarter is primarily attributed to a remeasurement of accumulated deferred taxes under the 2017 Tax Reform Act ($15.1 million). This decrease in earnings was partially offset by higher margins ($0.4 million) from the sale of standing timber by Seneca's land and timber division and the current tax benefit of tax rate changes associated with the 2017 Tax Reform Act ($0.1 million).

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

Interest on long-term debt decreased $1.0 million for the quarter ended December 31, 2017 as compared with the quarter ended December 31, 2016. This decrease is due to a decrease in the weighted average interest rate on long-term debt outstanding. The Company issued $300 million of 3.95% notes in September 2017 and repaid $300 million of 6.5% notes in October 2017.

CAPITAL RESOURCES AND LIQUIDITY

The Company's primary source of cash during the three-month period ended December 31, 2017 consisted of cash provided by operating activities. The Company's primary sources of cash during the three-month period ended December 31, 2016 consisted of cash provided by operating activities and net proceeds from sale of oil and gas producing properties.

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 $94.8 million for the three months ended December 31, 2017, a decrease of $49.8 million compared with $144.6 million provided by operating activities for the three months ended December 31, 2016. The decrease in cash provided by operating activities reflects lower cash provided by operating activities in the Exploration and Production and Energy Marketing segments. The decrease in the Exploration and Production segment was primarily due to lower cash receipts from crude oil and natural gas production, primarily a result of lower natural gas prices and lower production. The decrease in the Energy Marketing segment was primarily a result of higher purchased gas costs and an increase in hedging collateral deposits. Hedging collateral deposits serve as collateral for open positions on exchange-trade futures contracts and over-the-counter swaps.

Investing Cash Flow

Expenditures for Long-Lived Assets

The Company’s expenditures for long-lived assets totaled $126.5 million during the three months ended December 31, 2017 and $94.6 million during the three months ended December 31, 2016. The table below presents these expenditures:

Total Expenditures for Long-Lived Assets

Three Months Ended December 31, (Millions)	2017		2016		Increase (Decrease)
Exploration and Production:					
Capital Expenditures	$74.7	(1)	$40.7	(2)	$ 34.0
Pipeline and Storage:					
Capital Expenditures	22.3	(1)	25.4	(2)	(3.1)
Gathering:					
Capital Expenditures	12.9	(1)	11.3	(2)	1.6
Utility:					
Capital Expenditures	16.5	(1)	17.1	(2)	(0.6)
All Other:					
Capital Expenditures	0.1	(1)	0.1	(2)	—
	$126.5		$94.6		$ 31.9

(1) At December 31, 2017, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $37.1 million, $10.7 million, $4.7 million and $3.6 million, respectively, of non-cash capital expenditures. At September 30, 2017, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $36.5 million, $25.1 million, $3.9 million and $6.7 million, respectively, of non-cash capital expenditures. The capital expenditures for the Exploration and Production segment do not include any proceeds received from the sale of oil and gas assets to IOG under the joint development agreement.

(2) At December 31, 2016, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $25.3 million, $8.7 million, $7.9 million and $7.1 million, respectively, of non-cash capital expenditures. At September 30, 2016, capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment included $25.2 million, $18.7 million, $5.3 million and $11.2 million, respectively, of non-cash capital expenditures. The capital expenditures for the Exploration and Production segment do not include any proceeds received from the sale of oil and gas assets to IOG under the joint development agreement.

Exploration and Production

The Exploration and Production segment capital expenditures for the three months ended December 31, 2017 were primarily well drilling and completion expenditures and included approximately $70.6 million for the Appalachian region (including $58.7 million in the Marcellus Shale area) and $4.1 million for the West Coast region. These amounts included approximately $40.7 million spent to develop proved undeveloped reserves.

On December 1, 2015, Seneca and IOG - CRV Marcellus, LLC (IOG), an affiliate of IOG Capital, LP, and funds managed by affiliates of Fortress Investment Group, LLC, executed a joint development agreement that allows IOG to participate in the development of certain oil and gas interests owned by Seneca in Elk, McKean and Cameron Counties, Pennsylvania. On June 13, 2016, Seneca and IOG executed an extension of the joint development agreement. Under the terms of the extended agreement, Seneca and IOG will jointly participate in a program to develop up to 75 Marcellus wells, with Seneca serving as program operator. IOG will hold an 80% working interest in all of the joint development wells. In total, IOG is expected to fund approximately $305 million for its 80% working interest in the 75 joint development wells. Of this amount, IOG has funded $267.1 million as of December 31, 2017, which includes $163.9 million of cash ($137.3 million in fiscal 2016 and $26.6 million in fiscal 2017) shown as Net Proceeds from Sale of Oil and Gas Producing Properties on the Consolidated Statements of Cash Flows for fiscal 2016 and fiscal 2017. Such proceeds from sale represent funding received from IOG for costs previously incurred by Seneca to develop a portion of the 75 joint development wells. A receivable of $17.3 million has been recorded at December 31, 2017 in recognition of additional IOG funding that is due to Seneca for costs incurred by Seneca to develop a portion of the 75 joint development wells. This receivable has been shown as a Non-Cash Investing Activity on the Consolidated Statement of Cash Flows for the quarter ended December 31, 2017. The remainder funded joint development expenditures. For further discussion of the extended joint development agreement, refer to Item 1 at Note 1 - Summary of Significant Accounting Policies under the heading “Property, Plant and Equipment.”

The Exploration and Production segment capital expenditures for the three months ended December 31, 2016 were primarily well drilling and completion expenditures and included approximately $29.8 million for the Appalachian region (including $16.4 million in the Marcellus Shale area) and $10.9 million for the West Coast region. These amounts included approximately $8.3 million spent to develop proved undeveloped reserves.

Pipeline and Storage

The Pipeline and Storage segment capital expenditures for the three months ended December 31, 2017 were partially related to additions, improvements and replacements to this segment's transmission and gas storage systems. In addition, the Pipeline and Storage segment capital expenditures for the three months ended December 31, 2017 include expenditures related to Supply Corporation's Line D Expansion Project ($12.4 million), as discussed below. The Pipeline and Storage capital expenditures for the three months ended December 31, 2016 were mainly for expenditures related to Empire and Supply Corporation's Northern Access 2016 Project ($13.5 million) and Supply Corporation's Line D Expansion Project ($4.2 million) and also included additions, improvements, and replacements to this segment's transmission and gas storage systems.

In light of the continuing demand for pipeline capacity to move natural gas from new wells being drilled in Appalachia — specifically in the Marcellus and Utica Shale producing areas — Supply Corporation and Empire have recently completed and are actively pursuing several expansion projects designed to move anticipated Marcellus and Utica production gas to other interstate pipelines and to on-system markets, and markets beyond the Supply Corporation and Empire pipeline systems. Preliminary survey and investigation costs for expansion, routine replacement or modernization projects are initially recorded as Deferred Charges on the Consolidated Balance Sheet. Management may reserve for preliminary survey and investigation costs associated with large projects by reducing the Deferred Charges balance and increasing Operation and Maintenance Expense on the Consolidated Statement of Income. If it is determined that it is highly probable that a project for which a reserve has been established will be built, the reserve is reversed. This reversal reduces Operation and Maintenance Expense and reestablishes the original balance in Deferred Charges. 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.

Supply Corporation and Empire are developing a project which would move significant prospective Marcellus production from Seneca's Western Development Area at Clermont to an Empire interconnection with TransCanada Pipeline at Chippawa and an interconnection with TGP's 200 Line in East Aurora, New York ("Northern Access 2016"). The Northern Access 2016 project would provide an outlet to Dawn-indexed markets in Canada and to the TGP line serving the U.S. Northeast. The Northern Access 2016 project involves the construction of approximately 99 miles of largely 24" pipeline and approximately 27,500 horsepower of compression on the two systems. The preliminary cost estimate for the Northern Access 2016 project is approximately $500 million. Supply Corporation, Empire and Seneca executed anchor shipper agreements for 350,000 Dth per day of firm transportation delivery capacity to Chippawa and 140,000 Dth per day of firm transportation capacity to a new interconnection with TGP's 200 Line on this project. On February 3, 2017, the Company received FERC approval of the project. On April 7, 2017, the NYDEC issued a Notice of Denial of the federal Clean Water Act Section 401 Water Quality Certification and other state stream and wetland permits for the New York portion of the project (the Water Quality Certification for the Pennsylvania portion of the project was received on January 27, 2017). On April 21, 2017, the Company appealed the NYDEC's decision with regard to the Water Quality Certification to the United States Court of Appeals for the Second Circuit, and on May 11, 2017, the Company commenced legal action in New York State Supreme Court challenging the NYDEC's actions with regard to various state permits. The Company also has pending with FERC a proceeding asserting, among other things, that the NYDEC exceeded the reasonable and statutory time frames to take action under the Clean Water Act and, therefore, waived its opportunity to approve or deny the Water Quality Certification. In light of these pending legal actions, the Company has not yet determined a target in-service date. The Company remains committed to the project. As of December 31, 2017, approximately $75.5 million has been spent on the Northern Access 2016 project, including $21.9 million that has been spent to study the project, for which no reserve has been established. The remaining $53.6 million spent on the project has been capitalized as Construction Work in Progress.

On November 21, 2014, Supply Corporation concluded an Open Season for an expansion of its Line D pipeline ("Line D Expansion") that is intended to allow growing on-system markets to avail themselves of economical gas supply on the TGP 300 line, at an existing interconnect at Lamont, Pennsylvania, and provide increased capacity into the Erie, Pennsylvania market area. Supply Corporation has executed Service Agreements for a total of 77,500 Dth per day for terms of six to ten years and services began November 1, 2017. The project involves construction of a new 4,140 horsepower Keelor Compressor Station and modifications to the Bowen compressor station at an estimated capital cost of approximately $28.2 million. The project also provides system modernization benefits. As of December 31, 2017, approximately $26.8 million has been spent on the Line D Expansion project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at December 31, 2017.

Empire concluded an Open Season on November 18, 2015, and has designed a project that would allow for the transportation of 205,000 Dth per day of additional shale supplies from interconnections in Tioga County, Pennsylvania, to TransCanada Pipeline, and the TGP 200 Line ("Empire North Project"). Empire has executed a Precedent Agreement with a foundation shipper for 150,000 Dth per day of transportation capacity and with two other shippers for 35,000 Dth per day and 5,000 Dth per day, respectively. Empire continues to negotiate precedent agreements with other prospective shippers. Empire expects to file a Section 7(c) application with the FERC in the second quarter of fiscal 2018. The Empire North project has a projected in-service date of November 1, 2019 and an estimated capital cost of approximately $140 million to $145 million. As of December 31, 2017, approximately $1.1 million has been spent to study this project, all of which has been included in Deferred Charges on the Consolidated Balance Sheet at December 31, 2017.

Supply Corporation has entered into a foundation shipper Precedent Agreement to provide incremental natural gas transportation services from Line N to the ethylene cracker facility being constructed by Shell Chemical Appalachia, LLC in Potter Township, Pennsylvania. Supply Corporation has completed an Open Season for the project and has secured incremental firm transportation capacity commitments totaling 133,000 Dth per day on Line N and on the proposed pipeline extension of approximately 4.5 miles from Line N to the facility. The proposed in-service date for this project is as early as July 1, 2019 and capital costs are expected to be $17 million. As of December 31, 2017, approximately $0.5 million has been spent to study this project, all of which has been included in Deferred Charges on the Consolidated Balance Sheet at December 31, 2017.

Gathering

The majority of the Gathering segment capital expenditures for the three months ended December 31, 2017 were for the continued buildout of Midstream Corporation's Clermont Gathering System and Midstream Corporation's Trout Run Gathering System, as discussed below. The majority of the Gathering segment capital expenditures for the three months ended December 31, 2016 were for the construction of the Clermont Gathering System.

NFG Midstream Clermont, LLC, a wholly owned subsidiary of Midstream Corporation, is building an extensive gathering system with compression in the Pennsylvania counties of McKean, Elk and Cameron. The total cost estimate for the continued buildout will be dependent on the nature and timing of the shippers', including Seneca's, long-term plans. As of December 31, 2017, approximately $285.4 million has been spent on the Clermont Gathering System, including approximately $4.0 million spent during the three months ended December 31, 2017, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at December 31, 2017.

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 48 miles of backbone and in-field gathering pipelines, two compressor stations and a dehydration and metering station. As of December 31, 2017, approximately $183.6 million has been spent on the Trout Run Gathering System, including approximately $6.3 million spent during the three months ended December 31, 2017, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at December 31, 2017.

NFG Midstream Wellsboro, LLC, a wholly owned subsidiary of Midstream Corporation, continues to develop its Wellsboro Gathering System in Tioga County, Pennsylvania. As of December 31, 2017, the Company has spent approximately $6.9 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, 2017.

Utility

The majority of the Utility segment capital expenditures for the three months ended December 31, 2017 and December 31, 2016 were made for main and service line improvements and replacements, as well as main extensions.

Project Funding

The Company has been financing the Pipeline and Storage segment and Gathering segment projects mentioned above, as well as the Exploration and Production segment capital expenditures, with cash from operations and both short and long-term borrowings. Going forward, while the Company expects to use cash on hand and cash from operations as the first means of financing these projects, the Company may issue short-term and/or long-term debt as necessary during fiscal 2018 to help meet its capital expenditures needs. The level of 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

The Company did not have any consolidated short-term debt outstanding at December 31, 2017 or September 30, 2017, nor was there any short-term debt outstanding during the quarter ended December 31, 2017. The Company continues to consider short-term debt (consisting of short-term notes payable to banks and commercial paper) an important source of cash for temporarily financing capital expenditures, gas-in-storage inventory, unrecovered purchased gas costs, margin calls on derivative financial instruments, exploration and development expenditures, other working capital needs and repayment of long-term debt. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt.

On September 9, 2016, the Company entered into a Third Amended and Restated Credit Agreement (Credit Agreement) with a syndicate of what now numbers 13 banks. This Credit Agreement provides a $750.0 million multi-year unsecured committed revolving credit facility through December 5, 2019. The Company also has a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under the uncommitted lines of credit are made at competitive market rates. The uncommitted credit lines are revocable at the option of the financial institutions and are reviewed on an annual basis. The Company anticipates that its uncommitted lines of credit generally will be renewed or substantially replaced by similar lines. The total amount available to be issued under the Company’s commercial paper program is $500.0 million. The commercial paper program is backed by the Credit Agreement, which provides that the Company's debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter from October 1, 2017 through December 5, 2019. At December 31, 2017, the Company’s debt to capitalization ratio (as calculated under the facility) was .53. The constraints specified in the Credit Agreement would have permitted an additional $1.36 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.

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

The Credit Agreement contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the Credit Agreement. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $40.0 million or more or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $40.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of December 31, 2017, the Company did not have any debt outstanding under the Credit Agreement.

None of the Company’s long-term debt at December 31, 2017 had a maturity date within the following twelve-month period. The Current Portion of Long-Term Debt at September 30, 2017 consisted of $300.0 million aggregate principal amount of 6.50% notes scheduled to mature in April 2018. The Company redeemed these notes on October

18, 2017 for $307.0 million, plus accrued interest.

The Company’s embedded cost of long-term debt was 5.17% and 5.53% at December 31, 2017 and December 31, 2016, respectively.

Under the Company’s existing indenture covenants at December 31, 2017, the Company would have been permitted to issue up to a maximum of $654.0 million in additional long-term 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 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 $98.7 million (or 4.7%) of the Company's long-term debt (as of December 31, 2017) was issued, contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

OFF-BALANCE SHEET ARRANGEMENTS

The Company has entered into certain off-balance sheet financing arrangements. These financing arrangements are primarily operating leases. The Company's consolidated subsidiaries have operating leases, the majority of which are with the Exploration and Production segment and Corporate operations, having a remaining lease commitment of approximately $27.4 million. These leases have been entered into for the use of compressors, drilling rigs, buildings 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 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, 2017, the Company contributed $27.6 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $0.7 million to its VEBA trusts for its other post-retirement benefits. In the remainder of 2018, the Company may contribute up to $5.0 million to the Retirement Plan. In the remainder of 2018, the Company expects its contributions to the VEBA trusts to be in the range of $2.0 million to $3.0 million.

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 that are designed to promote transparency, mitigate systemic risk and protect against market abuse. Although regulators have issued certain regulations, other rules that may impact the Company have yet to be finalized.

The CFTC's Dodd-Frank regulations continue to preserve the ability of non-financial end users to hedge their risks using swaps without being subject to mandatory clearing. In 2015, legislation was enacted to exempt from margin requirements swaps used by non-financial end-users to hedge or mitigate commercial risk. In 2016, the CFTC issued a reproposal to its position limit rules that would impose speculative position limits on positions in 28 core physical commodity contracts as well as economically equivalent futures, options and swaps. While the Company does not intend to enter into positions on a speculative basis, such rules could nevertheless impact the ability of the Company to enter into certain derivative hedging transactions with respect to such commodities. If we reduce our use of hedging transactions as a result of final regulations to be issued by the CFTC, our results of operations may become more volatile and our cash flows may be less predictable. There may be other rules developed by the CFTC and other regulators that could impact the Company. While many of those rules place specific conditions on the operations of swap dealers and major swap participants, concern remains that swap dealers and major swap participants will pass along their increased costs stemming from final rules through higher transaction costs and prices or other direct or indirect costs.

Finally, given the additional authority granted to the CFTC on anti-market manipulation, anti-fraud and disruptive trading practices, it is difficult to predict how the evolving enforcement priorities of the CFTC will impact our business. Should we violate any laws or regulations applicable to our hedging activities, we could be subject to CFTC enforcement action and material penalties and sanctions. The Company continues to monitor these enforcement and other regulatory developments, but cannot predict the impact that evolving application of the Dodd-Frank Act may have on its operations.

The accounting rules for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At December 31, 2017, the Company determined that nonperformance risk would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty's (assuming the derivative is in a gain position) or the Company's (assuming the derivative is in a loss position) credit default swaps rates.

For a complete discussion of market risk sensitive instruments, refer to "Market Risk Sensitive Instruments" in Item 7 of the Company's 2017 Form 10-K. There have been no subsequent material changes to the Company's exposure to market risk sensitive instruments.

Rate and Regulatory Matters

Utility Operation

Delivery rates for both the New York and Pennsylvania divisions are regulated by the states' respective public utility commissions and typically are changed only when approved through a procedure known as a "rate case." Although the Pennsylvania division does not have a rate case on file, see below for a description of the current rate proceedings affecting the New York division. In both jurisdictions, delivery rates do not reflect the recovery of purchased gas costs. Prudently-incurred gas costs are recovered through operation of automatic adjustment clauses, and are collected primarily through a separately-stated "supply charge" on the customer bill.

New York Jurisdiction

On April 28, 2016, Distribution Corporation commenced a rate case by filing proposed tariff amendments and supporting testimony requesting approval to increase its annual revenues by approximately $41.7 million. Distribution Corporation explained in the filing that its request for rate relief was necessitated by a revenue requirement driven primarily by rate base growth, higher operating expense and higher depreciation expense, among other things. On January 23, 2017, the administrative law judge assigned to the proceeding issued a recommended decision (RD) in the case. The RD, as revised on January 26, 2017, recommended a rate increase designed to provide additional annual revenues of $8.5 million, an equity ratio, subject to update of 42.3% based on the Company's equity ratio, and a cost of equity, subject to update of 8.6%. On April 20, 2017, the NYPSC issued an Order adopting some provisions of the RD and modifying or rejecting others. The Order provides for an annual rate increase of $5.9 million. The rate increase became effective May 1, 2017. The Order further provides for a return on equity of 8.7%, and established an equity ratio of 42.9%. The Order also directs the implementation of an earnings sharing mechanism to be in place beginning on April 1, 2018.

On July 28, 2017, Distribution Corporation filed an appeal with New York State Supreme Court, Albany County, seeking review of the Order. The appeal contends that portions of the Order should be invalidated because they fail to meet the applicable legal standard for agency decisions. On December 11, 2017, the appeal was transferred to the Supreme Court, Appellate Division, Third Department. The Company cannot predict the outcome of the appeal at this time.

On December 22, 2017, the federal Tax Cuts and Jobs Act (the 2017 Tax Reform Act) was enacted into law. On December 29, 2017, the NYPSC issued an order instituting a proceeding to study the potential effects of the enactment of the 2017 Tax Reform Act on the tax expenses and liabilities of New York utilities, and the "regulatory treatment of any windfalls resulting from same in order to preserve the benefits for ratepayers." In its order, the NYPSC stated that the effect of the 2017 Tax Reform Act on utilities' taxation is likely to be material and complex and that the proceeding was needed to begin the process of addressing the impact on the State’s utilities and ratepayers. The order establishes that the first steps in such process will be soliciting information from its regulated utilities to quantify the impact of the 2017 Tax Reform Act, scheduling a technical conference with the utilities, and the issuance of a NY Department of Public Service Staff (Staff) proposal for accounting and ratemaking treatment of the tax changes. The order further states that once Staff’s proposal is issued, utilities and other interested parties will be invited to comment on Staff’s recommendation. The order also declares that utilities are “put on notice that it is the [NYPSC]’s intent to ensure that net benefits accruing from the Tax Act are preserved for ratepayers, either through deferral accounting or another method, from the first day the Tax Act is put into effect. Utilities acting contrary to this intent do so at their own risk.” The Company cannot predict the outcome of this proceeding at this time. Refer to Item 1 at Note 4 - Income Taxes for a further discussion of the 2017 Tax Reform Act.

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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 has no active rate case on file. Supply Corporation's current rate settlement requires a rate case filing no later than December 31, 2019.

Empire currently has no active rate case on file. Empire’s current rate settlement requires a rate case filing no later than July 1, 2021.

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. The EPA previously adopted final regulations that set methane and volatile organic compound emissions standards for new or modified oil and gas emissions sources. These rules impose more stringent leak detection and repair requirements, and further address reporting and control of methane and volatile organic compound emissions. The current administration has issued executive orders to review and potentially roll back many of these regulations, and, in turn, litigation (not involving the Company) has been instituted to challenge the administration's efforts. The Company must continue to comply with all applicable regulations. 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. A number of states have adopted energy strategies or plans with goals that include the reduction of greenhouse gas emissions. For example, New York’s State Energy Plan includes Reforming the Energy Vision (REV) initiatives which set greenhouse gas emission reduction targets of 40% by 2030 and 80% by 2050. Additionally, the Plan targets that 50% of electric generation must come from renewable energy sources by 2030. Similarly, Pennsylvania has a methane reduction framework for the oil and gas industry which will result in permitting changes with the stated goal of reducing methane emissions from well sites, compressor stations and pipelines. With respect to its operations in California, the Company currently complies with California cap-and-trade guidelines, which increases the Company's cost of environmental compliance in its Exploration and Production segment operations. Legislation or regulation that aims to reduce greenhouse gas emissions could also include carbon taxes, restrictive permitting, increased efficiency standards, and incentives or mandates to conserve energy or use renewable energy sources. Federal, state or local governments may, for example, provide tax advantages and other subsidies to support alternative energy sources, mandate the use of specific fuels or technologies, or promote research into new technologies to reduce the cost and increase the scalability of alternative energy sources. These climate change and greenhouse gas initiatives could increase the Company's cost of environmental compliance by requiring the Company to retrofit existing equipment, install new equipment to reduce emissions from larger facilities and/or purchase emission allowances. They could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard to existing and new facilities, impose additional monitoring and reporting requirements, and reduce demand for oil and natural gas. But legislation or regulation that sets a price on or otherwise restricts carbon emissions could also benefit the Company by increasing demand for natural gas, because substantially fewer carbon emissions per Btu of heat generated are associated with the use of natural gas than with certain alternate fuels such as coal and oil. The effect (material or not) on the Company of any new legislative or regulatory measures will depend on the particular provisions that are ultimately adopted.

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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. 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;
2. 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;
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. Impairments under the SEC’s full cost ceiling test for natural gas and oil reserves;
5. Changes in the price of natural gas or oil;
6. 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;
7. 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;

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

9. Changes in price differentials 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;

10. Other changes in price differentials between similar quantities of natural gas or oil having different quality, heating value, hydrocarbon mix or delivery date;

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11. The cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company;
12. Uncertainty of oil and gas reserve estimates;
13. Significant differences between the Company's projected and actual production levels for natural gas or oil;
14. Changes in demographic patterns and weather conditions;
15. Changes in the availability, price or accounting treatment of derivative financial instruments;
16. 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;
17. 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;
18. The creditworthiness or performance of the Company's key suppliers, customers and counterparties;
19. Economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities, acts of war, cyber attacks or pest infestation;
20. Significant differences between the Company's projected and actual capital expenditures and operating expenses; 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, 2017.

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, 2017 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

On September 13, 2017, the PaDEP sent a draft Consent Assessment of Civil Penalty (CACP) to Seneca, in relation to an alleged violation of the Pennsylvania Oil and Gas Act, as well as PaDEP rules and regulations regarding gas migration relating to Seneca's drilling activities. The amount of the penalty sought by the PaDEP is not material to the Company. The draft CACP

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alleges a violation identified by the PaDEP in 2011. Seneca disputes the alleged violation and will vigorously defend its position in negotiations with the PaDEP.

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 2017 Form 10-K have not materially changed other than as set forth below. The risk factor presented below supersedes the risk factor having the same caption in the 2017 Form 10-K and should otherwise be read in conjunction with all of the risk factors disclosed in the 2017 Form 10-K.

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

While the Company generally refers to its Utility segment and its Pipeline and Storage segment as its "regulated segments," there are many governmental laws and regulations that have an impact on almost every aspect of the Company's businesses including, but not limited to, tax law, such as the 2017 Tax Reform Act and related regulatory action, and environmental law. Existing statutes and regulations may be revised or reinterpreted and new laws and regulations may be adopted or become applicable to the Company, such as tax legislation, which may increase the Company's costs, require refunds to customers or affect its business in ways that the Company cannot predict. Administrative agencies may apply existing laws and regulations in unanticipated, inconsistent or legally unsupportable ways, making it difficult to develop and complete projects, and harming the economic climate generally. New York State, for example, under the current executive administration, appears intent on imposing unattainable regulatory standards, at least with respect to certain fossil fuel energy infrastructure projects.

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

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

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

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

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

The Company is also subject to the jurisdiction of the Pipeline and Hazardous Materials Safety Administration (PHMSA). PHMSA issues regulations and conducts evaluations, among other things, that set safety standards for pipelines and underground storage facilities. Compliance with new legislation could increase costs to the Company. Non-compliance with this legislation could result in civil penalties for pipeline safety violations. If as a result of these or similar new laws or regulations the Company incurs material costs that it is unable to recover fully through rates or otherwise offset, the Company's financial condition, results of operations, and cash flows could be adversely affected.

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

The Company has significant transactions involving price hedging of its oil and natural gas production as well as its fixed price purchase and sale commitments.

In order to protect itself to some extent against unusual price volatility and to lock in fixed pricing on oil and natural gas production for certain periods of time, the Company’s Exploration and Production segment regularly enters into commodity price derivatives contracts (hedging arrangements) with respect to a portion of its expected production. These contracts may at any time cover as much as approximately 80% of the Company’s expected energy production during the upcoming 12-month period. These contracts reduce exposure to subsequent price drops but can also limit the Company’s ability to benefit from increases in commodity prices. In addition, the Energy Marketing segment enters into certain hedging arrangements, primarily with respect to its fixed price purchase and sales commitments and its gas stored underground.

Under applicable accounting rules currently in effect, the Company’s hedging arrangements are subject to quarterly effectiveness tests. Inherent within those effectiveness tests are assumptions concerning the long-term price differential between different types of crude oil, assumptions concerning the difference between published natural gas price indexes established by pipelines into which hedged natural gas production is delivered and the reference price established in the hedging arrangements, assumptions regarding the levels of production that will be achieved and, with regard to fixed price commitments, assumptions regarding the creditworthiness of certain customers and their forecasted consumption of natural gas. Depending on market conditions for natural gas and crude oil and the levels of production actually achieved, it is possible that certain of those assumptions may change in the future, and, depending

on the magnitude of any such changes, it is possible that a portion of the Company's hedges may no longer be considered highly effective. In that case, gains or losses from the ineffective derivative financial instruments would be marked-to-market on the income statement without regard to an underlying physical transaction. For example, in the Exploration and Production segment, where the Company uses short positions (i.e. positions that pay off in the event of commodity price decline) to hedge forecasted sales, gains would occur to the extent that natural gas and crude oil hedge prices exceed market prices for the Company's natural gas and crude oil production, and losses would occur to the extent that market prices for the Company's natural gas and crude oil production exceed hedge prices.
Use of energy commodity price hedges also exposes the Company to the risk of non-performance by a contract counterparty. These parties might not be able to perform their obligations under the hedge arrangements. In addition, the Company enters into certain commodity price hedges that are cleared through the NYMEX or ICE by futures commission merchants. Under

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NYMEX and ICE rules, the Company is required to post collateral in connection with such hedges, with such collateral being held by its futures commission merchants. The Company is exposed to the risk of loss of such collateral from occurrences such as financial failure of its futures commission merchants, or misappropriation or mishandling of clients' funds or other similar actions by its futures commission merchants. In addition, the Company is exposed to potential hedging ineffectiveness in the event of a failure by one of its futures commission merchants or contract counterparties.

It is the Company's practice that the use of commodity derivatives contracts comply with various policies in effect in respective business segments. For example, in the Exploration and Production segment, commodity derivatives contracts must be confined to the price hedging of existing and forecast production, and in the Energy Marketing segment, commodity derivatives with respect to fixed price purchase and sales commitments must be matched against commitments reasonably certain to be fulfilled. The Company maintains a system of internal controls to monitor compliance with its policy. However, unauthorized speculative trades, if they were to occur, could expose the Company to substantial losses to cover positions in its derivatives contracts. In addition, in the event the Company's actual production of oil and natural gas falls short of hedged forecast production, the Company may incur substantial losses to cover its hedges.

The Dodd-Frank Act increased federal oversight and regulation of the over-the-counter derivatives markets and certain entities that participate in those markets. The act requires the CFTC, the SEC and various banking regulators to promulgate rules and regulations implementing the act. Although regulators have issued certain regulations, other rules that may be relevant to the Company have yet to be finalized.

The CFTC's Dodd-Frank regulations continue to preserve the ability of non-financial end users to hedge their risks using swaps without being subject to mandatory clearing. In 2015, legislation was enacted to exempt from margin requirements swaps used by non-financial end users to hedge or mitigate commercial risk. In 2016, the CFTC issued a reproposal to its position limit rules that would impose speculative position limits on positions in 28 core physical commodity contracts as well as economically equivalent futures, options and swaps. While the Company does not intend to enter into positions on a speculative basis, such rules could nevertheless impact the ability of the Company to enter into certain derivative hedging transactions with respect to such commodities. If the Company reduces its use of hedging transactions as a result of final CFTC regulations, the Company's results of operations may become more volatile and its cash flows may be less predictable. There may be other rules developed by the CFTC and other regulators that could impact the Company. While many of those rules place specific conditions on the operations of swap dealers and major swap participants, concern remains that swap dealers and major swap participants will pass along their increased costs stemming from final rules through higher transaction costs and prices or other direct or indirect costs.

Finally, given the additional authority granted to the CFTC on anti-market manipulation, anti-fraud and disruptive trading practices, it is difficult to predict how the evolving enforcement priorities of the CFTC will impact the Company's business. Should the Company violate any laws or regulations applicable to the Company's hedging activities, the Company could be subject to CFTC enforcement action and material penalties and sanctions.

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

On October 2, 2017, the Company issued a total of 6,912 unregistered shares of Company common stock to nine non-employee directors of the Company then serving on the Board of Directors of the Company, 768 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, 2017. These transactions were exempt from registration under Section 4(a)(2) of the Securities Act of 1933, as transactions not involving a public offering.

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Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased (a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Share Repurchase Plans or Programs	Maximum Number of Shares That May Yet Be Purchased Under Share Repurchase Plans or Programs (b)
Oct. 1 - 31, 2017	—	N/A	—	6,971,019
Nov. 1 - 30, 2017	7,336	$57.83	—	6,971,019
Dec. 1 - 31, 2017	43,882	$57.06	—	6,971,019
Total	51,218	$57.17	—	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, 2017, 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 has not repurchased any shares since September 17, 2008 and has no plans to make further purchases in the near future.

Item 6. Exhibits

Exhibit Number	Description of Exhibit
10.1	Form of Award Notice for Return on Capital Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan.
10.2	Form of Award Notice for Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan.
10.3	Form of Award Notice for Restricted Stock Units under the National Fuel Gas Company 2010 Equity Compensation Plan.
12	Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the Three Months Ended December 31, 2017 and the Fiscal Years Ended September 30, 2014 through 2017.
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, 2017 and 2016.
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, 2017 and 2016, (ii) the

Consolidated Statements of Comprehensive Income for the three months ended December 31, 2017 and 2016, (iii) the Consolidated Balance Sheets at December 31, 2017 and September 30, 2017, (iv) the Consolidated Statements of Cash Flows for the three months ended December 31, 2017 and 2016 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.

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SIGNATURES

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

NATIONAL FUEL GAS COMPANY
(Registrant)

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

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

Date: February 2, 2018