UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

☑ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the Fiscal Year Ended September 30, 2018

☐ 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

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on Which Registered
Common Stock, par value $1.00 per share, and Common Stock Purchase Rights	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15 (d) of the Act. Yes ☐ No ☑

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 ☑ No ☐

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted 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 such files). Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a 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 ☑	Accelerated filer ☐
Non-accelerated filer ☐	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 Act). Yes ☐ No ☑

The aggregate market value of the voting stock held by nonaffiliates of the registrant amounted to $4,333,193,000 as of March 31, 2018.

Common Stock, par value $1.00 per share, outstanding as of October 31, 2018: 85,963,834 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for its 2019 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission within 120 days of September 30, 2018, are incorporated by reference into Part III of this report.

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 Company National Fuel Gas Midstream Company, LLC (formerly National Fuel Gas Midstream Corporation) *

National Fuel National Fuel Gas Company

NFR National Fuel Resources, Inc.

Registrant National Fuel Gas Company

Seneca Seneca Resources Company, LLC (formerly Seneca Resources Corporation) *

Supply Corporation National Fuel Gas Supply Corporation

* Effective August 1, 2018, the Company converted Seneca Resources Corporation and National Fuel Gas Midstream Corporation to limited liability companies (LLCs) for tax purposes. Both LLCs are wholly owned by a newly formed subsidiary named Pennsylvania Gas Holdings Corporation which in turn is wholly owned by the Company.

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

PHMSA Pipeline and Hazardous Materials Safety Administration

SEC Securities and Exchange Commission

Other

2017 Tax Reform Act Tax legislation referred to as the "Tax Cuts and Jobs Act," enacted December 22, 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 pays Supply Corporation and/or Empire for gas the customer receives in excess of amounts delivered into Supply Corporation's and Empire's systems by the customer's shipper.

Degree day A measure of the coldness of the weather experienced, based on the extent to which the daily average temperature falls below a reference temperature, usually 65 degrees Fahrenheit.

Derivative A financial instrument or other contract, the terms of which include an underlying variable (a price, interest rate, index rate, exchange rate, or other variable) and a notional amount (number of units, barrels, cubic feet, etc.). The terms also permit for the instrument or contract to be settled net and no initial net investment is required to enter into the financial instrument or contract. Examples include futures contracts, options, no cost collars and swaps.

Development costs Costs incurred to obtain access to proved oil and gas reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas.

Development well A well drilled to a known producing formation in a previously discovered field.

Dodd-Frank Act Dodd-Frank Wall Street Reform and Consumer Protection Act.

Dth Decatherm; one Dth of natural gas has a heating value of 1,000,000 British thermal units, approximately equal to the heating value of 1 Mcf of natural gas.

Exchange Act Securities Exchange Act of 1934, as amended

Expenditures for long-lived assets Includes capital expenditures, stock acquisitions and/or investments in partnerships.

Exploitation Development of a field, including the location, drilling, completion and equipment of wells necessary to produce the commercially recoverable oil and gas in the field.

Exploration costs Costs incurred in identifying areas that may warrant examination, as well as costs incurred in examining specific areas, including drilling exploratory wells.

FERC 7(c) application An application to the FERC under Section 7(c) of the federal Natural Gas Act for authority to construct, operate (and provide services through) facilities to transport or store natural gas in interstate commerce.

Exploratory well A well drilled in unproven or semi-proven territory for the purpose of ascertaining the presence underground of a commercial hydrocarbon deposit.

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 dekatherm of natural gas)

MMcf Million cubic feet (of natural gas)

MMcfe Million cubic feet equivalent

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.
PCB Polychlorinated Biphenyl
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 those reserves productive.
PRP Potentially responsible party
Reliable technology Technology that a company may use to establish reserves estimates and categories that has been proven empirically to lead to correct conclusions.
Reserves The unproduced but recoverable oil and/or gas in place in a formation which has been proven by production.
Restructuring Generally referring to partial "deregulation" of the pipeline and/or utility industry by statutory or regulatory process. Restructuring of federally regulated natural gas pipelines resulted in the separation (or "unbundling") of gas commodity service from transportation service for wholesale and large-volume retail markets. State restructuring programs attempt to extend the same process to retail mass markets.
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 Ratings 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.
Spot gas purchases The purchase of natural gas on a short-term basis.
Stock acquisitions Investments in corporations.
Unbundled service A service that has been separated from other services, with rates charged that reflect only the cost of the separated service.
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.

For the Fiscal Year Ended September 30, 2018

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PART I

Item 1 *Business*

The Company and its Subsidiaries

National Fuel Gas Company (the Registrant), incorporated in 1902, is a holding company organized under the laws of the State of New Jersey. Except as otherwise indicated below, the Registrant owns directly or indirectly all of the outstanding securities of its subsidiaries. Reference to "the Company" in this report means the Registrant, the Registrant and its subsidiaries or the Registrant's subsidiaries as appropriate in the context of the disclosure. Also, all references to a certain year in this report relate to the Company's fiscal year ended September 30 of that year unless otherwise noted.

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 used for, and benefiting from, the production and transportation of natural gas from the Appalachian basin. Current development activities are focused in the Marcellus and Utica Shales, geological shale formations that are present nearly a mile or more below the surface in the Appalachian region of the United States. 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 also develops and produces oil reserves, primarily in California. The Company reports financial results for five business segments: Exploration and Production, Pipeline and Storage, Gathering, Utility, and Energy Marketing.

1. The Exploration and Production segment operations are carried out by Seneca Resources Company, LLC (Seneca), a Pennsylvania limited liability company. Seneca is engaged in the exploration for, and the development and production of, natural gas and oil reserves in California and in the Appalachian region of the United States. At September 30, 2018, Seneca had U.S. proved developed and undeveloped reserves of 27,663 Mbbl of oil and 2,357,342 MMcf of natural gas.

2. The Pipeline and Storage segment operations are carried out by National Fuel Gas Supply Corporation (Supply Corporation), a Pennsylvania corporation, and Empire Pipeline, Inc. (Empire), a New York corporation. Supply Corporation provides interstate natural gas transportation and storage services for affiliated and nonaffiliated companies through (i) an integrated gas pipeline system extending from southwestern Pennsylvania to the New York-Canadian border at the Niagara River and eastward to Ellisburg and Leidy, Pennsylvania, and (ii) 28 underground natural gas storage fields owned and operated by Supply Corporation as well as three other underground natural gas storage fields owned and operated jointly with other interstate gas pipeline companies. Empire transports and stores natural gas for major industrial companies, utilities (including Distribution Corporation) and power producers in New York State. Empire also transports natural gas for natural gas marketers along with exploration and production companies from natural gas producing areas in Pennsylvania to markets in New York and to interstate pipeline delivery points for additional markets in the northeastern United States and Canada. Empire owns the Empire Pipeline, a 266-mile pipeline system comprising four principal components: a 157-mile pipeline that extends from the United States/Canadian border at the Niagara River near Buffalo, New York to near Syracuse, New York; a 77-mile pipeline extension from near Rochester, New York to an interconnection with the unaffiliated Millennium Pipeline near Corning, New York (the Empire Connector), a 15-mile pipeline extension from Corning into Tioga County, Pennsylvania (the Tioga County Extension) and a 17-mile pipeline extension between Empire's pipeline system and Supply Corporation's system at Tuscarora, New York.

3. The Gathering segment operations are carried out by wholly-owned subsidiaries of National Fuel Gas Midstream Company, LLC (Midstream Company), a Pennsylvania limited liability company. Through these subsidiaries, Midstream Company builds, owns and operates natural gas processing and pipeline gathering facilities in the Appalachian region.

4. The Utility segment operations are carried out by National Fuel Gas Distribution Corporation (Distribution Corporation), a New York corporation. Distribution Corporation sells natural gas or provides natural gas

transportation services to approximately 750,200 customers through a local distribution system located in western New York and northwestern Pennsylvania. The principal metropolitan areas served by Distribution Corporation include Buffalo, Niagara Falls and Jamestown, New York and Erie and Sharon, Pennsylvania.

5. The Energy Marketing segment operations are carried out by National Fuel Resources, Inc. (NFR), a New York corporation, which markets natural gas to industrial, wholesale, commercial, public authority and residential customers primarily in western and central New York and northwestern Pennsylvania, offering competitively priced natural gas for its customers.

Financial information about each of the Company’s business segments can be found in Item 7, MD&A and also in Item 8 at Note J — Business Segment Information.

Seneca’s Northeast Division is included in the Company's All Other Category. This division markets timber from Appalachian land holdings. At September 30, 2018, the Company owned approximately 94,000 acres of timber property and managed approximately 3,000 additional acres of timber cutting rights.

No single customer, or group of customers under common control, accounted for more than 10% of the Company’s consolidated revenues in 2018.

Rates and Regulation

The Utility segment’s rates, services and other matters are regulated by the NYPSC with respect to services provided within New York and by the PaPUC with respect to services provided within Pennsylvania. For additional discussion of the Utility segment’s rates and regulation, see Item 7, MD&A under the heading “Rate and Regulatory Matters” and Item 8 at Note A — Summary of Significant Accounting Policies (Regulatory Mechanisms) and Note C — Regulatory Matters.

The Pipeline and Storage segment’s rates, services and other matters are regulated by the FERC. For additional discussion of the Pipeline and Storage segment’s rates and regulation, see Item 7, MD&A under the heading “Rate and Regulatory Matters” and Item 8 at Note A — Summary of Significant Accounting Policies (Regulatory Mechanisms) and Note C — Regulatory Matters.

The discussion under Item 8 at Note C — Regulatory Matters includes a description of the regulatory assets and liabilities reflected on the Company’s Consolidated Balance Sheets in accordance with applicable accounting standards. To the extent that the criteria set forth in such accounting standards are not met by the operations of the Utility segment or the Pipeline and Storage segment, as the case may be, the related regulatory assets and liabilities would be eliminated from the Company’s Consolidated Balance Sheets and such accounting treatment would be discontinued.

In addition, the Company and its subsidiaries are subject to the same federal, state and local regulations on various subjects, including environmental matters, to which other companies doing similar business in the same locations are subject.

The Exploration and Production Segment

The Exploration and Production segment contributed approximately 46.1% of the Company's 2018 net income available for common stock.

Additional discussion of the Exploration and Production segment appears below in this Item 1 under the headings “Sources and Availability of Raw Materials” and “Competition: The Exploration and Production Segment,” in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The Pipeline and Storage Segment

The Pipeline and Storage segment contributed approximately 24.8% of the Company's 2018 net income available for common stock.

Supply Corporation’s firm transportation capacity is subject to change as the market identifies different transportation paths and receipt/delivery point combinations. At the end of fiscal year 2018, Supply Corporation had firm transportation service agreements and leases for approximately 3,187 MDth per day (contracted transportation capacity). The Utility segment accounts for approximately 1,124 MDth per day or 35% of contracted transportation capacity, and the Energy Marketing and Exploration and Production segments represent another 165 MDth per day or 5%. Additionally, Supply Corporation leases 55 MDth per day or 2% of its firm transportation capacity to Empire. The remaining 1,843 MDth or 58% is subject to firm contracts or leases with nonaffiliated customers. Contracted transportation capacity with both affiliated and nonaffiliated shippers is expected to remain relatively constant in fiscal 2019.

Supply Corporation had service agreements and leases for all of its firm storage capacity, totaling 71,938 MDth, at the end of 2018. The Utility segment has contracted for 28,491 MDth or 40% of the total firm storage capacity, and the Energy Marketing segment accounts for another 2,644 MDth or 4%. Additionally, Supply Corporation leases 3,753 MDth or 5% of its firm storage capacity to Empire. Nonaffiliated customers have contracted for the remaining 37,050 MDth or 51%. Supply Corporation expects several contracted storage services to terminate and be remarketed in fiscal 2019 totaling approximately 2,000 MDth.

At the end of fiscal 2018, Empire had service agreements in place for firm transportation capacity totaling up to approximately 978 MDth per day, with 95% of that capacity contracted as long-term, full-year deals. The Utility segment accounted for 4% of Empire's firm contracted capacity, with the remaining 96% subject to contracts with nonaffiliated customers. Empire expects several contracted firm transportation services to terminate and be remarketed in fiscal 2019 totaling approximately 153 MDth per day.

Empire's firm storage capacity, totaling 3,753 MDth, was fully contracted at the end of fiscal 2018. The total storage capacity is contracted on a long-term basis, with a nonaffiliated customer. The contract will not expire or terminate in fiscal 2019.

The majority of Supply Corporation's transportation and storage contracts, and the majority of Empire's transportation contracts, allow either party to terminate the contract upon six or twelve months' notice effective at the end of the primary term, and include "evergreen" language that allows for annual term extension(s). Empire's storage contract contains similar termination and "evergreen" language.

Additional discussion of the Pipeline and Storage segment appears below under the headings "Sources and Availability of Raw Materials," "Competition: The Pipeline and Storage Segment" and "Seasonality," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The Gathering Segment

The Gathering segment contributed approximately 21.3% of the Company's 2018 net income available for common stock.

Additional discussion of the Gathering segment appears below under the headings "Sources and Availability of Raw Materials" and "Competition: The Gathering Segment," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The Utility Segment

The Utility segment contributed approximately 13.1% of the Company's 2018 net income available for common stock.

Additional discussion of the Utility segment appears below under the headings "Sources and Availability of Raw Materials," "Competition: The Utility Segment" and "Seasonality," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

The Energy Marketing Segment

The Energy Marketing segment contributed approximately 0.1% of the Company's 2018 net income available for common stock.

Additional discussion of the Energy Marketing segment appears below under the headings "Sources and Availability of Raw Materials," "Competition: The Energy Marketing Segment" and "Seasonality," in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

All Other Category and Corporate Operations

The All Other category and Corporate operations incurred a net loss in 2018. The impact of this net loss in relation to the Company's 2018 net income available for common stock was negative 5.4%.

Additional discussion of the All Other category and Corporate operations appears below in Item 7, MD&A and in Item 8, Financial Statements and Supplementary Data.

Sources and Availability of Raw Materials

The Exploration and Production segment seeks to discover and produce raw materials (natural gas, oil and hydrocarbon liquids) as further described in this report in Item 7, MD&A and Item 8 at Note J — Business Segment Information and Note L — Supplementary Information for Oil and Gas Producing Activities.

The Pipeline and Storage segment transports and stores natural gas owned by its customers, whose gas originates in the southwestern, mid-continent and Appalachian regions of the United States as well as in Canada. Additional discussion of proposed pipeline projects appears below under "Competition: The Pipeline and Storage Segment" and in Item 7, MD&A.

The Gathering segment gathers, processes and transports natural gas that is produced by Seneca in the Appalachian region of the United States. Additional discussion of proposed gathering projects appears below in Item 7, MD&A.

Natural gas is the principal raw material for the Utility segment. In 2018, the Utility segment purchased 74.5 Bcf of gas (including 70.0 Bcf for delivery to retail customers, 0.1 Bcf for off-system sales and 4.4 Bcf used in operations). Gas purchased from producers and suppliers in the United States under firm contracts (seasonal and longer) accounted for 52% of these purchases. Purchases of gas on the spot market (contracts of one month or less) accounted for 48% of the Utility segment's 2018 purchases. Purchases from DTE Energy Trading, Inc. (31%), NextEra Energy Marketing, LLC (12%), SWN Energy Services Company, LLC (11%), South Jersey Resources Group, LLC (10%), Shell Energy North America US (7%) and Direct Energy Business Marketing (5%) accounted for 76% of the Utility's 2018 gas purchases. No other producer or supplier provided the Utility segment with more than 5% of its gas requirements in 2018.

The Energy Marketing segment depends on an adequate supply of natural gas to deliver to its customers. In 2018, this segment purchased 42.8 Bcf of gas, including 42.3 Bcf for delivery to its customers. The remaining 0.5 Bcf largely represents gas used in operations. The gas purchased by the Energy Marketing segment originates primarily in either the Appalachian or mid-continent regions of the United States.

Competition

Competition in the natural gas industry exists among providers of natural gas, as well as between natural gas and other sources of energy, such as fuel oil and electricity. Management believes that the environmental advantages of natural gas have enhanced its competitive position relative to other fuels.

The Company competes on the basis of price, service and reliability, product performance and other factors. Sources and providers of energy, other than those described under this "Competition" heading, do not compete with the Company to any significant extent.

Competition: The Exploration and Production Segment

The Exploration and Production segment competes with other oil and natural gas producers and marketers with respect to sales of oil and natural gas. The Exploration and Production segment also competes, by competitive bidding and otherwise, with other oil and natural gas producers with respect to exploration and development prospects and mineral leaseholds.

To compete in this environment, Seneca originates and acts as operator on its prospects, seeks to minimize the risk of exploratory efforts through partnership-type arrangements, utilizes technology for both exploratory studies and drilling operations, and seeks market niches based on size, operating expertise and financial criteria.

Competition: The Pipeline and Storage Segment

Supply Corporation competes for market growth in the natural gas market with other pipeline companies transporting gas in the northeast United States and with other companies providing gas storage services. Supply Corporation has some unique characteristics which enhance its competitive position, as described below. Most of Supply Corporation's facilities are in or near areas overlying the Marcellus and Utica Shale production areas in Pennsylvania, and it has established interconnections with producers and other pipelines to access these supplies. Its facilities are also located adjacent to the Canadian border at the Niagara River providing access to markets in Canada and, through TransCanada Pipeline, to markets in the northeastern and midwestern United States. Supply Corporation has developed and placed into service a number of pipeline expansion projects to transport natural gas to key markets within New York and Pennsylvania, the northeastern United States, Canada, and most recently to long-haul pipelines moving gas into the U.S. Midwest and even back to the gulf coast. For further discussion of Pipeline and Storage projects, refer to Item 7, MD&A under the headings "Investing Cash Flow."

Empire competes for market growth in the natural gas market with other pipeline companies transporting gas in the northeast United States and upstate New York in particular. Empire is well situated to provide transportation of Appalachian-sourced gas as well as gas received at the Niagara River at Chippawa. Empire's location provides it the opportunity to compete for an increased share of the gas transportation markets both for delivery to the New York and Northeast markets and from and into Canada. The Empire Connector and other projects expanded Empire's natural gas pipeline and enables Empire to serve new markets in New York and elsewhere in the Northeast, and to attach to prolific Marcellus and Utica supplies principally from Tioga and Bradford Counties in Pennsylvania. Like Supply Corporation, Empire's expanded system facilitates transportation of Marcellus Shale gas to key markets within New York State, the northeastern United States and Canada.

Competition: The Gathering Segment

The Gathering segment provides gathering services for Seneca's production and competes with other companies that gather and process natural gas in the Appalachian region.

Competition: The Utility Segment

With respect to gas commodity service, in New York and Pennsylvania, both of which have implemented "unbundling" policies that allow customers to choose their gas commodity supplier, Distribution Corporation has retained a substantial majority of small sales customers. In New York, approximately 17%, and in Pennsylvania, approximately 14%, of Distribution Corporation's small-volume residential and commercial customers purchase their supplies from unregulated marketers. In contrast, almost all large-volume load is served by unregulated retail marketers. However, retail competition for gas commodity service does not pose an acute competitive threat for Distribution Corporation, because in both jurisdictions, utility cost of service is recovered through rates and charges for gas delivery service, not gas commodity service.

Competition for transportation service to large-volume customers continues with local producers or pipeline companies attempting to sell or transport gas directly to end-users located within the Utility segment's service territories without use of the utility's facilities (i.e., bypass). In addition, while competition with fuel oil suppliers exists, recent commodity pricing has enhanced the competitive position of natural gas.

The Utility segment competes in its most vulnerable markets (the large commercial and industrial markets) by offering unbundled, flexible, high quality services. The Utility segment continues to develop programs promoting new uses of natural gas.

Competition: The Energy Marketing Segment

The Energy Marketing segment competes with other marketers of natural gas and with other providers of energy supply. Competition in this area is well developed with regard to price and services from local, regional and national marketers.

Seasonality

Variations in weather conditions can materially affect the volume of natural gas delivered by the Utility segment, as virtually all of its residential and commercial customers use natural gas for space heating. The effect that this has on Utility segment margins in New York is mitigated by a WNC, which covers the eight-month period from October through May. Weather that is warmer than normal results in an upward adjustment to customers' current bills, while weather that is colder than normal results in a downward adjustment, so that in either case projected operating costs calculated at normal temperatures will be recovered.

Volumes transported and stored by Supply Corporation and volumes transported by Empire may vary materially depending on weather, without materially affecting the revenues of those companies. Supply Corporation's and Empire's allowed rates are based on a straight fixed-variable rate design which allows recovery of fixed costs in fixed monthly reservation charges. Variable charges based on volumes are designed to recover only the variable costs associated with actual transportation or storage of gas.

Variations in weather conditions materially affect the volume of gas consumed by customers of the Energy Marketing segment. Volume variations have a corresponding impact on revenues within this segment.

Capital Expenditures

A discussion of capital expenditures by business segment is included in Item 7, MD&A under the heading "Investing Cash Flow."

Environmental Matters

A discussion of material environmental matters involving the Company is included in Item 7, MD&A under the heading "Environmental Matters" and in Item 8, Note I — Commitments and Contingencies.

Miscellaneous

The Company and its wholly owned or majority-owned subsidiaries had a total of 2,105 full-time employees at September 30, 2018.

The Company has agreements in place with collective bargaining units in New York and Pennsylvania. Agreements covering employees in collective bargaining units in New York are scheduled to expire in February 2021. Agreements covering employees in collective bargaining units in Pennsylvania are scheduled to expire in April 2022.

The Utility segment has numerous municipal franchises under which it uses public roads and certain other rights-of-way and public property for the location of facilities. When necessary, the Utility segment renews such franchises.

The Company makes its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K, and any amendments to those reports, available free of charge on the Company's internet website, www.nationalfuelgas.com, as soon as reasonably practicable after they are electronically filed with or furnished to the SEC. The information available at the Company's internet website is not part of this Form 10-K or any other report filed with or furnished to the SEC.

Executive Officers of the Company as of November 15, 2018(1)

Name and Age (as of November 15, 2018)	Current Company Positions and Other Material Business Experience During Past Five Years
Ronald J. Tanski (66)	Chief Executive Officer of the Company since April 2013 and President of the Company since July 2010.
John R. Pustulka (66)	Chief Operating Officer of the Company since February 2016. Mr. Pustulka previously served as President of Supply Corporation from July 2010 through January 2016.
David P. Bauer (49)	President of Supply Corporation since February 2016. Treasurer and Principal Financial Officer of the Company since July 2010. Treasurer of Seneca since April 2015; Treasurer of Distribution Corporation since April 2015; Treasurer of Midstream Company since April 2013; Treasurer of Supply Corporation since June 2007; and Treasurer of Empire since June 2007. Mr. Bauer previously served as Assistant Treasurer of Distribution Corporation from April 2004 through March 2015.
Carl M. Carlotti (63)	President of Distribution Corporation since February 2016. Mr. Carlotti previously served as Senior Vice President of Distribution Corporation from January 2008 through January 2016.
Ronald C. Kraemer (62)	President of Empire since August 2008 and Senior Vice President of Supply Corporation since June 2016. Mr. Kraemer previously served as Vice President of Supply Corporation from August 2008 through May 2016.
John P. McGinnis (58)	President of Seneca since May 2016. Mr. McGinnis previously served as Chief Operating Officer of Seneca from October 2015 through April 2016 and Senior Vice President of Seneca from March 2007 through September 2015.
Paula M. Ciprich (58)	Senior Vice President of the Company since April 2015; Secretary of the Company from July 2008 through June 2018; General Counsel of the Company since January 2005; Secretary of Distribution Corporation since July 2008.
Karen M. Camiolo (59)	Controller and Principal Accounting Officer of the Company since April 2004; Vice President of Distribution Corporation since April 2015; Controller of Midstream Company since April 2013; Controller of Empire since June 2007; and Controller of Distribution Corporation and Supply Corporation since April 2004.
Donna L. DeCarolis (59)	Vice President Business Development of the Company since October 2007.
Ann M. Wegrzyn (60)	Chief Information Officer of the Company since February 2017. Mrs. Wegrzyn previously served as Vice President of Distribution Corporation from December 2010 through January 2017.

(1) The executive officers serve at the pleasure of the Board of Directors. The information provided relates to the Company and its principal subsidiaries. Many of the executive officers also have served or currently serve as officers or directors of other subsidiaries of the Company.

Item 1A *Risk Factors*

As a holding company, the Company depends on its operating subsidiaries to meet its financial obligations.

The Company is a holding company with no significant assets other than the stock of its operating subsidiaries. In order to meet its financial needs, the Company relies exclusively on repayments of principal and interest on intercompany loans made by the Company to its operating subsidiaries and income from dividends and other cash flow from the subsidiaries. Such operating subsidiaries may not generate sufficient net income to pay upstream dividends or generate sufficient cash flow to make payments of principal or interest on such intercompany loans.

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

The Company relies upon short-term bank borrowings, commercial paper markets and longer-term capital markets to finance capital requirements not satisfied by cash flow from operations. The Company is dependent on these capital sources to provide capital to its subsidiaries to fund operations, acquire, maintain and develop properties, and execute growth strategies. The availability and cost of credit sources may be cyclical and these capital sources may not remain available to the Company. Turmoil in credit markets may make it difficult for the Company to obtain financing on acceptable terms or at all for working capital, capital expenditures and other investments, or to refinance maturing debt on favorable terms. These difficulties could adversely affect the Company's growth strategies, operations and financial performance. The Company's ability to borrow under its credit facilities and commercial paper agreements, and its ability to issue long-term debt under its indentures, depend on the Company's compliance with its obligations under the facilities, agreements and indentures.

In addition, the Company's short-term bank loans are in the form of floating rate debt or debt that may have rates fixed for very short periods of time, resulting in exposure to interest rate fluctuations in the absence of interest rate hedging transactions. The cost of long-term debt, the interest rates on the Company's short-term bank loans and the ability of the Company to issue commercial paper are affected by its debt credit ratings published by S&P, Moody's Investors Service, Inc. and Fitch Ratings. A downgrade in the Company's credit ratings could increase borrowing costs, negatively impact the availability of capital from banks, commercial paper purchasers and other sources, and require the Company’s subsidiaries to post letters of credit, cash or other assets as collateral with certain counterparties. Additionally, $600 million of the Company’s outstanding long-term debt would be subject to an interest rate increase if certain fundamental changes occur that involve a material subsidiary and result in a downgrade of the credit ratings assigned to the notes below investment grade. If the Company is not able to maintain investment-grade credit ratings, it may not be able to access commercial paper markets.

The Company may be adversely affected by economic conditions and their impact on our suppliers and customers.

Periods of slowed economic activity generally result in decreased energy consumption, particularly by industrial and large commercial companies. As a consequence, national or regional recessions or other downturns in economic activity could adversely affect the Company’s revenues and cash flows or restrict its future growth. Economic conditions in the Company’s utility service territories and energy marketing territories also impact its collections of accounts receivable. All of the Company’s segments are exposed to risks associated with the creditworthiness or performance of key suppliers and customers, many of which may be adversely affected by volatile conditions in the financial markets. These conditions could result in financial instability or other adverse effects at any of our suppliers or customers. For example, counterparties to the Company’s commodity hedging arrangements or commodity sales contracts might not be able to perform their obligations under these arrangements or contracts. Customers of the Company’s Utility and Energy Marketing segments may have particular trouble paying their bills during periods of declining economic activity or high commodity prices, potentially resulting in increased bad debt expense and reduced earnings. Similarly, if reductions were to occur in funding of the federal Low Income Home Energy Assistance Program, bad debt expense could increase and earnings could decrease. In addition, oil and gas exploration and production companies that are customers of the Company’s Pipeline and Storage segment may decide not to renew contracts for the same transportation capacity during periods of reduced production due to persistent low commodity prices. Any of these events could have a material adverse effect on the Company's results of operations, financial condition and cash flows.

The Company's credit ratings may not reflect all the risks of an investment in its securities.

The Company's credit ratings are an independent assessment of its ability to pay its obligations. Consequently, real or anticipated changes in the Company's credit ratings will generally affect the market value of the specific debt instruments that are rated, as well as the market value of the Company's common stock. The Company's credit ratings, however, may not reflect the potential impact on the value of its common stock of risks related to structural, market or other factors discussed in this 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, 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.

Various aspects of the Company'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 NYDEC, 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 one or more of the Company's subsidiaries.

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.

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 United States.

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.

The nature of the Company’s operations presents inherent risks of loss that could adversely affect its results of operations, financial condition and cash flows.

The Company’s operations in its various reporting segments are subject to inherent hazards and risks such as: fires; natural disasters; explosions; geological formations with abnormal pressures; blowouts during well drilling; collapses of wellbore casing or other tubulars; pipeline ruptures; spills; and other hazards and risks that may cause personal injury, death, property damage, environmental damage or business interruption losses. Additionally, the Company’s facilities, machinery, and equipment may be subject to sabotage. Any of these events could cause a loss of hydrocarbons, environmental pollution, claims for personal injury, death, property damage or business interruption, or governmental investigations, recommendations, claims, fines or penalties. As protection against operational hazards, the Company maintains insurance coverage against some, but not all, potential losses. In addition, many of the agreements that the Company executes with contractors provide for the division of responsibilities between the contractor and the Company, and the Company seeks to obtain an indemnification from the contractor for certain of these risks. The Company is not always able, however, to secure written agreements with its contractors that contain indemnification, and sometimes the Company is required to indemnify others.

Insurance or indemnification agreements, when obtained, may not adequately protect the Company against liability from all of the consequences of the hazards described above. The occurrence of an event not fully insured or indemnified against, the imposition of fines, penalties or mandated programs by governmental authorities, the failure of a contractor to meet its indemnification obligations, or the failure of an insurance company to pay valid claims could result in substantial losses to the Company. In addition, insurance may not be available, or if available may not be adequate, to cover any or all of these risks. It is also possible that insurance premiums or other costs may rise significantly in the future, so as to make such insurance prohibitively expensive.

Hazards and risks faced by the Company, and insurance and indemnification obtained or provided by the Company, may subject the Company to litigation or administrative proceedings from time to time. Such litigation or proceedings could result in substantial monetary judgments, fines or penalties against the Company or be resolved on unfavorable terms, the result of which could have a material adverse effect on the Company’s results of operations, financial condition and cash flows.

Environmental regulation significantly affects the Company’s business.

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

In addition, the Company must obtain, maintain and comply with numerous permits, leases, approvals, consents and certificates from various governmental authorities before commencing regulated activities. In connection with such activities, the Company may need to make significant capital and operating expenditures to detect, repair and/or control air emissions, to control water discharges or to perform certain corrective actions to meet the conditions of the permits issued pursuant to applicable environmental laws and regulations. Any failure to comply with applicable environmental laws and regulations and the terms and conditions of its environmental permits and authorizations could result in the assessment of significant administrative, civil and/or criminal penalties, the imposition of investigatory or remedial obligations and corrective actions, the revocation of required permits, or the issuance of injunctions limiting or prohibiting certain of the Company's operations.

Costs of compliance and liabilities could negatively affect the Company's results of operations, financial condition and cash flows. In addition, compliance with environmental laws and regulations could require unexpected capital expenditures at the Company's facilities, temporarily shut down the Company's facilities or delay or cause the cancellation of expansion projects or oil and natural gas drilling activities. Because the costs of complying with environmental regulations are significant, additional regulation could negatively affect the Company's business. Although the Company cannot predict the impact of the interpretation or enforcement of EPA standards or other federal, state and local laws or regulations, the Company's costs could increase if environmental laws and regulations change.

For further discussion of the risks associated with environmental regulation, refer to Item 7, MD&A under the heading "Environmental Matters" and subheading "Environmental Regulation."

Third parties may attempt to breach the Company's network security, which could disrupt the Company's operations and adversely affect its financial results.

The Company's information technology systems are subject to attempts by others to gain unauthorized access through the Internet, or to otherwise introduce malicious software. These attempts might be the result of industrial or other espionage, or actions by hackers seeking to harm the Company, its services or customers. These more sophisticated cyber-related attacks, as well as cybersecurity failures resulting from human error, pose a risk to the security of the Company's systems and networks and the confidentiality, availability and integrity of the Company's and its customers' data. Attempts to breach the Company's network security may result in disruption of the Company's business operations and services, delays in production, theft of sensitive and valuable data, damage to our physical systems, and reputational harm. Significant expenditures may be required to remedy breaches, including restoration of customer service and enhancement of information technology systems. The Company seeks to prevent, detect and investigate these security incidents, but in some cases the Company might be unaware of an incident or its magnitude and effects. The Company has experienced attempts to breach its network security, and although the scope of such incidents is sometimes unknown, they could prove to be material to the Company. Even though we have insurance coverage in place for cyber-related risks, if such a breach were to occur, the Company's operations, earnings and financial condition could be adversely affected to the extent not fully covered by such insurance.

Delays or changes in plans or costs with respect to Company projects, including regulatory delays or denials with respect to necessary approvals, permits or orders, could delay or prevent anticipated project completion and may result in asset write-offs and reduced earnings.

Construction of the Pipeline and Storage segment's planned pipelines and storage facilities, as well as the expansion of existing facilities, is subject to various regulatory, environmental, political, legal, economic and other development risks, including the ability to obtain necessary approvals and permits from regulatory agencies on a timely basis and on acceptable terms, or at all. For example, the Company has in the past encountered, and may in the future encounter, delays or denials by regulatory agencies in connection with certain projects, most significantly the Northern Access 2016 project. Existing or potential third party opposition, such as opposition from landowner and environmental groups, which are beyond our control, could interfere significantly with or delay the Company's receipt of such approvals or permits, which could materially affect the anticipated construction of a project. In addition, third parties could impede the Gathering segment's acquisition, expansion or renewal of rights-of-way or land rights on a timely basis and on acceptable terms. Any delay in project construction may prevent a planned project from going into service when anticipated, which could cause a delay in the receipt of revenues from those facilities. A significant construction delay in a material project, whatever the cause, or a final judgment denying a necessary permit, may result in asset write-offs and reduced earnings and an inability to complete projects as initially planned, or at all. These events could have a material adverse impact on anticipated operating results.

The Company could be adversely affected by the disallowance of purchased gas costs incurred by the Utility segment.

Tariff rate schedules in each of the Utility segment's service territories contain purchased gas adjustment clauses which permit Distribution Corporation to file with state regulators for rate adjustments to recover increases in the cost of purchased gas. Assuming those rate adjustments are granted, increases in the cost of purchased gas have no direct impact on profit margins. Distribution Corporation is required to file an accounting reconciliation with the regulators in each of the Utility segment's service territories regarding the costs of purchased gas. There is a risk of disallowance of full recovery of these costs if regulators determine that Distribution Corporation was imprudent in making its gas purchases. Any material disallowance of purchased gas costs could have a material adverse effect on cash flow and earnings.

Changes in interest rates may affect the Company's financing and its regulated businesses' rates of return.

Rising interest rates may impair the Company's ability to cost-effectively finance capital expenditures and to refinance maturing debt. In addition, the Company's authorized rate of return in its regulated businesses is based upon certain assumptions regarding interest rates. If interest rates are lower than assumed rates, the Company's authorized rate of return could be reduced. If interest rates are higher than assumed rates, the Company's ability to earn its authorized rate of return may be adversely impacted.

Fluctuations in oil and natural gas prices could adversely affect revenues, cash flows and profitability.

Operations in the Company's Exploration and Production segment are materially dependent on prices received for its oil and natural gas production. Both short-term and long-term price trends affect the economics of exploring for, developing, producing, gathering and processing oil and natural gas. Oil and natural gas prices can be volatile and can be affected by: weather conditions, natural disasters, the supply and price of foreign oil and natural gas, the level of consumer product demand, national and worldwide economic conditions, economic disruptions caused by terrorist activities, acts of war or major accidents, political conditions in foreign countries, the price and availability of alternative fuels, the proximity to, and availability of, capacity on transportation facilities, regional levels of supply and demand, energy conservation measures, and government regulations, such as regulation of greenhouse gas emissions and natural gas transportation, royalties, and price controls. The Company sells the oil and natural gas that it produces at a combination of current market prices, indexed prices or through fixed-price contracts. The Company hedges a significant portion of future sales that are based on indexed prices utilizing the physical sale counter-party or the financial markets. The prices the Company receives depend upon factors beyond the Company's control, including the factors affecting price mentioned above. The Company believes that any prolonged reduction in oil and natural gas prices could restrict its ability to continue the level of exploration and production activity the Company otherwise would pursue, which could have a material adverse effect on its revenues, cash flows and results of operations.

To the extent that the natural gas the Company produces is priced in local markets where production occurs, the price may be affected by local or regional supply and demand factors as well as other local market dynamics such as regional pipeline capacity. Currently, the prices the Company receives for its natural gas production in the local markets where production occurs are generally lower than the relevant benchmark prices, such as NYMEX, that are used for commodity trading purposes. The difference between the benchmark price and the price the Company receives is called a differential. The Company may be unable to accurately predict natural gas differentials, which may widen significantly in the future. Numerous factors may influence local commodity pricing, such as pipeline takeaway capacity and specifications, localized storage capacity, disruptions in the midstream or downstream sectors of the industry, trade restrictions and governmental regulations. Insufficient pipeline or storage capacity, or a lack of demand or surplus of supply in any given operating area may cause the differential to widen in that area compared to other natural gas producing areas. Increases in the differential could lead to production curtailments or otherwise have a material adverse effect on the Company's revenues, cash flows and results of operations.

In the Company's Pipeline and Storage segment, significant changes in the price differential between equivalent quantities of natural gas at different geographic locations could adversely impact the Company. For example, if the price of natural gas at a particular receipt point on the Company's pipeline system increases relative to the price of natural gas at other locations, then the volume of natural gas received by the Company at the relatively more expensive receipt point may decrease, or the price the Company charges to transport that natural gas may decrease. Changes in price differentials can cause shippers to seek alternative lower priced gas supplies and, consequently, alternative transportation routes. In some cases, shippers may decide not to renew transportation contracts due to changes in price differentials. While much of the impact of lower volumes under existing contracts would be offset by the straight fixed-variable rate design utilized by Supply Corporation and Empire, this rate design does not protect Supply Corporation or Empire where shippers do not contract for expiring capacity at the same quantity and rate. If contract renewals were to decrease, revenues and earnings in the Pipeline and Storage segment may decrease. Significant changes in the price differential between futures contracts for natural gas having different delivery dates could also adversely impact the Company. For example, if the prices of natural gas futures contracts for winter deliveries to locations served by the Pipeline and Storage segment decline relative to the prices of such contracts for summer deliveries (as a result, for instance, of increased production of natural gas within the Pipeline and Storage segment's geographic area or other factors), then demand for the Company's natural gas storage services driven by that price differential could decrease. Such changes in price differential could also affect the Energy Marketing segment's ability to offset its natural gas storage costs through hedging transactions. These changes could adversely affect revenues, cash flows and results of operations.

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 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.

For further discussion of the risks associated with the Dodd-Frank Act, refer to Item 7, MD&A under the heading "Market Risk Sensitive Instruments."

You should not place undue reliance on reserve information because such information represents estimates.

This Form 10-K contains estimates of the Company's proved oil and natural gas reserves and the future net cash flows from those reserves that were prepared by the Company's petroleum engineers and audited by independent petroleum engineers. Petroleum engineers consider many factors and make assumptions in estimating oil and natural gas reserves and future net cash flows. These factors include: historical production from the area compared with production from other producing areas; the assumed effect of governmental regulation; and assumptions concerning oil and natural gas prices, production and development costs, severance and excise taxes, and capital expenditures. Lower oil and natural gas prices generally cause estimates of proved reserves to be lower. Estimates of reserves and expected future cash flows prepared by different engineers, or by the same engineers at different times, may differ substantially. Ultimately, actual production, revenues and expenditures relating to the Company's reserves will vary from any estimates, and these variations may be material. Accordingly, the accuracy of the Company's reserve estimates is a function of the quality of available data and of engineering and geological interpretation and judgment.

If conditions remain constant, then the Company is reasonably certain that its reserve estimates represent economically recoverable oil and natural gas reserves and future net cash flows. If conditions change in the future, then subsequent reserve estimates may be revised accordingly. You should not assume that the present value of future net cash flows from the Company's proved reserves is the current market value of the Company's estimated oil and natural gas reserves. In accordance with SEC requirements, the Company bases the estimated discounted future net cash flows from its proved reserves on a 12-month average of historical prices for oil and natural gas (based on first day of the month prices and adjusted for hedging) and on costs as of the date of the estimate. Actual future prices and costs may differ materially from those used in the net present value estimate. Any significant price changes will have a material effect on the present value of the Company's reserves.

Petroleum engineering is a subjective process of estimating underground accumulations of natural gas and other hydrocarbons that cannot be measured in an exact manner. The process of estimating oil and natural gas reserves is complex. The process involves significant decisions and assumptions in the evaluation of available geological, geophysical, engineering and economic data for each reservoir. Future economic and operating conditions are uncertain, and changes in those conditions could cause a revision to the Company's reserve estimates in the future. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including historical production from the area compared with production from other comparable producing areas, and the assumed effects of regulations by governmental agencies. Because all reserve estimates are to some degree subjective, each of the following items may differ materially from those assumed in estimating reserves: the quantities of oil and natural gas that are ultimately recovered, the timing of the recovery of oil and natural gas reserves, the production and operating costs incurred, the amount and timing of future development and abandonment expenditures, and the price received for the production.

The amount and timing of actual future oil and natural gas production and the cost of drilling are difficult to predict and may vary significantly from reserves and production estimates, which may reduce the Company's earnings.

There are many risks in developing oil and natural gas, including numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves and in projecting future rates of production and timing of development expenditures. The future success of the Company's Exploration and Production segment depends on its ability to develop additional oil and natural gas reserves that are economically recoverable, and its failure to do so may reduce the Company's earnings. The total and timing of actual future production may vary significantly from reserves and production estimates. The Company's drilling of development wells can involve significant risks, including those related to timing, success rates, and cost overruns, and these risks can be affected by lease and rig availability, geology, and other factors. Drilling for oil and natural gas can be unprofitable, not only from non-productive wells, but from productive wells that do not produce sufficient revenues to return a profit. Also, title problems, weather conditions, governmental requirements, including completion of environmental impact analyses and compliance with other environmental laws and regulations, and shortages or delays in the delivery of equipment and services can delay drilling operations or result in their cancellation. The cost of drilling, completing, and operating wells is significant and often uncertain, and new wells may not be productive or the Company may not recover all or any portion of its investment. Production can also be delayed or made uneconomic if there is insufficient gathering, processing and transportation capacity available at an economic price to get that production to a location where it can be profitably sold. Without continued successful exploitation or acquisition activities, the Company's reserves and revenues will decline as a result of its current reserves being depleted by production. The Company cannot make assurances that it will be able to find or acquire additional reserves at acceptable costs.

Financial accounting requirements regarding exploration and production activities may affect the Company's profitability.

The Company accounts for its exploration and production activities under the full cost method of accounting. Each quarter, the Company must perform a "ceiling test" calculation, comparing the level of its unamortized investment in oil and natural gas properties to the present value of the future net revenue projected to be recovered from those properties according to methods prescribed by the SEC. In determining present value, the Company uses a 12-month historical average price for oil and natural gas (based on first day of the month prices and adjusted for hedging). If, at the end of any quarter, the amount of the unamortized investment exceeds the net present value of the projected future cash flows, such investment may be considered to be "impaired," and the full cost accounting rules require that the investment must be written down to the calculated net present value. Such an instance would require the Company to recognize an immediate expense in that quarter, and its earnings would be reduced. Depending on the magnitude of any decrease in average prices, that charge could be material. Under the Company's existing indenture covenants, an impairment could 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. For the fiscal year ended September 30, 2015, the Company recognized pre-tax impairment charges on its oil and natural gas properties of $1.1 billion. For the fiscal year ended September 30, 2016, the Company recognized a pre-tax impairment charge on its oil and natural gas properties of $948.3 million.

Increased regulation of exploration and production activities, including hydraulic fracturing, could adversely impact the Company.

Due to the burgeoning Marcellus and Utica Shale natural gas plays in the northeast United States, together with the fiscal difficulties faced by state agencies in Pennsylvania, various state legislative and regulatory initiatives regarding the exploration and production business have been proposed or adopted. These initiatives include potential new or updated statutes and regulations governing the drilling, casing, cementing, testing, abandonment and monitoring of wells, the protection of water supplies and restrictions on water use and water rights, hydraulic fracturing operations, surface owners' rights and damage compensation, the spacing of wells, use and disposal of potentially hazardous materials, and environmental and safety issues regarding natural gas pipelines. New permitting fees and/or severance taxes for oil and gas production are also possible. Additionally, legislative initiatives in the U.S. Congress and regulatory studies, proceedings or rule-making initiatives at federal, state or local agencies focused on the hydraulic fracturing process and related operations could result in additional permitting, compliance, reporting and disclosure requirements. For example, the EPA has adopted regulations that establish emission performance standards for hydraulic fracturing operations as well as natural gas gathering and transmission operations. Other EPA initiatives could expand water quality and hazardous waste regulation of hydraulic fracturing and related operations. In California, legislation regarding well stimulation, including hydraulic fracturing, has been adopted. The law mandates technical standards for well construction, hydraulic fracturing water management, groundwater monitoring, seismicity monitoring during hydraulic fracturing operations and public disclosure of hydraulic fracturing fluid constituents. Additionally, the California Division of Oil, Gas & Geothermal Resources (DOGGR) adopted regulations intended to bring California's Class II Underground Injection Control (UIC) program into compliance with the federal Safe Drinking Water Act, under which some wells may require an aquifer exemption. DOGGR began reviewing all active UIC projects, regardless of whether an exemption is required. These and any other new state, federal or local legislative or regulatory measures could lead to operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risks of litigation for the Company.

The increasing costs of certain employee and retiree benefits could adversely affect the Company's results.

The Company's earnings and cash flow may be impacted by the amount of income or expense it expends or records for employee benefit plans. This is particularly true for pension and other post-retirement benefit plans, which are dependent on actual plan asset returns and factors used to determine the value and current costs of plan benefit obligations. In addition, if medical costs rise at a rate faster than the general inflation rate, the Company might not be able to mitigate the rising costs of medical benefits. Increases to the costs of pension, other post-retirement and medical benefits could have an adverse effect on the Company's financial results.

Significant shareholders or potential shareholders may attempt to effect changes at the Company or acquire control over the Company, which could adversely affect the Company's results of operations and financial condition.

Shareholders of the Company may from time to time engage in proxy solicitations, advance shareholder proposals or otherwise attempt to effect changes or acquire control over the Company. Campaigns by shareholders to effect changes at publicly traded companies are sometimes led by investors seeking to increase short-term shareholder value through actions such as financial restructuring, increased debt, special dividends, stock repurchases or sales of assets or the entire company. Additionally, activist shareholders may submit proposals to promote an environmental, social or governance position. Responding to proxy contests and other actions by activist shareholders can be costly and time-consuming, disrupting the Company's operations and diverting the attention of the Company's Board of Directors and senior management from the pursuit of business strategies. As a result, shareholder campaigns could adversely affect the Company's results of operations and financial condition.

Item 1B *Unresolved Staff Comments*

None.

Item 2 *Properties*

General Information on Facilities

The net investment of the Company in property, plant and equipment was $5.0 billion at September 30, 2018. The Exploration and Production segment constitutes 27.5% of this investment, and is primarily located in California and in the Appalachian region of the United States. Approximately 61.4% of the Company's investment in net property, plant and equipment was in the Utility and Pipeline and Storage segments, whose operations are located primarily in western and central New York and northwestern Pennsylvania. The Gathering segment constitutes 9.9% of the Company's investment in net property, plant and equipment, and is located in northwestern Pennsylvania. The remaining net investment in property, plant and equipment consisted of the All Other category and Corporate operations (1.2%), or $0.1 billion. During the past five years, the Company has made additions to property, plant and equipment in order to expand its exploration and production operations in the Appalachian region of the United States and to expand and improve transmission facilities for transportation customers in New York and Pennsylvania. Net property, plant and equipment has decreased $175 million, or 3.4%, since September 30, 2013.

The Exploration and Production segment had a net investment in property, plant and equipment of $1.4 billion at September 30, 2018.

The Pipeline and Storage segment had a net investment of $1.6 billion in property, plant and equipment at September 30, 2018. Transmission pipeline represents 36% of this segment's total net investment and includes 2,259 miles of pipeline utilized to move large volumes of gas throughout its service area. Storage facilities represent 16% of this segment's total net investment and consist of 31 storage fields operating at a combined working gas level of 77.2 Bcf, three of which are jointly owned and operated with other interstate gas pipeline companies, and 394 miles of pipeline. Net investment in storage facilities includes $81.2 million of gas stored underground-noncurrent, representing the cost of the gas utilized to maintain pressure levels for normal operating purposes as well as gas maintained for system balancing and other purposes, including that needed for no-notice transportation service. The Pipeline and Storage segment has 32 compressor stations with 174,407 installed compressor horsepower that represent 26% of this segment's total net investment in property, plant and equipment.

The Gathering segment had a net investment of $0.5 billion in property, plant and equipment at September 30, 2018. Gathering lines and related compressors represent substantially all of this segment's total net investment, including 152 miles of lines utilized to move Appalachian production (including Marcellus and Utica Shales) to various transmission pipeline receipt points. The Gathering segment has 7 compressor stations with 69,340 installed compressor horsepower.

The Utility segment had a net investment in property, plant and equipment of $1.5 billion at September 30, 2018. The net investment in its gas distribution network (including 14,898 miles of distribution pipeline) and its service connections to customers represent approximately 48% and 33%, respectively, of the Utility segment's net investment in property, plant and equipment at September 30, 2018.

The Pipeline and Storage segments' facilities provided the capacity to meet Supply Corporation's 2018 peak day sendout for transportation service of 2,361 MMcf, which occurred on January 5, 2018. Withdrawals from storage of 628.9 MMcf provided approximately 27% of the requirements on that day.

Company maps are included in Exhibit 99.2 of this Form 10-K and are incorporated herein by reference.

Exploration and Production Activities

The Company is engaged in the exploration for and the development of natural gas and oil reserves in California and the Appalachian region of the United States. The Company has been increasing its emphasis in the Appalachian region, primarily in the Marcellus and Utica Shales. Further discussion of oil and gas producing activities is included in Item 8, Note L - Supplementary Information for Oil and Gas Producing Activities. Note L sets forth proved developed and undeveloped reserve information for Seneca. The September 30, 2018, 2017 and 2016 reserves shown in Note L are valued using 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 reserves were estimated by Seneca's geologists and engineers and were audited by independent petroleum engineers from Netherland, Sewell & Associates, Inc. Note L discusses the qualifications of the Company's reservoir engineers, internal controls over the reserve estimation process and audit of the reserve estimates and changes in proved developed and undeveloped oil and natural gas reserves year over year.

Seneca's proved developed and undeveloped natural gas reserves increased from 1,973 Bcf at September 30, 2017 to 2,357 Bcf at September 30, 2018. This increase is attributed to extensions and discoveries of 522 Bcf and upward revisions of previous estimates of 93 Bcf, partially offset by production of 163 Bcf and sales of minerals in place of 68 Bcf. Of the total upward gas revisions of 93 Bcf, 96 Bcf were a result of upward revisions due to performance improvements, and 2 Bcf were a result of higher gas prices, partially offset by 5 Bcf of PUD locations that were removed. The sales of minerals in place were primarily the result of Marcellus reserves that were sold in the Western Development Area as part of the joint development agreement (JDA) with IOG CRV - Marcellus, LLC (IOG)(57 Bcf), coupled with the sale of Seneca's Sespe Field area in May 2018 (11 Bcf).

Seneca's proved developed and undeveloped oil reserves decreased from 30,207 Mbbl at September 30, 2017 to 27,663 Mbbl at September 30, 2018. The decrease is attributed to production of 2,535 Mbbl, primarily occurring in the West Coast region, and sales of minerals in place of 4,787 Mbbl, partially offset by extensions and discoveries of 2,301 Mbbl and upward revisions of previous estimates of 2,477 Mbbl. The sales of minerals in place were primarily the result of the aforementioned sale of Seneca's Sespe Field area in May 2018. Upward revisions of 2,477 Mbbl were a result of both higher oil prices of 1,975 Mbbl and upward revisions associated with performance improvements of 502 Mbbl.

On a Bcfe basis, Seneca's proved developed and undeveloped reserves increased from 2,154 Bcfe at September 30, 2017 to 2,523 Bcfe at September 30, 2018. This increase is attributed to extensions and discoveries of 536 Bcfe and upward revisions of previous estimates of 108 Bcfe, partially offset by production of 178 Bcfe and sales of minerals in place of 97 Bcfe.

Seneca's proved developed and undeveloped natural gas reserves increased from 1,675 Bcf at September 30, 2016 to 1,973 Bcf at September 30, 2017. This increase is attributed to extensions and discoveries of 386 Bcf and upward revisions of previous estimates of 91 Bcf, partially offset by production of 157 Bcf and sales of minerals in place of 22 Bcf. Of the total upward gas revisions of 91 Bcf, 125 Bcf were a result of higher gas prices for Marcellus Shale, Utica Shale and other reservoirs, and 20 Bcf were a result of upward revisions due to performance improvements and lease operating expense reductions, partially offset by 54 Bcf of PUD locations that were removed. The sales of minerals in place were the result of Marcellus and Utica reserves that were sold in the Western Development Area (primarily in Forest, Elk, McKean and Cameron counties in Pennsylvania) in September 2017.

Seneca's proved developed and undeveloped oil reserves increased from 29,009 Mbbl at September 30, 2016 to 30,207 Mbbl at September 30, 2017. The increase is attributed to extensions and discoveries of 674 Mbbl and upward revisions of previous estimates of 3,293 Mbbl, partially offset by production of 2,740 Mbbl, primarily occurring in the West Coast region, and sales of minerals in place of 29 Mbbl. Upward revisions of 3,293 Mbbl were a result of both higher oil prices of 1,623 Mbbl and upward revisions associated with performance improvements of 1,670 Mbbl. The sales of minerals in place were the result of aforementioned sales of reserves in the Western Development Area.

On a Bcfe basis, Seneca's proved developed and undeveloped reserves increased from 1,849 Bcfe at September 30, 2016 to 2,154 Bcfe at September 30, 2017. This increase is attributed to extensions and discoveries of 391 Bcfe and upward revisions of previous estimates of 110 Bcfe, partially offset by production of 174 Bcfe and sales of minerals in place of 22 Bcfe.

At September 30, 2018, the Company's Exploration and Production segment had delivery commitments of 2,036 Bcfe (mostly natural gas as commitments for crude oil were insignificant). The Company expects to meet those commitments through proved reserves, including the future development of reserves that are currently classified as proved undeveloped reserves and future extensions and discoveries.

The following is a summary of certain oil and gas information taken from Seneca's records. All monetary amounts are expressed in U.S. dollars.

Production

	For The Year Ended September 30		
	2018	2017	2016
United States			
Appalachian Region			
Average Sales Price per Mcf of Gas	$ 2.36 (1)	$ 2.52 (1)	$ 1.94 (1)
Average Sales Price per Barrel of Oil	$ 57.76	$ 48.27	$ 52.15
Average Sales Price per Mcf of Gas (after hedging)	$ 2.49	$ 2.93	$ 3.01
Average Sales Price per Barrel of Oil (after hedging)	$ 57.76	$ 48.27	$ 52.15
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.69 (1)	$ 0.71 (1)	$ 0.73 (1)
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	440 (1)	422 (1)	385 (1)
West Coast Region			
Average Sales Price per Mcf of Gas	$ 4.86	$ 4.00	$ 3.25
Average Sales Price per Barrel of Oil	$ 66.39	$ 46.14	$ 35.26
Average Sales Price per Mcf of Gas (after hedging)	$ 4.86	$ 4.00	$ 3.25
Average Sales Price per Barrel of Oil (after hedging)	$ 58.66	$ 53.85	$ 57.97
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 2.98	$ 2.91	$ 2.47
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	48	53	56
Total Company			
Average Sales Price per Mcf of Gas	$ 2.40	$ 2.55	$ 1.97
Average Sales Price per Barrel of Oil	$ 66.38	$ 46.18	$ 35.42
Average Sales Price per Mcf of Gas (after hedging)	$ 2.52	$ 2.95	$ 3.02
Average Sales Price per Barrel of Oil (after hedging)	$ 58.66	$ 53.87	$ 57.91
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.91	$ 0.96	$ 0.96
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	488	475	441

(1) The Marcellus Shale fields (which exceed 15% of total reserves at September 30, 2018, 2017 and 2016) contributed 412 MMcfe, 399 MMcfe and 372 MMcfe of daily production in 2018, 2017 and 2016, respectively. The average lifting costs (per Mcfe) were $0.69 in 2018, $0.71 in 2017 and $0.72 in 2016. The Utica Shale fields (which exceed 15% of total reserves at September 30, 2018) contributed 26 MMcfe of daily production in 2018. The average lifting costs (per Mcfe) were $0.64 in 2018. The average sales price for the Marcellus and Utica Shale fields (per Mcfe) were $2.36 ($2.49 after hedging) in 2018, $2.52 ($2.93 after hedging) in 2017 and $1.94 ($3.01 after hedging) in 2016.

Productive Wells

	Appalachian Region		West Coast Region		Total Company	
At September 30, 2018	Gas	Oil	Gas	Oil	Gas	Oil
Productive Wells — Gross	472	—	—	1,917	472	1,917
Productive Wells — Net	367	—	—	1,884	367	1,884

Developed and Undeveloped Acreage

At September 30, 2018	Appalachian Region		West Coast Region	Total Company
Developed Acreage				
— Gross	527,544		17,101	544,645
— Net	518,518		15,769	534,287
Undeveloped Acreage				
— Gross	355,110		120	355,230
— Net	341,074		30	341,104
Total Developed and Undeveloped Acreage				
— Gross	882,654		17,221	899,875
— Net	859,592	(1)	15,799	875,391

(1) Of the 859,592 Total Developed and Undeveloped Net Acreage in the Appalachian region as of September 30, 2018, there are a total of 800,683 net acres in Pennsylvania. Of the 800,683 total net acres in Pennsylvania, shale development in the Marcellus, Utica or Geneseo shales has occurred on approximately 57,846 net acres, or 7.2% of Seneca's total net acres in Pennsylvania. The high amount of developed acreage in the table largely reflects development in the Upper Devonian geological formation and masks the potential for development beneath this formation, which includes the Marcellus, Utica and Geneseo shales.

As of September 30, 2018, the aggregate amount of gross undeveloped acreage expiring in the next three years and thereafter are as follows: 3,704 acres in 2019 (3,704 net acres), 446 acres in 2020 (356 net acres), 2 acres in 2021 (2 net acres) and 37,830 acres thereafter (36,735 net acres). The remaining 313,248 gross acres (300,307 net acres) represent non-expiring oil and gas rights owned by the Company. Of the acreage that is currently scheduled to expire in 2019, 2020 and 2021, Seneca has no associated proved undeveloped gas reserves. As a part of its management approved development plan, Seneca generally commences development of these reserves prior to the expiration of the leases and/or proactively extends/renews these leases.

Drilling Activity

	Productive			Dry		
For the Year Ended September 30	2018	2017	2016	2018	2017	2016
United States						
Appalachian Region						
Net Wells Completed						
— Exploratory	4.00	9.00	1.00	—	—	—
— Development	41.40	25.40	31.80	9.00	3.00	1.00
West Coast Region						
Net Wells Completed						
— Exploratory	—	—	—	—	—	—
— Development	15.00	14.00	25.00	—	—	—
Total Company						
Net Wells Completed						
— Exploratory	4.00	9.00	1.00	—	—	—
— Development	56.40	39.40	56.80	9.00	3.00	1.00

Present Activities

At September 30, 2018	Appalachian Region	West Coast Region	Total Company
Wells in Process of Drilling(1)			
— Gross	63.00	—	63.00
— Net	48.50	—	48.50

(1) Includes wells awaiting completion.

Item 3 *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 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 II, Item 7, MD&A and Item 8 at Note I — Commitments and Contingencies.

For a discussion of certain rate matters involving the NYPSC, refer to Part II, Item 7, MD&A of this report under the heading "Other Matters - Rate and Regulatory Matters."

Item 4 *Mine Safety Disclosures*

Not Applicable.

PART II

Item 5 *Market for the Registrant’s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

At September 30, 2018, there were 10,751 registered shareholders of Company common stock. The common stock is listed and traded on the New York Stock Exchange under the trading symbol "NFG". Information regarding the market for the Company’s common equity and related stockholder matters appears under Item 12 at Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters and Item 8 at Note E — Capitalization and Short-Term Borrowings.

On July 2, 2018, the Company issued a total of 6,616 unregistered shares of Company common stock to the eight non-employee directors of the Company then serving on the Board of Directors of the Company, 827 shares to each such director. On July 16, 2018, the Company issued 707 unregistered shares of Company stock to Steven C. Finch, who joined the Board on July 12, 2018 as a non-employee director. All of these unregistered shares were issued under the Company’s 2009 Non-Employee Director Equity Compensation Plan as partial consideration for such directors’ services during the quarter ended September 30, 2018. These transactions were exempt from registration under Section 4(a)(2) of the Securities Act of 1933, as transactions not involving a public offering.

Issuer Purchases of Equity Securities

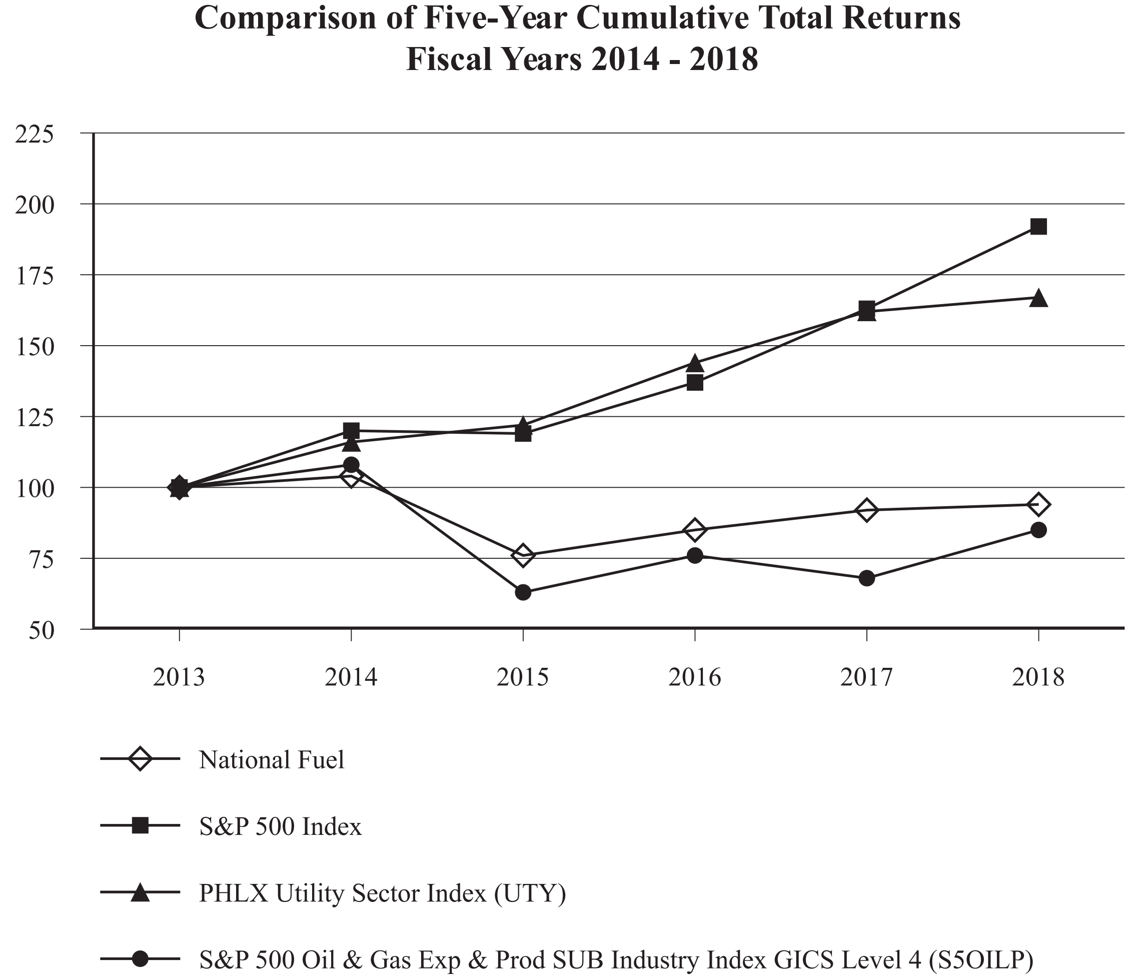
Period	Total Number of Shares Purchased(a)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Share Repurchase Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under Share Repurchase Plans or Programs(b)
July 1-31, 2018	9,542	$ 54.66	—	6,971,019
Aug. 1-31, 2018	10,972	$ 55.51	—	6,971,019
Sept. 1-30, 2018	10,311	$ 56.63	—	6,971,019
Total	30,825	$ 55.62	—	6,971,019

(a) Represents (i) shares of common stock of the Company purchased on the open market with Company “matching contributions” for the accounts of participants in the Company’s 401(k) plans, and (ii) shares of common stock of the Company tendered to the Company by holders of stock-based compensation awards for the payment of applicable withholding taxes. During the quarter ended September 30, 2018, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program. Of the 30,825 shares purchased other than through a publicly announced share repurchase program, 28,089 were purchased for the Company’s 401(k) plans and 2,736 were purchased as a result of shares tendered to the Company by holders of stock-based compensation awards.

(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.

Performance Graph

The following graph compares the Company's common stock performance with the performance of the S&P 500 Index, the PHLX Utility Sector Index and the S&P 500 Oil & Gas Exploration & Production SUB Industry Index GICS Level 4 for the period September 30, 2013 through September 30, 2018. The graph assumes that the value of the investment in the Company's common stock and in each index was $100 on September 30, 2013 and that all dividends were reinvested.



	2013	2014	2015	2016	2017	2018
National Fuel	$100	$104	$76	$85	$92	$94
S&P 500 Index	$100	$120	$119	$137	$163	$192
PHLX Utility Sector Index (UTY)	$100	$116	$122	$144	$162	$167
S&P 500 Oil & Gas Exp & Prod SUB Industry Index GICS Level 4 (S5OILP)	$100	$108	$63	$76	$68	$85

Source: Bloomberg

The performance graph above is furnished and not filed for purposes of Section 18 of the Securities Exchange Act of 1934 and will not be incorporated by reference into any registration statement filed under the Securities Act of 1933 unless specifically identified therein as being incorporated therein by reference. The performance graph is not soliciting material subject to Regulation 14A.

Item 6 ***Selected Financial Data***

	Year Ended September 30				
	2018	2017	2016	2015	2014
	(Thousands, except per share amounts and number of registered shareholders)				
Summary of Operations					
Operating Revenues:					
Utility and Energy Marketing Revenues	$ 812,474	$ 755,485	$ 624,602	$ 860,618	$ 1,103,149
Exploration and Production and Other Revenues	569,808	617,666	611,766	696,709	808,595
Pipeline and Storage and Gathering Revenues	210,386	206,730	216,048	203,586	201,337
	1,592,668	1,579,881	1,452,416	1,760,913	2,113,081
Operating Expenses:					
Purchased Gas	337,822	275,254	147,982	349,984	605,838
Operation and Maintenance:					
Utility and Energy Marketing	200,780	199,293	192,512	203,249	196,534
Exploration and Production and Other	141,381	145,099	160,201	184,024	188,622
Pipeline and Storage and Gathering	100,245	98,200	88,801	82,730	77,922
Property, Franchise and Other Taxes	84,393	84,995	81,714	89,564	90,711
Depreciation, Depletion and Amortization	240,961	224,195	249,417	336,158	383,781
Impairment of Oil and Gas Producing Properties	—	—	948,307	1,126,257	—
	1,105,582	1,027,036	1,868,934	2,371,966	1,543,408
Operating Income (Loss)	487,086	552,845	(416,518)	(611,053)	569,673
Other Income (Expense):					
Other Income	4,697	7,043	9,820	8,039	9,461
Interest Income	6,766	4,113	4,235	3,922	4,170
Interest Expense on Long-Term Debt	(110,946)	(116,471)	(117,347)	(95,916)	(90,194)
Other Interest Expense	(3,576)	(3,366)	(3,697)	(3,555)	(4,083)
Income (Loss) Before Income Taxes	384,027	444,164	(523,507)	(698,563)	489,027
Income Tax Expense (Benefit)	(7,494)	160,682	(232,549)	(319,136)	189,614
Net Income (Loss) Available for Common Stock	$ 391,521	$ 283,482	$ (290,958)	$ (379,427)	$ 299,413
Per Common Share Data					
Basic Earnings (Loss) per Common Share	$ 4.56	$ 3.32	$ (3.43)	$ (4.50)	$ 3.57
Diluted Earnings (Loss) per Common Share	$ 4.53	$ 3.30	$ (3.43)	$ (4.50)	$ 3.52
Dividends Declared	$ 1.68	$ 1.64	$ 1.60	$ 1.56	$ 1.52
Dividends Paid	$ 1.67	$ 1.63	$ 1.59	$ 1.55	$ 1.51
Dividend Rate at Year-End	$ 1.70	$ 1.66	$ 1.62	$ 1.58	$ 1.54
At September 30:					
Number of Registered Shareholders	10,751	11,211	11,751	12,147	12,654

	Year Ended September 30				
	2018	2017	2016	2015	2014
	(Thousands, except per share amounts and number of registered shareholders)				
Net Property, Plant and Equipment					
Exploration and Production	$1,370,340	$1,196,521	$1,083,804	$2,126,265	$2,897,744
Pipeline and Storage	1,583,699	1,524,197	1,463,541	1,387,516	1,187,924
Gathering	493,694	455,701	439,660	400,409	292,793
Utility	1,469,645	1,435,414	1,403,286	1,351,504	1,297,179
Energy Marketing	1,267	1,503	1,745	1,989	2,070
All Other	56,295	57,960	59,054	60,404	61,236
Corporate	2,203	2,778	3,392	3,808	4,145
Total Net Plant	$4,977,143	$4,674,074	$4,454,482	$5,331,895	$5,743,091
Total Assets	$6,036,486	$6,103,320	$5,636,387	$6,564,939	$6,687,717
Capitalization					
Comprehensive Shareholders' Equity	$1,937,330	$1,703,735	$1,527,004	$2,025,440	$2,410,683
Long-Term Debt, Net of Current Portion and Unamortized Discount and Debt Issuance Costs	2,131,365	2,083,681	2,086,252	2,084,009	1,637,443
Total Capitalization	$4,068,695	$3,787,416	$3,613,256	$4,109,449	$4,048,126

Item 7 *Management's Discussion and Analysis of Financial Condition and Results of Operations*

OVERVIEW

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. Refer to Item 1, Business, for a more detailed description of each of the segments.

Corporate Responsibility

The Board of Directors and management recognize that the long-term interests of stockholders are served by considering the interests of customers, employees and the communities in which the Company operates. In addition, the Company strives to comply with all applicable legal and regulatory requirements and to adhere to high standards of ethics and integrity. The Board retains oversight of safety, environmental, social, cybersecurity and corporate governance risks, among other areas central to corporate responsibility. An important aspect of that oversight is the Enterprise Risk Management process. Management reports quarterly to the Board on significant risk categories. In addition, Management provides a detailed presentation on a topic related to one or more risk categories at each Board meeting.

The Board directs management to integrate corporate responsibility concerns into decision-making throughout the organization. The Company takes very seriously its role as a corporate citizen and remains committed to the welfare of the areas in which it operates, as it has for over 100 years. Toward that end, the Company has affirmed six “Guiding Principles” (Safety, Environmental Stewardship, Community, Innovation, Satisfaction and Transparency). These principles reflect and promote a culture that is committed to the tenets of corporate responsibility.

The Company recognizes the ongoing debate regarding climate change, including questions surrounding potential physical, technological, regulatory and social risks, as well as corresponding opportunities. The Board and management consider these risks and opportunities in their strategic and capital spending decision process. Further, since the Company operates an integrated business with assets being utilized for, and benefiting from, the production, transportation and consumption of natural gas, the Board and management consider the impact of the climate change debate on future natural gas usage.

The U.S. Energy Information Administration (EIA) provides relevant data and projections in this regard. The EIA’s 2017 International Energy Outlook projects that worldwide natural gas consumption will increase 43% from 2015 through 2040. Natural gas is a versatile fuel and this increase is projected to transcend all sectors, with the largest increases seen in the industrial and electric generation sectors. The EIA’s 2018 Annual Energy Outlook further projects that, through 2050, U.S. natural gas consumption will increase more than any other fuel source and will account for the largest share of total energy production. The EIA anticipates that shale gas and tight oil production could potentially account for 75% of U.S. natural gas production by 2050 as companies leverage technological advances in horizontal drilling and hydraulic fracturing to develop previously uneconomic or unreachable reserves. The EIA anticipates that “continued development of the Marcellus and Utica plays in the East is the main driver of growth in total U.S. shale gas production[.]” Management reviews these, and other, projections with the Board which considers such projections in setting and reviewing the Company’s capital budget.

The Company believes that its conservative approach to capital investments combined with its history, experience, assets, and fully-integrated approach put it in a position for success in the current and evolving regulatory landscape. As recognized by the EIA, natural gas is a clean fossil fuel when compared to other fossil fuels such as oil or coal with respect to greenhouse gas emissions. In its 2018 New York State Greenhouse Gas Inventory Report, the New York State Energy Research and Development Authority noted that from 1990 to 2015, “emissions from electricity generated in-State dropped 54 percent during this . . . period, acting as a major driver of New York State’s decreasing GHG emissions. This drop is due in part to the significant decrease in the burning of coal and petroleum products in the electricity generation sector. Emissions from residential, commercial, and industrial buildings also decreased, showing a reduction of approximately 16 percent from 1990 to 2015. This reduction in emissions was driven by a decrease in the use of coal and petroleum, paired with an increase in the use of natural gas.” The Company believes that ongoing development of natural gas will help drive a continued reduction in overall greenhouse gas emissions.

The Company recognizes that there exists an evolving landscape of international accords and federal, state and local laws and regulations regarding greenhouse gas emissions or climate change initiatives. Changing market conditions and new regulatory requirements, as well as unanticipated or inconsistent application of existing laws and regulations by administrative agencies, make it difficult to predict a long-term business impact across twenty or more years. The Company adjusts its approach to capital investment in response to regulatory change. For instance, given what appears to be the imposition of unattainable regulatory standards by the current executive administration of one of the states in which the Company does business, the Company is shifting its investment focus away from that state with respect to new pipeline expansion projects.

While natural gas has lower greenhouse gas emissions than other fossil fuels, the natural gas value chain does result in greenhouse gas emissions. The Company recognizes the important role of ongoing system modernization and efficiency in reducing greenhouse gas emissions. In its Utility, the Company directs capital spending to replacement and to other investments (such as the purchase of vehicles and equipment necessary for that activity) that support its statutory obligation to provide safe and reliable service. In its Pipeline and Storage businesses, a significant portion of the capital budget is spent on modernization, including leveraging expansion projects to also upgrade existing infrastructure. In its Exploration and Production segment, the Company has implemented initiatives throughout the drilling process that are aimed at minimizing greenhouse gas emissions and improving air quality, including green completion techniques and deploying leak detection technologies. Likewise, the Exploration and Production segment recognizes the importance of efficient and innovative water sourcing, handling and recycling. To assist in water management, the Company established a water logistics company, Highland Field Services, to improve its water resourcing and recycling capabilities.

The Company's replacement of older natural gas infrastructure leads to fewer leaks and directly results in lower greenhouse gas emissions. For instance, as a result of system modernization, the Utility segment, from 2012 to 2017, has seen a 17.4% reduction in greenhouse gas emissions, primarily methane, reported to the EPA under Subpart W of 40 CFR Part 98.

The Company also works with various regulatory commissions to develop ratemaking initiatives to increase end use efficiency while reducing downside risk from demand fluctuation. In addition, in 2018 subsidiaries of the Company's Utility, Pipeline and Storage, Midstream and Exploration and Production segments all joined the EPA's Natural Gas STAR Methane Challenge Program and made commitments to adopt practices aimed at reducing methane emissions.

Fiscal 2018 Highlights

This Item 7, MD&A, provides information concerning:

1. The critical accounting estimates of the Company;
2. Changes in revenues and earnings of the Company under the heading, "Results of Operations;"
3. Operating, investing and financing cash flows under the heading "Capital Resources and Liquidity;"
4. Off-Balance Sheet Arrangements;
5. Contractual Obligations; and
6. Other Matters, including: (a) 2018 and projected 2019 funding for the Company's pension and other post-retirement benefits; (b) disclosures and tables concerning market risk sensitive instruments; (c) rate and regulatory matters in the Company's New York, Pennsylvania and FERC-regulated jurisdictions; (d) environmental matters; and (e) new authoritative accounting and financial reporting guidance.

The information in MD&A should be read in conjunction with the Company's financial statements in Item 8 of this report.

For the year ended September 30, 2018 compared to the year ended September 30, 2017, the Company experienced an increase in earnings of $108.0 million. As a result of the 2017 Tax Reform Act, the effective tax rate for the year ended September 30, 2018 of negative 2.0% reflects a lower statutory rate of 24.5% as well as the impact of a remeasurement of the Company's accumulated deferred income tax liability based upon the new tax rates, recorded as a $103.5 million reduction to income tax expense. The Company's non-regulated operations are benefiting from the 2017 Tax Reform Act. With regard to the Company's regulated operations, Distribution Corporation's New York and Pennsylvania jurisdictions have received orders requiring rate reductions associated with the 2017 Tax Reform Act. In the Pipeline and Storage segment, Supply Corporation will be making a filing with FERC by December 6, 2018 to address the impact of tax reform. For Empire, the impact of tax reform is being addressed in its current section 4 rate case. For further discussion of the impact of the 2017 Tax Reform Act to the Company, refer to Rate and Regulatory Matters below and to Item 8 at Note D — 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 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. On August 6, 2018, the FERC issued an Order finding that the NYDEC exceeded the statutory time frame to take action under the Clean Water Act and, therefore, waived its opportunity to approve or deny the Water Quality Certification. Rehearing requests have been filed at FERC. The Company remains committed to the project. In light of these pending legal actions and the need to complete necessary project development activities in advance of construction, the target in-service date for the project is expected to be no earlier than the first half of fiscal 2022. Approximately $76.2 million in costs have been incurred on this project through September 30, 2018, 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. For further discussion of the Northern Access project, refer to Item 8 at Note I — Commitments and Contingencies.

While legal proceedings continue on the Northern Access project, the Company continues to pursue development projects to expand its Pipeline and Storage segment. One project on Empire's system, referred to as the Empire North Project, 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. The Empire North Project has a projected in-service date in the second half of fiscal 2020 and an estimated cost of approximately $145 million. Another project on Supply Corporation's system, referred to as the FM 100 Project, is currently in the pre-filing process at FERC and will upgrade 1950's era pipeline in northwestern Pennsylvania and create approximately 330,000 Dth per day of additional capacity on Supply Corporation's system in Pennsylvania from a receipt point with NFG Midstream Clermont, LLC in McKean County, Pennsylvania to the Transcontinental Gas Pipe Line Company, LLC system at Leidy, Pennsylvania. The FM 100 Project has a target in-service date in late calendar 2021 and a preliminary cost estimate of approximately $280 million. These and other projects are discussed in more detail in the Capital Resources and Liquidity section that follows.

The Company also continues to grow its Exploration and Production segment. Seneca's proved reserves grew 17% from the prior year to a total of 2,523 Bcfe at September 30, 2018. During the fiscal year, Seneca transitioned from operating two drilling rigs in Pennsylvania to three rigs. This increased drilling activity is expected to result in meaningful production and reserve growth in fiscal 2019. More detail regarding the Exploration and Production segment's capital expenditures in fiscal 2018 and beyond are discussed in the Capital Resources and Liquidity section that follows.

From a financing perspective, in August 2018, the Company issued $300.0 million of 4.75% notes due in September 2028. The proceeds of the debt issuance were used for general corporate purposes, including the September 2018 redemption of $250.0 million of the Company's 8.75% notes that were scheduled to mature in May 2019. The Company expects to use cash on hand and cash from operations to meet its capital expenditure needs for fiscal 2019 and may issue short-term and/or long-term debt during fiscal 2019 as needed.

CRITICAL ACCOUNTING ESTIMATES

The Company has prepared its consolidated financial statements in conformity with GAAP. The preparation of these financial statements 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. In the event estimates or assumptions prove to be different from actual results, adjustments are made in subsequent periods to reflect more current information. The following is a summary of the Company's most critical accounting estimates, which are defined as those estimates whereby judgments or uncertainties could affect the application of accounting policies and materially different amounts could be reported under different conditions or using different assumptions. For a complete discussion of the Company's significant accounting policies, refer to Item 8 at Note A — Summary of Significant Accounting Policies.

Oil and Gas Exploration and Development Costs. 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 accounting 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.

Proved reserves are estimated quantities of reserves that, based on geologic and engineering data, appear with reasonable certainty to be producible under existing economic and operating conditions. Such estimates of proved reserves are inherently imprecise and may be subject to substantial revisions as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. The estimates involved in determining proved reserves are critical accounting estimates because they serve as the basis over which capitalized costs are depleted under the full cost method of accounting (on a units-of-production basis). Unproved properties are excluded from the depletion calculation until proved reserves are found or it is determined that the unproved properties are impaired. 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.

In addition to depletion under the units-of-production method, proved reserves are a major component in the SEC full cost ceiling test. The full cost ceiling test is an impairment test prescribed by SEC Regulation S-X Rule 4-10. 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 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 (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 estimates of future production and future expenditures are based on internal budgets that reflect planned production from current wells and expenditures necessary to sustain such future production. The amount of the ceiling can fluctuate significantly from period to period because of additions to or subtractions from proved reserves and significant fluctuations in oil and gas prices. The ceiling is then compared to the capitalized cost of oil and gas properties less accumulated depletion and related deferred income taxes. If the capitalized costs of oil and gas properties less accumulated depletion and related deferred taxes exceeds the ceiling at the end of any fiscal quarter, a non-cash impairment charge must be recorded to write down the book value of the reserves to their present value. This non-cash impairment cannot be reversed at a later date if the ceiling increases. It should also be noted that a non-cash impairment to write down the book value of the reserves to their present value in any given period causes a reduction in future depletion expense. At September 30, 2018, the ceiling exceeded the book value of the oil and gas properties by approximately \$569.1 million. The 12-month average of the first day of the month price for crude oil for each month during 2018, based on posted Midway Sunset prices, was \$64.09 per Bbl. The 12-month average of the first day of the month price for natural gas for each month during 2018, based on the quoted Henry Hub spot price for natural gas, was \$2.91 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 2018. 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 September 30, 2018 (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 September 30, 2018, if crude oil prices were \$5 per Bbl lower than the average prices used at September 30, 2018, 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 September 30, 2018 (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	\$ 391.1	\$ 536.1	\$ 358.1

It is difficult to predict what factors could lead to future impairments under the SEC's full cost ceiling test. As discussed above, 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.

In accordance with the current authoritative guidance for asset retirement obligations, the Company records an asset retirement obligation for plugging and abandonment costs associated with the Exploration and Production segment's crude oil and natural gas wells and capitalizes such costs in property, plant and equipment (i.e. the full cost pool). Under the current authoritative guidance for asset retirement obligations, since plugging and abandonment costs are already included in the full cost pool, the units-of-production depletion calculation excludes from the depletion base any estimate of future plugging and abandonment costs that are already recorded in the full cost pool.

As discussed above, the full cost method of accounting provides a ceiling to the amount of costs that can be capitalized in the full cost pool. In accordance with current authoritative guidance, the future cash outflows associated with plugging and abandoning wells are excluded from the computation of the present value of estimated future net revenues for purposes of the full cost ceiling calculation.

Regulation. The Company is subject to regulation by certain state and federal authorities. The Company, in its Utility and Pipeline and Storage segments, has accounting policies which conform to the FASB authoritative guidance regarding accounting for certain types of regulations, and which are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. The application of these accounting principles for certain types of rate-regulated activities provide that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's assessment of the probability of recovery or pass through of regulatory assets and liabilities requires judgment and interpretation of laws and regulatory commission orders. If, for any reason, the Company ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the balance sheet and included in the income statement for the period in which the discontinuance of regulatory accounting treatment occurs. Such amounts would be classified as an extraordinary item. For further discussion of the Company's regulatory assets and liabilities, refer to Item 8 at Note C — Regulatory Matters.

Accounting for Derivative Financial Instruments. The Company uses a variety of derivative financial instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and crude oil in its Exploration and Production and Energy Marketing segments. These instruments are categorized as price swap agreements and futures contracts. In accordance with the authoritative guidance for derivative instruments and hedging activities, the Company primarily accounts for these instruments as effective cash flow hedges or fair value hedges. 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. Gains or losses associated with the derivative financial instruments that are accounted for as cash flow or fair value hedges are matched with gains or losses resulting from the underlying physical transaction that is being hedged. To the extent that such derivative financial instruments would ever be deemed to be ineffective based on effectiveness testing, mark-to-market gains or losses from such derivative financial instruments would be recognized in the income statement without regard to an underlying physical transaction. Refer to the "Market Risk Sensitive Instruments" section below for further discussion of the Company's derivative financial instruments and refer to Item 8 at Note F—Fair Value Measurements for discussion of the determination of fair value for derivative financial instruments.

Pension and Other Post-Retirement Benefits. The amounts reported in the Company's financial statements related to its pension and other post-retirement benefits are determined on an actuarial basis, which uses many assumptions in the calculation of such amounts. These assumptions include the discount rate, the expected return on plan assets, the rate of compensation increase and, for other post-retirement benefits, the expected annual rate of increase in per capita cost of covered medical and prescription benefits. The Company determines the service and interest cost components of net periodic benefit cost using the spot rate approach. Under this approach, the Company uses individual spot rates along the yield curve that correspond to the timing of each benefit payment in order to determine the discount rate. The individual spot rates along the yield curve are determined by an above mean methodology in that the coupon interest rates that are in the lower 50th percentile are excluded based on the assumption that the Company would not utilize more expensive (i.e. lower yield) instruments to settle its liabilities. The expected return on plan assets assumption used by the Company reflects the anticipated long-term rate of return on the plan's current and future assets. The Company utilizes historical investment data, projected capital market conditions, and the plan's target asset class and investment manager allocations to set the assumption regarding the expected return on plan assets. Changes in actuarial assumptions and actuarial experience, including deviations between actual versus expected return on plan assets, could have a material impact on the amount of pension and post-retirement benefit costs and funding requirements experienced by the Company. However, the Company expects to recover a substantial portion of its net periodic pension and other post-retirement benefit costs attributable to employees in its Utility and Pipeline and Storage segments in accordance with the applicable regulatory commission authorization, subject to applicable accounting requirements for rate-regulated activities, as discussed above under "Regulation."

Changes in actuarial assumptions and actuarial experience could also have an impact on the benefit obligation and the funded status related to the Company's pension and other post-retirement benefits and could impact the Company's equity. For example, the discount rate used to determine benefit obligations of the Company's other post-retirement benefits changed from 3.81% in 2017 to 4.31% in 2018. The change in the discount rate from 2017 to 2018 decreased the accumulated post-retirement benefit obligation by $25.8 million. The discount rate used to determine benefit obligations of the Retirement Plan changed from 3.77% in 2017 to 4.30% in 2018. The change in the discount rate from 2017 to 2018 decreased the Retirement Plan projected benefit obligation by $58.1 million. Other examples include actual versus expected return on plan assets, which has an impact on the funded status of the plans, and actual versus expected benefit payments, which has an impact on the pension plan projected benefit obligation and the accumulated post-retirement benefit obligation. For 2018, the actual return on plan assets was lower than the expected return, which resulted in a decrease to the funded status of the Retirement Plan ($19.1 million) as well as a decrease to the funded status of the VEBA trusts and 401(h) accounts ($10.8 million). The actual versus expected benefit payments for 2018 caused a decrease of $2.1 million to the accumulated post-retirement benefit obligation. In addition, changes in per-capita claim costs, premiums, retiree contributions and retiree drug subsidy assumptions in order to better reflect anticipated experience based on actual experience resulted in an increase to the accumulated post-retirement benefit obligation of $3.8 million. In calculating the projected benefit obligation for the Retirement Plan and the accumulated post-retirement obligation, the actuary takes into account the average remaining service life of active participants. The average remaining service life of active participants is 7 years for the Retirement Plan and 5 years for those eligible for other post-retirement benefits. For further discussion of the Company's pension and other post-retirement benefits, refer to Other Matters in this Item 7, which includes a discussion of funding for the current year, and to Item 8 at Note H — Retirement Plan and Other Post Retirement Benefits.

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 a 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.

The Company has determined a reasonable estimate under Staff Accounting Bulletin (SAB) 118 for the measurement of the changes in deferred income taxes in the September 30, 2018 financial statements. The final determination of the impact of the income tax effects of these items will require 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 possible technical corrections, which, if issued, the Company expects to finalize within SAB 118's measurement period (quarter ended December 31, 2018). Any subsequent guidance will be accounted for in the period issued. For further discussion of the impact of the 2017 Tax Reform Act to the Company, refer to Item 8 at Note D — Income Taxes.

RESULTS OF OPERATIONS

EARNINGS

2018 Compared with 2017

The Company's earnings were $391.5 million in 2018 compared with earnings of $283.5 million in 2017. The increase in earnings of $108.0 million was primarily a result of higher earnings in the Exploration and Production segment, Gathering segment, Pipeline and Storage segment and Utility segment, as well as a lower loss in the All Other category. Lower earnings in the Energy Marketing segment, as well as a loss in the Corporate category, partially offset these increases. In the discussion that follows, all amounts used in the earnings discussions are after-tax amounts, unless otherwise noted. Earnings were impacted by the following event in 2018:

2018 Event

- A $103.5 million remeasurement of accumulated deferred income taxes and a lower statutory rate of 24.5% as a result of the 2017 Tax Reform Act.

2017 Compared with 2016

The Company's earnings were $283.5 million in 2017 compared to a loss of $291.0 million in 2016. The increase in earnings of $574.5 million was primarily a result of higher earnings in the Exploration and Production segment and Gathering segment. Lower earnings in the Pipeline and Storage segment, Utility segment and Energy Marketing segment, as well as losses in the Corporate and All Other categories, partially offset these increases. Earnings were impacted by the following events in 2016:

2016 Events

- Non-cash impairment charges of $948.3 million ($550.0 million after tax) recorded during 2016 for the Exploration and Production segment’s oil and gas producing properties.
- Joint development agreement professional fees of $4.6 million recorded in the Exploration and Production segment. The joint development agreement professional fees incurred were related to professional services associated with the Marcellus Shale drilling joint development agreement with IOG executed on December 1, 2015 and subsequently extended on June 13, 2016.

Earnings (Loss) by Segment

	Year Ended September 30		
	2018	2017	2016
		(Thousands)	
Exploration and Production	$ 180,632	$ 129,326	$ (452,842)
Pipeline and Storage	97,246	68,446	76,610
Gathering	83,519	40,377	30,499
Utility	51,217	46,935	50,960
Energy Marketing	373	1,509	4,348
Total Reported Segments	412,987	286,593	(290,425)
All Other	(112)	(342)	778
Corporate	(21,354)	(2,769)	(1,311)
Total Consolidated	$ 391,521	$ 283,482	$ (290,958)

EXPLORATION AND PRODUCTION

Revenues

Exploration and Production Operating Revenues

	Year Ended September 30		
	2018	2017	2016
		(Thousands)	
Gas (after Hedging)	$ 410,716	$ 462,976	$ 433,357
Oil (after Hedging)	148,693	147,599	169,263
Gas Processing Plant	4,036	3,181	2,411
Other	1,102	843	2,082
Operating Revenues	$ 564,547	$ 614,599	$ 607,113

Production

	Year Ended September 30		
	2018	2017	2016
Gas Production *(MMcf)*			
Appalachia	160,499	154,093	140,457
West Coast	2,407	2,995	3,090
Total Production	162,906	157,088	143,547
Oil Production *(Mbbl)*			
Appalachia	4	4	28
West Coast	2,531	2,736	2,895
Total Production	2,535	2,740	2,923

Average Prices

	Year Ended September 30		
	2018	2017	2016
Average Gas Price/Mcf			
Appalachia	$ 2.36	$ 2.52	$ 1.94
West Coast	$ 4.86	$ 4.00	$ 3.25
Weighted Average	$ 2.40	$ 2.55	$ 1.97
Weighted Average After Hedging(1)	$ 2.52	$ 2.95	$ 3.02
Average Oil Price/Barrel (Bbl)			
Appalachia	$ 57.76	$ 48.27	$ 52.15
West Coast	$ 66.39	$ 46.14	$ 35.26
Weighted Average	$ 66.38	$ 46.18	$ 35.42
Weighted Average After Hedging(1)	$ 58.66	$ 53.87	$ 57.91

(1) Refer to further discussion of hedging activities below under "Market Risk Sensitive Instruments" and in Note G — Financial Instruments in Item 8 of this report.

2018 Compared with 2017

Operating revenues for the Exploration and Production segment decreased $50.1 million in 2018 as compared with 2017. Gas production revenue after hedging decreased $52.3 million primarily due to a $0.43 per Mcf decrease in the weighted average price of gas after hedging partially offset by a 5.8 Bcf increase in gas production. The increase in production was primarily due to new Marcellus and Utica wells completed and connected to sales in the Western and Eastern Development Areas during the year coupled with a decrease in price-related curtailments during fiscal 2018 compared to fiscal 2017. These decreases to operating revenues were slightly offset by an increase in oil production revenue after hedging of $1.1 million. The increase in oil production revenue after hedging was due to a $4.79 per Bbl increase in the weighted average price of oil after hedging, partially offset by a 205 Mbbl decrease in crude oil production. The decrease in crude oil production was largely due to lower production in the West Coast region as a result of the sale of Seneca's Sespe properties in May 2018. In addition, gas processing plant revenue increased $0.9 million and other revenue increased $0.3 million.

Refer to further discussion of derivative financial instruments in the "Market Risk Sensitive Instruments" section that follows. Refer to the tables above for production and price information.

2017 Compared with 2016

Operating revenues for the Exploration and Production segment increased $7.5 million in 2017 as compared with 2016. Gas production revenue after hedging increased $29.6 million primarily due to a 13.5 Bcf increase in gas production partially offset by a $0.07 per Mcf decrease in the weighted average price of gas after hedging. The increase in production was primarily due to a significant decrease in price-related curtailments during fiscal 2017 compared to fiscal 2016. This was partially offset by the impact of a joint development agreement with IOG CRV - Marcellus, LLC (IOG) (lower net revenue interest in producing wells), production declines on wells in the Eastern Development Area (Tioga and Lycoming counties in Pennsylvania) and the expected impact of changing from a 3-drilling rig program to a 1-drilling rig program. For further discussion of the joint development agreement with IOG, refer to Item 8 at Note A — Summary of Significant Accounting Policies under the heading "Property, Plant and Equipment." In addition, gas processing plant revenue increased $0.8 million due to an increase in price and volumes. These increases to operating revenues were partially offset by a decrease in oil production revenue after hedging of $21.7 million due to a 183 Mbbl decrease in crude oil production coupled with a $4.04 per Bbl decrease in the weighted average price of oil after hedging. The decrease in crude oil production was largely due to the 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). In addition, other revenue decreased $1.2 million largely due to the impact of mark-to-market adjustments related to hedging ineffectiveness.

Earnings

2018 Compared with 2017

The Exploration and Production segment's earnings for 2018 were $180.6 million, compared with earnings of $129.3 million for 2017, an increase of $51.3 million. The increase in earnings was primarily attributable to lower income tax expense driven largely by the impact of the 2017 Tax Reform Act, which resulted in a remeasurement of accumulated deferred taxes ($73.7 million) and reduced the Company's federal tax rate resulting in lower income tax expense on current year earnings ($20.1 million). Offsetting these positive impacts on income tax expense were the combined impact of deferred state income tax adjustments recorded in the current and prior year which lowered earnings year over year ($8.1 million).

In addition to the net positive impact on earnings from lower income tax expense, fiscal 2018 earnings benefited from higher crude oil prices after hedging ($7.9 million), higher natural gas production ($11.1 million), lower production expenses ($2.1 million), lower other operating expenses ($0.3 million), lower other taxes ($0.7 million), and lower interest expense ($0.2 million). The decrease in production expense was largely due to the aforementioned sale of Seneca's Sespe properties in May 2018, coupled with the sales of unconventional wells to Pin Oak in September 2017 and sales of compressors to Midstream Company in March 2018. These decreases in production expense were partially offset by increased gathering and transportation costs in the Appalachian region.

These factors, which contributed to increased earnings during fiscal 2018 compared to fiscal 2017, were partially offset by lower natural gas prices after hedging ($45.1 million), lower crude oil production ($7.2 million), higher depletion expense ($7.6 million), and a loss recognized on reacquired debt ($0.6 million). The increase in depletion expense, which is computed using the units of production method, was primarily due to the increase in production coupled with a $0.05 per Mcfe increase in the depletion rate. During the fourth quarter of fiscal 2018, the Exploration and Production segment recognized a loss on the redemption of long-term debt for its share of the premium paid by the Company to redeem $250 million of the Company's 8.75% notes that were scheduled to mature in May 2019.

2017 Compared with 2016

The Exploration and Production segment's earnings for 2017 were $129.3 million, an increase of $582.1 million when compared with a loss of $452.8 million for 2016. The increase in earnings primarily reflected the non-recurrence of impairment charges for oil and gas producing properties ($550.0 million). It also reflected higher natural gas production ($26.6 million), lower depletion expense ($17.8 million), lower other operating expenses ($2.2 million), lower interest expense ($1.1 million), the non-recurrence of joint development agreement professional fees ($4.6 million) and lower income tax expense ($10.6 million). The decrease in depletion expense was primarily due to a lower level of capitalized costs as a result of the impairment charges recognized in fiscal 2015 and fiscal 2016. The decrease in other operating expenses was primarily due to a decrease in personnel costs coupled with a decrease in plugging and abandonment expense (as a result of the sale of Upper Devonian wells in Pennsylvania in June 2016), which was partially offset by a contract suspension payment to TransCanada related to transportation services for the Northern Access project. The decrease in interest expense was largely due to a decrease in the Exploration and Production segment's intercompany short-term borrowings. The decrease in income tax expense was largely due to an increase in anticipated firm transportation of natural gas to delivery points outside of Pennsylvania as a result of forecasted deliveries to the Atlantic Sunrise Pipeline. This had the effect of decreasing the effective tax rate used in the calculation of deferred tax expense. Income tax expense also decreased due to an enhanced oil recovery tax credit related to Seneca's California properties, which was applicable in fiscal 2017 as a result of relatively low domestic crude oil prices. The joint development agreement professional fees incurred were related to professional services associated with the Marcellus Shale drilling joint development agreement with IOG executed in December 2015 and extended in June 2016. These fees did not recur during fiscal 2017.

These factors, which contributed to increased earnings during fiscal 2017 compared to fiscal 2016, were partially offset by lower crude oil prices after hedging ($7.2 million), lower natural gas prices after hedging ($7.3 million), lower crude oil production ($6.9 million), higher production costs ($7.9 million) and higher other taxes ($1.1 million). The increase in production costs was largely due to an increase in transportation costs associated with higher gas production volume (mostly transported by Midstream Company) coupled with increased well repairs, equipment rentals, contract labor and steam fuel costs in the West Coast region, which will support production in future years. These were partially offset by lower repair and maintenance costs associated with operating wells in Appalachia (impacted by the sale of Upper Devonian related wells in June 2016). The increase in other taxes was largely due to higher impact fees related to Appalachian production in fiscal 2017 compared to fiscal 2016. Impact fees were significantly lower in fiscal 2016 as a result of IOG's reimbursement of such costs for years prior to fiscal 2016. The increase in other taxes also reflected an increase in Appalachian franchise taxes, partially offset by a decrease in Kern, Ventura and Coalinga County taxes in the West Coast region due to lower crude oil prices.

PIPELINE AND STORAGE

Revenues

Pipeline and Storage Operating Revenues

	Year Ended September 30		
	2018	2017	2016
		(Thousands)	
Firm Transportation	$ 222,908	$ 221,609	$ 229,895
Interruptible Transportation	1,422	1,690	3,995
	224,330	223,299	233,890
Firm Storage Service	74,486	69,963	70,351
Interruptible Storage Service	23	19	143
	74,509	69,982	70,494
Other	1,487	1,144	2,045
	$ 300,326	$ 294,425	$ 306,429

Pipeline and Storage Throughput — (MMcf)

	Year Ended September 30		
	2018	2017	2016
Firm Transportation	764,320	779,382	740,875
Interruptible Transportation	3,546	5,805	23,548
	767,866	785,187	764,423

2018 Compared with 2017

Operating revenues for the Pipeline and Storage segment increased $5.9 million in 2018 as compared with 2017. The increase in operating revenues was primarily due to demand charges for transportation service from Supply Corporation's Line D Expansion, which was placed in service on November 1, 2017, an increase in reservation charges for storage service from new storage contracts as a result of Supply Corporation's acquisition of the remaining interest in a jointly owned storage field and an increase in both transportation and storage revenues due to Supply Corporation's greenhouse gas and pipeline safety surcharge effective November 1, 2017. Partially offsetting these increases was 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 decreased by 17.3 Bcf in 2018 as compared with 2017. The decrease in transportation volume primarily reflects a reduction in capacity utilization by certain contract shippers combined with contract terminations. 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.

2017 Compared with 2016

Operating revenues for the Pipeline and Storage segment decreased $12.0 million in 2017 as compared with 2016. The decrease was primarily due to a decrease in transportation revenues of $10.6 million. The decline in transportation revenues was due partially to a 2% reduction in Supply Corporation's rates effective November 1, 2015 and an additional 2% reduction in Supply Corporation's rates effective November 1, 2016, both of which were required by the rate case settlement approved by FERC on November 13, 2015. The decrease also reflects reductions in Empire's rates effective July 1, 2016 as required by the rate case settlement approved by FERC on December 13, 2016 combined with a decline in demand charges for transportation services as a result of contract terminations and contract restructuring, as well as lower demand for short-term interruptible transportation service. Partially offsetting these decreases, transportation revenues benefited from a full year of revenue from Supply Corporation's Northern Access 2015 project, which was placed in service on an interim basis in November 2015 and became fully operational in December 2015, and transportation revenues also benefited from a full year of revenue from Empire's Tuscarora Lateral Project, which was placed in service in November 2015.

Transportation volume increased by 20.8 Bcf in 2017 as compared with 2016. The increase in transportation volume primarily reflects the impact of a full year of transportation service from the Northern Access 2015 project and the Tuscarora Lateral Project, both of which are discussed in the previous paragraph.

Earnings

2018 Compared with 2017

The Pipeline and Storage segment’s earnings in 2018 were $97.2 million, an increase of $28.8 million when compared with earnings of $68.4 million in 2017. The increase in earnings was primarily due to lower income tax expense ($25.8 million) combined with the earnings impact of higher transportation and storage revenues of $3.6 million, as discussed above, a decrease in interest expense ($1.5 million) and lower operating expenses ($0.4 million). Income tax expense was lower due to the remeasurement of accumulated deferred income taxes in the quarter ended December 31, 2017 ($14.1 million) combined with the current period earnings impact of the change in the federal tax rate from 35% to a blended rate of 24.5% for fiscal 2018 ($11.7 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 partially offset by an increase in pipeline integrity program expenses, increase in compressor station costs and increased personnel 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 contributors were slightly offset by higher income tax expense ($0.7 million) excluding the impact of the 2017 Tax Reform Act, an increase in depreciation expense ($1.5 million) and an increase in property taxes ($0.8 million). The increase in income taxes was a result of higher state taxes combined with a reduction in benefits associated with the tax sharing agreement with affiliated companies. The increase in depreciation expense was 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. The Company does not expect to renew the contract at existing rates given a change in market dynamics.

2017 Compared with 2016

The Pipeline and Storage segment’s earnings in 2017 were $68.4 million, a decrease of $8.2 million when compared with earnings of $76.6 million in 2016. The decrease in earnings was primarily due to the earnings impact of lower transportation revenues of $6.9 million, as discussed above, combined with higher operating expenses ($4.4 million), an increase in property taxes ($0.8 million) and a decrease in the allowance for funds used during construction (equity component) of $0.5 million. The increase in operating expenses primarily reflected an increase in compressor station costs due primarily to costs associated with the overhaul of two compressor stations, higher pension and other post-retirement benefit costs and increased personnel costs. The decrease in allowance for funds used during construction reflected the completion of Supply Corporation's Westside Expansion and Modernization Project, Supply Corporation's Northern Access 2015 project and Empire's Tuscarora Lateral Project in the first quarter of fiscal 2016. These earnings decreases were partially offset by a decrease in depreciation expense ($1.4 million) and lower income tax expense ($3.2 million). The decrease in depreciation expense was attributable to a decrease in Empire's depreciation rates associated with Empire's rate case settlement as discussed above offset partially by the incremental depreciation expense related to expansion projects that were placed in service within the last year. Income tax expense was lower due to provision-to-return adjustments combined with lower state taxes, an increase in benefits associated with the tax sharing agreement with affiliated companies and the adoption of the accounting guidance regarding stock-based compensation.

GATHERING

Revenues

Gathering Operating Revenues

	Year Ended September 30		
	2018	2017	2016
		(Thousands)	
Gathering	$ 107,856	$ 107,566	$ 89,073
Processing and Other Revenues	41	115	374
	$ 107,897	$ 107,681	$ 89,447

Gathering Volume — (MMcf)

	Year Ended September 30		
	2018	2017	2016
Gathered Volume	198,355	194,921	161,955

2018 Compared with 2017

Operating revenues for the Gathering segment increased $0.2 million in 2018 as compared with 2017. This slight increase was primarily due to an increase in gathered volume at Midstream Company's Covington, Trout Run, Clermont and Wellsboro gathering systems, largely offset by the net impact of changes made to rates charged by the Covington, Trout Run and Wellsboro gathering systems and the impact of the sale of the Mt. Jewett, Owls Nest and Tionesta gathering systems. The gathering systems at Covington, Trout Run, Clermont and Wellsboro had a combined net increase in gathered volume of 4.3 Bcf year over year, increasing revenues by $2.1 million. The 4.3 Bcf increase in gathered volume can be attributed to the net increase in Seneca's production. The change in gathering rates and the sale of the Mt. Jewett, Owls Nest and Tionesta gathering systems, all of which occurred in the second quarter of fiscal 2018, reduced operating revenues year over year by $1.1 million and $0.8 million, respectively.

2017 Compared with 2016

Operating revenues for the Gathering segment increased $18.2 million in 2017 as compared with 2016. This increase was due to an increase in gathering revenues driven by a 33.0 Bcf increase in gathered volume. The overall increase in gathered volume was due to a 22.5 Bcf increase in gathered volume on Clermont, a 4.7 Bcf increase in gathered volume on Wellsboro, a 3.0 Bcf increase in gathered volume on Trout Run and a 2.9 Bcf increase in gathered volume on Covington. The increases in the aforementioned volumes were largely due to increases in Seneca's Marcellus Shale production due to a significant decrease in price-related curtailments during fiscal 2017 compared to fiscal 2016.

Earnings

2018 Compared with 2017

The Gathering segment's earnings in 2018 were $83.5 million, an increase of $43.1 million when compared with earnings of $40.4 million in 2017. The increase in earnings was primarily attributable to lower income tax expense driven largely by the impact of the 2017 Tax Reform Act, which resulted in the remeasurement of accumulated deferred taxes ($34.5 million) and reduced the Company's federal tax rate resulting in lower income tax expense on current year earnings ($8.0 million). Additionally, tax planning and restructuring activities implemented during the year reduced the Gathering segment's deferred state income taxes and increased current year earnings ($2.3 million). These earnings increases were offset by higher operating expenses ($1.8 million) and higher depreciation expense ($0.7 million). The increase in operating expenses was due largely to the operation of new compression facilities along the Covington gathering system that were acquired from affiliate Seneca in March 2018, an increase in facilities and maintenance activity at the Clermont and Trout Run gathering systems, and a loss recognized on the sale of pipe materials. Depreciation expense increased due to higher plant balances, primarily for the Clermont and Trout Run gathering systems.

2017 Compared with 2016

The Gathering segment’s earnings in 2017 were $40.4 million, an increase of $9.9 million when compared with earnings of $30.5 million in 2016. The increase in earnings was mainly due to an increase in gathering revenues ($12.0 million). The increase in gathering revenues was due to the increases in gathered volume discussed above. These were partially offset by higher operating expenses ($1.8 million) and higher depreciation expense ($0.6 million). The increase in operating expenses were largely due to the ramp up in gathering operations as a result of increases in Seneca's Marcellus Shale production. An increase in gas plant balances (mostly in Clermont), led to an increase in depreciation expense.

UTILITY

Revenues

Utility Operating Revenues

	Year Ended September 30		
	2018	2017	2016
		(Thousands)	
Retail Revenues:			
Residential	$ 487,344	$ 435,357	$ 360,648
Commercial	67,134	58,988	44,994
Industrial	4,090	2,376	1,785
	558,568	496,721	407,427
Off-System Sales	358	3,997	1,877
Transportation	129,909	129,509	124,120
Other	(1,309)	9,744	10,723
	$ 687,526	$ 639,971	$ 544,147

Utility Throughput — million cubic feet (MMcf)

	Year Ended September 30		
	2018	2017	2016
Retail Sales:			
Residential	60,174	52,394	49,971
Commercial	9,187	7,927	7,247
Industrial	623	333	244
	69,984	60,654	57,462
Off-System Sales	141	1,301	1,243
Transportation	76,828	71,040	70,847
	146,953	132,995	129,552

Degree Days

Year Ended September 30		Normal		Actual	Percent (Warmer) Colder Than Normal(1)	Prior Year(1)
2018	Buffalo	6,617		6,391	(3.4)%	12.0 %
	Erie	6,147		5,976	(2.8)%	15.4 %
2017	Buffalo	6,617		5,708	(13.7)%	1.7 %
	Erie	6,147		5,179	(15.7)%	(0.1)%
2016	Buffalo	6,653	(2)	5,611	(15.7)%	(19.5)%
	Erie	6,181	(2)	5,182	(16.2)%	(21.3)%

(1) Percents compare actual degree days to normal degree days and actual degree days to actual prior year degree days.

(2) Normal degree day estimates changed to 6,653 for Buffalo and 6,181 for Erie as a result of updated information from the National Oceanic and Atmospheric Administration. In addition, normal degree days for 2016 reflect the fact that 2016 was a leap year.

2018 Compared with 2017

Operating revenues for the Utility segment increased $47.6 million in 2018 compared with 2017. The increase largely resulted from a $61.8 million increase in retail gas sales revenues. The increase in retail gas sales revenues was largely a result of higher volumes (due to colder weather) and an increase in the cost of gas sold (per Mcf). These increases were partially offset by a $3.6 million decrease in off-system sales (due to lower volumes) and an $11.1 million decrease in other revenues. Due to profit sharing with retail customers, the margins related to off-system sales are minimal. The $11.1 million decrease in other revenues was largely due to a $12.7 million refund provision recorded during 2018 to refund the net effect of the reduction in the federal income tax rate resulting from the 2017 Tax Reform Act to the Utility segment's customers in accordance with NYPSC and PaPUC regulatory orders.

2017 Compared with 2016

Operating revenues for the Utility segment increased $95.8 million in 2017 compared with 2016. The increase largely resulted from an $89.3 million increase in retail gas sales revenues. In addition, there was a $5.4 million increase in transportation revenues, and a $2.1 million increase in off-system sales (due to higher sales prices coupled with slightly higher volumes). Due to profit sharing with retail customers, the margins related to off-system sales are minimal. The increase in retail gas sales revenues was largely a result of an increase in the cost of gas sold (per Mcf) coupled with an increase in volumes due to higher usage. The increase in transportation revenues was due to the increase in the price paid by marketers to cash-out their imbalances and an increase in those imbalances owed to the Utility segment as transportation throughput was relatively flat.

Purchased Gas

The cost of purchased gas is the Company's single largest operating expense. Annual variations in purchased gas costs are attributed directly to changes in gas sales volume, the price of gas purchased and the operation of purchased gas adjustment clauses. Distribution Corporation recorded $306.1 million, $252.8 million and $166.2 million of Purchased Gas expense during 2018, 2017 and 2016, respectively. Under its purchased gas adjustment clauses in New York and Pennsylvania, Distribution Corporation is not allowed to profit from fluctuations in gas costs. Purchased gas expense recorded on the consolidated income statement matches the revenues collected from customers, a component of Operating Revenues on the consolidated income statement. Under mechanisms approved by the NYPSC in New York and the PaPUC in Pennsylvania, any difference between actual purchased gas costs and what has been collected from the customer is deferred on the consolidated balance sheet as either an asset, Unrecovered Purchased Gas Costs, or a liability, Amounts Payable to Customers. These deferrals are subsequently collected from the customer or passed back to the customer, subject to review by the NYPSC and the PaPUC. Absent disallowance of full recovery of Distribution Corporation's purchased gas costs, such costs do not impact the profitability of the Company. Purchased gas costs impact cash flow from operations due to the timing of recovery of such costs versus the actual purchased gas costs incurred during a particular period. Distribution Corporation's purchased gas adjustment clauses seek to mitigate this impact by adjusting revenues on either a quarterly or monthly basis.

Distribution Corporation contracts for firm long-term transportation and storage capacity with rights-of-first-refusal from nine upstream pipeline companies including Supply Corporation for transportation and storage and Empire for transportation. Distribution Corporation contracts for firm gas supplies on term and spot bases with various producers, marketers and one local distribution company to meet its gas purchase requirements. Additional discussion of the Utility segment's gas purchases appears under the heading "Sources and Availability of Raw Materials" in Item 1.

Earnings

2018 Compared with 2017

The Utility segment's earnings in 2018 were $51.2 million, an increase of $4.3 million when compared with earnings of $46.9 million in 2017. Higher earnings associated with the new rate order issued by the NYPSC effective April 1, 2017 ($2.8 million), the impact of colder weather in fiscal 2018 compared to fiscal 2017 ($5.2 million), lower interest expense ($1.1 million) and a decrease in property and other taxes ($0.7 million) were partially offset by the impact of regulatory adjustments ($3.9 million), higher operating expenses ($1.8 million) and the net impact of the 2017 Tax Reform Act, as discussed below. Lower earnings associated with regulatory adjustments are largely due to changes in the low income customer discount and payment assistance program implemented in the Utility segment's New York rate jurisdiction after the new rate order became effective on April 1, 2017. The increase in operating expenses is primarily due to higher amortization of environmental remediation costs that resulted from the new rate order combined with higher personnel costs and bad debt expense, partially offset by lower pension and other post-retirement benefit costs. The decrease in interest expense was largely due to lower interest rates on intercompany long-term borrowings.

The 2017 Tax Reform Act lowered the Company's statutory federal income tax rate, which resulted in lower income tax expense on the Utility segment's fiscal 2018 earnings ($7.8 million). The positive impact of the lower income taxes, however, was offset by a refund provision recorded during the year to refund the net effect of the lower federal income tax rate to the Utility segment's customers in accordance with NYPSC and PaPUC regulatory orders. The refund provision, which reduced other operating revenues, lowered earnings by $8.2 million.

The impact of weather variations on earnings in the Utility segment's New York rate jurisdiction is mitigated by that jurisdiction's weather normalization clause (WNC). The WNC in New York, which covers the eight-month period from October through May, has had a stabilizing effect on earnings for the New York rate jurisdiction. In addition, in periods of colder than normal weather, the WNC benefits the Utility segment's New York customers. For 2018, the WNC increased earnings by approximately $0.2 million, as the weather was warmer than normal. In 2017, the WNC increased earnings by approximately $4.3 million, as the weather was warmer than normal.

2017 Compared with 2016

The Utility segment's earnings in 2017 were $46.9 million, a decrease of $4.1 million when compared with earnings of $51.0 million in 2016. The decrease in earnings was largely attributable to higher operating expenses of $3.3 million (primarily due to higher personnel costs including the impact of post-implementation costs related to the replacement of the Utility segment's legacy mainframe system), higher depreciation expense of $2.6 million (largely due to higher plant balances including the impact of the legacy mainframe system replacement), a decrease in the allowance for funds used during construction (equity component) of $0.9 million (due to the May 2016 completion of the Utility segment's legacy mainframe system), higher income tax expense of $0.9 million (largely due to the aforementioned reduction in the allowance for funds used during construction in the current year which is non-taxable), lower interest income of $0.6 million (due to a lower balance in a regulatory asset and its impact on accrued income) and higher interest expense of $0.6 million (largely due to the impact of a regulatory adjustment coupled with a reduction in the allowance for borrowed funds used during construction due to the May 2016 completion of the Utility segment's legacy mainframe system). These were partially offset by the positive earnings impact associated with higher usage ($2.5 million) and the impact of regulatory adjustments ($1.9 million, including the $1.5 million margin impact related to the new rate order issued by the NYPSC effective April 1, 2017). Usage refers to consumption after factoring out any impact that weather may have had on consumption.

ENERGY MARKETING

Revenues

Energy Marketing Operating Revenues

	Year Ended September 30		
	2018	2017	2016
		(Thousands)	
Natural Gas (after Hedging)	$ 138,531	$ 129,317	$ 94,028
Other	43	63	434
	$ 138,574	$ 129,380	$ 94,462

Energy Marketing Volume

	Year Ended September 30		
	2018	2017	2016
Natural Gas — (MMcf)	42,262	38,901	39,849

2018 Compared with 2017

Operating revenues for the Energy Marketing segment increased $9.2 million in 2018 as compared with 2017. The increase was primarily a result of an increase in gas sales revenue due to an increase in volume sold to retail customers as a result of colder weather and additional business from new customers, partially offset by a lower average price of natural gas period over period.

2017 Compared with 2016

Operating revenues for the Energy Marketing segment increased $34.9 million in 2017 as compared with 2016. The increase was primarily due to an increase in gas sales revenue due to a higher average price of natural gas period over period, slightly offset by a decrease in volume sold to retail customers.

Earnings

2018 Compared with 2017

The Energy Marketing segment's earnings in 2018 were $0.4 million, a decrease of $1.1 million when compared with earnings of $1.5 million in 2017. This decrease in earnings was primarily attributable to lower margin of $1.3 million and higher income tax expense of $0.3 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. Income tax expense was higher primarily due to a remeasurement of accumulated deferred income taxes ($0.4 million), partially offset by a decline in current period income taxes as a result of the reduction in the federal tax rate from 35% to a blended rate of 24.5% ($0.1 million), both a result of the 2017 Tax Reform Act. The earnings decrease was slightly offset by lower operating expenses of $0.3 million, which primarily reflects lower pension costs and a decrease in advertising expenses.

2017 Compared with 2016

The Energy Marketing segment's earnings in 2017 were $1.5 million, a decrease of $2.8 million when compared with earnings of $4.3 million in 2016. This decrease in earnings was primarily attributable to lower margin of $2.6 million. The decrease in margin largely reflected a decline in average margin per Mcf primarily due to stronger natural gas prices at local purchase points relative to NYMEX-based sales contracts, combined with the margin impact associated with the decrease in volume sold to retail customers during the year ended September 30, 2017 compared to the year ended September 30, 2016.

ALL OTHER AND CORPORATE OPERATIONS

All Other and Corporate operations primarily includes the operations of Seneca's Northeast Division and corporate operations. Seneca's Northeast Division markets timber from its New York and Pennsylvania land holdings.

Earnings

2018 Compared with 2017

All Other and Corporate operations recorded a loss of $21.5 million in 2018, which was $18.4 million higher than the loss of $3.1 million in 2017. The increase in loss was primarily attributable to higher income tax expense ($19.1 million) and higher depreciation expense ($0.6 million). The increase in income tax expense was driven largely by the impact of the 2017 Tax Reform Act, which resulted in a remeasurement of accumulated deferred taxes ($18.4 million) and lowered the Company's federal tax rate, reducing the income tax benefit realized on the current year loss ($0.7 million). These decreases in earnings were partially offset by higher margins ($1.6 million) from the sale of standing timber by Seneca's Northeast division.

2017 Compared with 2016

All Other and Corporate operations recorded a loss of $3.1 million in 2017, which was $2.6 million higher than the loss of $0.5 million in 2016. The increase in loss was primarily due to higher operating expenses ($1.2 million) largely due to higher personnel costs, higher income tax expense ($0.5 million) and lower margins ($1.0 million) from the sale of standing timber by Seneca's Northeast division.

INTEREST CHARGES

Although most of the variances in Interest Charges are discussed in the earnings discussion by segment above, the following is a summary on a consolidated basis (amounts below are pre-tax amounts):

Interest on long-term debt decreased $5.5 million in 2018 as compared to 2017. This decrease was primarily due to a decrease in the weighted average interest rate on long-term debt outstanding. The Company issued $300 million of 4.75% notes in August 2018 and $300 million of 3.95% notes in September 2017. The Company repaid $250 million of 8.75% notes in September 2018 and $300 million of 6.50% notes in October 2017.

Interest on long-term debt decreased $0.9 million in 2017 as compared to 2016. This decrease was primarily due to an increase in the capitalization of interest costs (mostly in Midstream Company) which decreased interest expense for the year ended September 30, 2017 as compared to the year ended September 30, 2016.

CAPITAL RESOURCES AND LIQUIDITY

The primary sources and uses of cash during the last three years are summarized in the following condensed statement of cash flows:

	Year Ended September 30		
	2018	2017	2016
		(Millions)	
Provided by Operating Activities	$ 613.6	$ 684.3	$ 589.0
Capital Expenditures	(584.0)	(450.3)	(581.6)
Net Proceeds from Sale of Oil and Gas Producing Properties	55.5	26.6	137.3
Other Investing Activities	(0.3)	1.2	(9.2)
Reduction of Long-Term Debt	(566.5)	—	—
Net Proceeds from Issuance of Long-Term Debt	295.0	295.2	—
Net Proceeds from Issuance of Common Stock	4.1	7.7	13.8
Dividends Paid on Common Stock	(143.3)	(139.1)	(134.8)
Excess Tax Benefits Associated with Stock-Based Compensation Awards	—	—	1.9
Net Increase (Decrease) in Cash and Temporary Cash Investments	$ (325.9)	$ 425.6	$ 16.4

OPERATING CASH FLOW

Internally generated cash from operating activities consists of net income available for common stock, adjusted for non-cash expenses, non-cash income and changes in operating assets and liabilities. Non-cash items include depreciation, depletion and amortization, impairment of oil and gas producing properties, deferred income taxes and stock-based compensation.

Cash provided by operating activities in the Utility and Pipeline and Storage segments may vary substantially from year to year 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.

Cash provided by operating activities in the Exploration and Production segment may vary from year to year 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 $613.6 million in 2018, a decrease of $70.7 million compared with the $684.3 million provided by operating activities in 2017. The decrease in cash provided by operating activities primarily reflects lower cash provided by operating activities in the Exploration and Production segment partially offset by an increase in cash provided by operating activities in the Utility segment. The decrease in the Exploration and Production segment was primarily due to lower cash receipts as a result of lower natural gas prices realized from natural gas production. The increase in the Utility segment was primarily due to the timing of gas cost recovery.

Net cash provided by operating activities totaled $684.3 million in 2017, an increase of $95.3 million compared with the $589.0 million provided by operating activities in 2016. The increase in cash provided by operating activities reflected higher cash provided by operating activities in the Exploration and Production and Gathering segments primarily due to higher cash receipts from natural gas production and gathering services in the Appalachian region.

INVESTING CASH FLOW

Expenditures for Long-Lived Assets

The Company's expenditures for long-lived assets, including non-cash capital expenditures, totaled $600.6 million, $462.1 million and $523.1 million in 2018, 2017 and 2016, respectively. The table below presents these expenditures:

	Year Ended September 30					
	2018		2017		2016	
			(Millions)			
Exploration and Production:						
Capital Expenditures(4)	$ 380.7	(1)	$ 253.1	(2)	$ 256.1	(3)
Pipeline and Storage:						
Capital Expenditures	92.8	(1)	95.3	(2)	114.3	(3)
Gathering:						
Capital Expenditures	61.7	(1)	32.6	(2)	54.3	(3)
Utility:						
Capital Expenditures	85.7	(1)	80.9	(2)	98.0	(3)
All Other and Corporate:						
Capital Expenditures	0.2		0.2		0.4	
Eliminations	(20.5)		—		—	
Total Expenditures	$ 600.6		$ 462.1		$ 523.1	

(1) 2018 capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $51.3 million, $21.9 million, $6.1 million and $9.5 million, respectively, of non-cash capital expenditures.

(2) 2017 capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $36.5 million, $25.1 million, $3.9 million and $6.7 million, respectively, of non-cash capital expenditures.

(3) 2016 capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $25.2 million, $18.7 million, $5.3 million and $11.2 million, respectively, of non-cash capital expenditures.

(4) The capital expenditures for the Exploration and Production segment for 2018, 2017 and 2016 do not include any proceeds received from the sale of oil and gas assets to IOG under the joint development agreement.

Exploration and Production

In 2018, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $353.5 million for the Appalachian region (including $240.8 million in the Marcellus Shale area and $99.1 million in the Utica Shale area) and $27.2 million for the West Coast region. These amounts included approximately $182.3 million spent to develop proved undeveloped reserves.

The Company entered into a purchase and sale agreement to sell its oil and gas properties in the Sespe Field area of Ventura County, California in October 2017 for $43 million. The Company completed the sale on May 1, 2018, effective as of October 1, 2017, receiving net proceeds of $38.2 million (included in Net Proceeds from Sale of Oil and Gas Producing Properties on the Consolidated Statement of Cash Flows for the year ended September 30, 2018). The net proceeds received by the Company were adjusted for production revenue and production expenses retained by the Company between the effective date of the sale and the closing date, resulting in lower proceeds from sale at the closing date. The divestiture of the Company's oil and gas properties in the Sespe Field reflects continuing efforts to focus West Coast development activities in the San Joaquin basin, particularly at the Midway Sunset field in Kern County, California. Under the full cost method of accounting for oil and natural gas properties, the sale proceeds were accounted for as a reduction of capitalized costs. Since the disposition did not significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to the cost center, the Company did not record any gain or loss from this sale.

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 jointly participate in a program to develop up to 75 Marcellus wells, with Seneca serving as program operator. IOG holds an 80% working interest in all of the joint development wells. In total, IOG has funded $305.5 million as of September 30, 2018 for its 80% working interest in the 75 joint development wells, which includes $181.2 million of cash ($137.3 million in fiscal 2016, $26.6 million in fiscal 2017 and $17.3 million in fiscal 2018) included in Net Proceeds from Sale of Oil and Gas Producing Properties on the Consolidated Statements of Cash Flows for fiscal 2016, fiscal 2017 and fiscal 2018, respectively. 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. For further discussion of the extended joint development agreement, refer to Item 8 at Note A — Summary of Significant Accounting Policies under the heading “Property, Plant and Equipment.”

In 2017, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $213.8 million for the Appalachian region (including $168.2 million in the Marcellus Shale area) and $39.3 million for the West Coast region. These amounts included approximately $101.1 million spent to develop proved undeveloped reserves.

In 2016, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $217.3 million for the Appalachian region (including $201.8 million in the Marcellus Shale area) and $38.8 million for the West Coast region. These amounts included approximately $92.8 million spent to develop proved undeveloped reserves.

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

Pipeline and Storage

The majority of the Pipeline and Storage segment’s capital expenditures for 2018 were 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 2018 include expenditures related to Supply Corporation's Line D Expansion project ($14.5 million), as discussed below.

The majority of the Pipeline and Storage segment’s capital expenditures for 2017 were 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 2017 included expenditures related to Empire and Supply Corporation's Northern Access project ($22.1 million) and Supply Corporation's Line D Expansion project ($14.4 million).

The majority of the Pipeline and Storage segment’s capital expenditures for 2016 were mainly for expenditures related to Empire and Supply Corporation's Northern Access project ($26.7 million), Supply Corporation's Northern Access 2015 project ($13.1 million), Supply Corporation's Westside Expansion and Modernization project ($11.1 million), Supply Corporation's Line D Expansion project ($10.4 million) and Empire and Supply Corporation's Tuscarora Lateral project ($7.6 million). In addition, the Pipeline and Storage segment capital expenditures for 2016 also included additions, improvements and replacements to this segment’s transmission and gas storage systems.

Gathering

The majority of the Gathering segment's capital expenditures for 2018 were for the purchase of two compressor stations for Midstream Company's Covington Gathering System as well as the continued buildout of Midstream Company's Trout Run Gathering System and Midstream Company's Clermont Gathering System, both of which are discussed below. Midstream Company spent $27.0 million and $14.8 million, respectively, in 2018 on the development of the Trout Run and Clermont gathering systems.

The majority of the Gathering segment's capital expenditures for 2017 and 2016 were for the construction and/or continued buildout of Midstream Company's Clermont Gathering System. Midstream Company spent $21.7 million in 2017 and $43.2 million in 2016 for the development of this system.

Utility

The majority of the Utility segment's capital expenditures for 2018, 2017 and 2016 were made for main and service line improvements and replacements, as well as main extensions. The capital expenditures for 2016 included $16.4 million related to the replacement of the Utility segment's customer information system, which was placed in service in May 2016.

Estimated Capital Expenditures

The Company's estimated capital expenditures for the next three years are:

	Year Ended September 30		
	2019	2020	2021
		(Millions)	
Exploration and Production(1)	$ 480	$ 510	$ 485
Pipeline and Storage	135	225	275
Gathering	60	75	45
Utility	95	95	95
All Other	—	—	—
	$ 770	$ 905	$ 900

(1) Includes estimated expenditures for the years ended September 30, 2019, 2020 and 2021 of approximately $210 million, $123 million and $64 million, respectively, to develop proved undeveloped reserves. The Company is committed to developing its proved undeveloped reserves within five years as required by the SEC's final rule on Modernization of Oil and Gas Reporting.

Exploration and Production

Estimated capital expenditures in 2019 for the Exploration and Production segment include approximately $445 million for the Appalachian region and $35 million for the West Coast region.

Estimated capital expenditures in 2020 for the Exploration and Production segment include approximately $465 million for the Appalachian region and $45 million for the West Coast region.

Estimated capital expenditures in 2021 for the Exploration and Production segment include approximately $450 million for the Appalachian region and $35 million for the West Coast region.

Pipeline and Storage

Capital expenditures for the Pipeline and Storage segment in 2019 through 2021 are expected to include: construction of new pipeline and compressor stations to support expansion projects, the replacement of transmission and storage lines, the reconditioning of storage wells and improvements of compressor stations. Expansion projects where the Company has begun to make significant investments of preliminary survey and investigation costs and/or where shipper agreements have been executed are described below.

In 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 completed and continue to pursue 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 (the “Northern Access project”). The Northern Access project would provide an outlet to Dawn-indexed markets in Canada and to the TGP line serving the U.S. Northeast. The Northern Access project involves the construction of approximately 99 miles of largely 24” pipeline and approximately 27,500 horsepower of compression on the two systems. 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. On August 6, 2018, the FERC issued an Order finding that the NYDEC exceeded the statutory time frame to take action under the Clean Water Act and, therefore, waived its opportunity to approve or deny the Water Quality Certification. Rehearing requests have been filed at FERC. The Company remains committed to the project. In light of these pending legal actions and the need to complete necessary project development activities in advance of construction, the target in-service date for the project is expected to be no earlier than the first half of fiscal 2022. The Company will update the $500 million preliminary cost estimate when there is further clarity on that date. As of September 30, 2018, approximately $76.2 million has been spent on the Northern Access project, including $23.0 million that has been spent to study the project, for which no reserve has been established. The remaining $53.2 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 included construction of a new 4,140 horsepower Keelor Compressor Station and modifications to the Bowen compressor station. The project also provides system modernization benefits. As of September 30, 2018, approximately $29.0 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 September 30, 2018.

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”). This project is fully subscribed under long term agreements. Empire filed a Section 7(c) application with the FERC in February 2018. The Empire North Project has a projected in-service date in the second half of fiscal 2020 and an estimated capital cost of approximately $145 million. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above. As of September 30, 2018, approximately $4.3 million has been spent to study this project, all of which has been included in Deferred Charges on the Consolidated Balance Sheet at September 30, 2018.

Supply Corporation has entered into a foundation shipper Precedent Agreement to provide incremental natural gas transportation services from Line N to the ethane 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. Supply Corporation filed a prior notice application with FERC on March 23, 2018 and was authorized to pursue the project under its blanket certificate as of May 30, 2018. The proposed in-service date for this project is as early as July 1, 2019 at an estimated capital cost of approximately $23 million. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above. As of September 30, 2018, approximately $2.2 million has been capitalized as Construction Work in Progress for this project.

Supply Corporation is currently in the pre-filing process at FERC for its FM100 Project, which will upgrade 1950's era pipeline in northwestern Pennsylvania and create approximately 330,000 Dth per day of additional capacity on its system in Pennsylvania from a receipt point with NFG Midstream Clermont, LLC in McKean County, Pennsylvania to the Transcontinental Gas Pipe Line Company, LLC ("Transco") system at Leidy, Pennsylvania. A precedent agreement has been executed by Supply Corporation and Transco whereby this additional capacity is expected to be leased by Transco, and will be part of the capacity Transco will offer in connection with its Leidy South expansion project that will make available capacity from receipt points along its Leidy Line to Zone 6 markets. Seneca will be an anchor shipper on Transco's project, providing Seneca with an outlet to premium markets for its Marcellus and Utica production from both the Clermont-Rich Valley and Trout Run-Gamble areas. The FM100 Project has a target in-service date in late calendar 2021 and a preliminary cost estimate of approximately $280 million. The majority of these expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above, with a small amount of the expenditures estimated to extend into fiscal 2022. As of September 30, 2018, approximately $1.4 million has been spent to study this project, all of which has been included in Deferred Charges on the Consolidated Balance Sheet at September 30, 2018.

Gathering

The majority of the Gathering segment capital expenditures in 2019 through 2021 are expected to be for construction and expansion of gathering systems, as discussed below.

NFG Midstream Clermont, LLC, a wholly owned subsidiary of Midstream Company, 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 Seneca's long-term plans. Estimated capital expenditures in 2019 through 2021 include anticipated expenditures in the range of $40 million to $70 million for the continued expansion of the Clermont Gathering System. As of September 30, 2018, the Company has spent approximately $296.1 million in costs related to this project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2018.

NFG Midstream Trout Run, LLC, a wholly owned subsidiary of Midstream Company, 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. Estimated capital expenditures in 2019 through 2021 include anticipated expenditures in the range of $50 million to $90 million for the continued expansion of the Trout Run Gathering System. As of September 30, 2018, the Company has spent approximately $204.4 million in costs related to this project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2018.

NFG Midstream Wellsboro, LLC, a wholly owned subsidiary of Midstream Company, continues to develop its Wellsboro Gathering System in Tioga County, Pennsylvania. Estimated capital expenditures in 2019 through 2021 include anticipated expenditures in the range of $40 million to $70 million for the continued expansion of the Wellsboro Gathering System. The Company has spent approximately $9.4 million in costs related to this project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2018.

Utility

Capital expenditures for the Utility segment in 2019 through 2021 are expected to be concentrated in the areas of main and service line improvements and replacements and, to a lesser extent, the purchase of new equipment.

Project Funding

Over the past two years, 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 as well as proceeds received from the sale of oil and gas assets. 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 2019 to help meet its capital expenditures needs. The level of short-term and long-term borrowings will depend upon the amount 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 September 30, 2018 or September 30, 2017, nor was there any short-term debt outstanding during the year ended September 30, 2018. 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 October 25, 2018, the Company entered into a Fourth Amended and Restated Credit Agreement (Credit Agreement) with a syndicate of 12 banks. This Credit Agreement provides a $750.0 million multi-year unsecured committed revolving credit facility through October 25, 2023. The Company also has an uncommitted line of credit with a financial institution for general corporate purposes. Borrowings under this uncommitted line of credit would be made at competitive market rates. The uncommitted credit line is revocable at the option of the financial institution and is reviewed on an annual basis. The Company anticipates that its uncommitted line of credit generally will be renewed or substantially replaced by a similar line. Other financial institutions may also provide the Company with uncommitted or discretionary lines of credit in the future.

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. For purposes of calculating the debt to capitalization ratio, the Company's total capitalization will be increased by adding back 50% of the aggregate after-tax amount of non-cash charges directly arising from any ceiling test impairment occurring on or after July 1, 2018, not to exceed $250 million. At September 30, 2018, the Company's debt to capitalization ratio (as calculated under the facility) was .52. The constraints specified in the Credit Agreement would have permitted an additional $1.46 billion in short-term and/or long-term debt to be outstanding at September 30, 2018 (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 September 30, 2018, the Company did not have any debt outstanding under the Credit Agreement.

On August 17, 2018, the Company issued $300.0 million of 4.75% notes due September 1, 2028. After deducting underwriting discounts, commissions and other debt issuance costs, the net proceeds to the Company amounted to $295.0 million. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of a change in control and a ratings downgrade to a rating below investment grade. Additionally, the interest rate payable on the notes will be subject to adjustment from time to time, with a maximum of 2.00%, if certain change of control events involving a material subsidiary result in a downgrade of the credit rating assigned to the notes to below investment grade (or if the credit rating assigned to the notes is subsequently upgraded). The proceeds of this debt issuance were used for general corporate purposes, including the redemption of $250.0 million of 8.75% notes on September 7, 2018 that were scheduled to mature in May 2019. The Company redeemed those notes for $259.5 million, plus accrued interest.

On September 27, 2017, the Company issued $300.0 million of 3.95% notes due September 15, 2027. After deducting underwriting discounts, commissions and other debt issuance costs, the net proceeds to the Company amounted to $295.2 million. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of a change in control and a ratings downgrade to a rating below investment grade. Additionally, the interest rate payable on the notes will be subject to adjustment from time to time, with a maximum of 2.00%, if certain change of control events involving a material subsidiary result in a downgrade of the credit rating assigned to the notes to below investment grade (or if the credit rating assigned to the notes is subsequently upgraded). The proceeds of this debt issuance were used to redeem $300.0 million of the Company's 6.50% notes on October 18, 2017 that were scheduled to mature in April 2018 and were classified as Current Portion of Long-Term Debt at September 30, 2017. The Company redeemed those notes for $307.0 million, plus accrued interest.

None of the Company’s long-term debt at September 30, 2018 had a maturity date within the next twelve-months. As discussed above, the Current Portion of Long-Term Debt at September 30, 2017 consisted of $300.0 million aggregate principal amount of 6.50% notes that were scheduled to mature in April 2018.

The Company’s embedded cost of long-term debt was 4.69% and 5.34% at September 30, 2018 and September 30, 2017, respectively. Refer to “Interest Rate Risk” in this Item for a more detailed breakdown of the Company’s embedded cost of long-term debt.

Under the Company’s existing indenture covenants at September 30, 2018, the Company would have been permitted to issue up to a maximum of $714.0 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 $99.0 million (or 4.6%) of the Company’s long-term debt (as of September 30, 2018) 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 $45.5 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.

CONTRACTUAL OBLIGATIONS

The following table summarizes the Company's expected future contractual cash obligations as of September 30, 2018, and the twelve-month periods over which they occur:

	Payments by Expected Maturity Dates						
	2019	2020	2021	2022	2023	Thereafter	Total
	(Millions)						
Long-Term Debt, including interest expense(1)	$ 100.1	$ 100.1	$ 100.1	$ 579.7	$ 611.8	$ 1,265.1	$ 2,756.9
Operating Lease Obligations	$ 18.6	$ 4.6	$ 4.0	$ 3.2	$ 2.7	$ 12.4	$ 45.5
Purchase Obligations:							
Gas Purchase Contracts(2)	$ 220.3	$ 20.8	$ 5.4	$ 0.2	$ —	$ —	$ 246.7
Transportation and Storage Contracts(3)	$ 77.6	$ 82.1	$ 81.2	$ 152.3	$ 162.8	$ 1,606.0	$ 2,162.0
Hydraulic Fracturing and Fuel Obligations	$ 86.2	$ 24.8	$ —	$ —	$ —	$ —	$ 111.0
Pipeline, Compressor and Gathering Projects	$ 105.1	$ 6.8	$ 6.1	$ 5.1	$ 3.4	$ 13.3	$ 139.8
Other	$ 45.7	$ 23.3	$ 16.5	$ 10.5	$ 8.6	$ 27.4	$ 132.0

(1) Refer to Note E — Capitalization and Short-Term Borrowings, as well as the table under Interest Rate Risk in the Market Risk Sensitive Instruments section below, for the amounts excluding interest expense.

(2) Gas prices are variable based on the NYMEX prices adjusted for basis.

(3) Transportation service contractual obligations include the following precedent agreements executed by the Exploration and Production segment for transportation of Appalachian gas: $33.1 million for 2019, $35.9 million for 2020, $35.8 million for 2021, $108.2 million for 2022, $119.3 million for 2023 and $1,556.2 million thereafter.

The Company has other long-term obligations recorded on its Consolidated Balance Sheets that are not reflected in the table above. Such long-term obligations include pension and other post-retirement liabilities, asset retirement obligations, deferred income tax liabilities, various regulatory liabilities, derivative financial instrument liabilities and other deferred credits (the majority of which consist of liabilities for non-qualified benefit plans, deferred compensation liabilities, environmental liabilities and workers compensation liabilities).

The Company has made certain other guarantees on behalf of its subsidiaries. The guarantees relate primarily to: (i) obligations under derivative financial instruments, which are included on the Consolidated Balance Sheets in accordance with the authoritative guidance (see Item 7, MD&A under the heading "Critical Accounting Estimates - Accounting for Derivative Financial Instruments"); (ii) NFR obligations to purchase gas or to purchase gas transportation/storage services where the amounts due on those obligations each month are included on the Consolidated Balance Sheets as a current liability; and (iii) other obligations which are reflected on the Consolidated

Balance Sheets. The Company believes that the likelihood it would be required to make payments under the guarantees is remote, and therefore has not included them in the table above.

OTHER MATTERS

In addition to the environmental and other matters discussed in this Item 7 and in Item 8 at Note I — Commitments and Contingencies, 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.

The Company has a tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan). The Company has been making contributions to the Retirement Plan over the last several years and anticipates that it will continue making contributions to the Retirement Plan. During 2018, the Company contributed $33.0 million to the Retirement Plan. The Company anticipates that the annual contribution to the Retirement Plan in 2019 will be in the range of $29.0 million to $35.0 million. The Company expects that all subsidiaries having employees covered by the Retirement Plan will make contributions to the Retirement Plan. The funding of such contributions will come from amounts collected in rates in the Utility and Pipeline and Storage segments or through cash on hand, cash from operations or short-term borrowings.

The Company provides health care and life insurance benefits (other post-retirement benefits) for a majority of its retired employees. The Company has established VEBA trusts and 401(h) accounts for its other post-retirement benefits. The Company has been making contributions to its VEBA trusts and/or 401(h) accounts over the last several years and anticipates that it will continue making contributions to the VEBA trusts and/or 401(h) accounts. During 2018, the Company contributed $2.8 million to its VEBA trusts. In addition, the Company made direct payments of $0.1 million to retirees not covered by the VEBA trusts and 401(h) accounts during 2018. The Company anticipates that the annual contribution to its VEBA trusts in 2019 will be in the range of $2.5 million to $4.0 million. The funding of such contributions will come from amounts collected in rates in the Utility and Pipeline and Storage segments.

MARKET RISK SENSITIVE INSTRUMENTS

Energy Commodity Price Risk

The Company uses various derivative financial instruments (derivatives), including price swap agreements and futures contracts, as part of the Company's overall energy commodity price risk management strategy in its Exploration and Production and Energy Marketing segments. Under this strategy, the Company manages a portion of the market risk associated with fluctuations in the price of natural gas and crude oil, thereby attempting to provide more stability to operating results. The Company has operating procedures in place that are administered by experienced management to monitor compliance with the Company's risk management policies. The derivatives are not held for trading purposes. The fair value of these derivatives, as shown below, represents the amount that the Company would receive from, or pay to, the respective counterparties at September 30, 2018 to terminate the derivatives. However, the tables below and the fair value that is disclosed do not consider the physical side of the natural gas and crude oil transactions that are related to the financial 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 the Company reduces its use of hedging transactions as a result of final regulations to be issued by the CFTC, results of operations may become more volatile and 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 the Company violate any laws or regulations applicable to our hedging activities, it 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 September 30, 2018, the Company determined that nonperformance risk would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty's (assuming the derivative is in a gain position) or the Company's (assuming the derivative is in a loss position) credit default swaps rates.

The following tables disclose natural gas and crude oil price swap information by expected maturity dates for agreements in which the Company receives a fixed price in exchange for paying a variable price as quoted in various national natural gas publications or on the NYMEX. Notional amounts (quantities) are used to calculate the contractual payments to be exchanged under the contract. The weighted average variable prices represent the weighted average settlement prices by expected maturity date as of September 30, 2018. At September 30, 2018, the Company had not entered into any natural gas or crude oil price swap agreements extending beyond 2024.

Natural Gas Price Swap Agreements

	Expected Maturity Dates						
	2019	2020	2021	2022	2023	2024	Total
Notional Quantities (Equivalent Bcf)	85.7	25.3	5.4	0.2	0.7	0.2	117.5
Weighted Average Fixed Rate (per Mcf)	$ 3.06	$ 3.15	$ 3.12	$ 2.93	$ 3.03	$ 3.04	$ 3.08
Weighted Average Variable Rate (per Mcf)	$ 2.96	$ 2.75	$ 2.77	$ 2.72	$ 2.74	$ 2.86	$ 2.90

Of the total Bcf above, 2.0 Bcf is accounted for as fair value hedges at a weighted average fixed rate of $3.07 per Mcf. The remaining 115.5 Bcf are accounted for as cash flow hedges at a weighted average fixed rate of $3.09 per Mcf.

At September 30, 2018, the Company had long (purchased) swaps covering 2.1 Bcf extending through 2024 at a weighted average fixed rate of $3.05 per Mcf and a weighted average settlement rate of $2.81 per Mcf. The Company had short (sold) swaps covering 115.4 Bcf extending through 2021 at a weighted average fixed rate of $3.08 per Mcf and a weighted average settlement rate of $2.90 per Mcf at September 30, 2018. At September 30, 2018, the Company would have received from its respective counterparties an aggregate of approximately $19.0 million to terminate the natural gas price swap agreements outstanding at that date.

At September 30, 2017, the Company had natural gas price swap agreements covering 114.0 Bcf at a weighted average fixed rate of $3.32 per Mcf, which included long (purchased) swaps covering 2.0 Bcf extending through 2022 at a weighted average fixed rate of $3.45 per Mcf and a weighted average settlement rate of $3.09 per Mcf and short (sold) swaps covering 112.0 Bcf extending through 2020 at a weighted average fixed rate of $3.31 per Mcf and a weighted average settlement rate of $3.06 per Mcf.

Crude Oil Price Swap Agreements

	Expected Maturity Dates				
	2019	**2020**	**2021**	**2022**	**Total**
Notional Quantities (Equivalent Bbls)	1,812,000	1,188,000	732,000	456,000	4,188,000
Weighted Average Fixed Rate (per Bbl)	$ 57.57	$ 59.96	$ 61.61	$ 56.97	$ 58.89
Weighted Average Variable Rate (per Bbl)	$ 75.54	$ 73.98	$ 70.48	$ 66.45	$ 73.23

At September 30, 2018, the Company would have paid its respective counterparties an aggregate of approximately $57.3 million to terminate the crude oil price swap agreements outstanding at that date.

At September 30, 2017, the Company had crude oil price swap agreements covering 3,459,000 Bbls at a weighted average fixed rate of $53.38 per Bbl.

Futures Contracts

The following table discloses the net contract volume purchased (sold), weighted average contract prices and weighted average settlement prices by expected maturity date for futures contracts used to manage natural gas price risk. At September 30, 2018, the Company did not hold any futures contracts with maturity dates extending beyond 2023.

	Expected Maturity Dates					
	2019	**2020**	**2021**	**2022**	**2023**	**Total**
Net Contract Volume Purchased (Sold) (Equivalent Bcf)	8.3	7.8	3.7	1.5	0.2	21.5
Weighted Average Contract Price (per Mcf)	$ 3.05	$ 2.93	$ 2.88	$ 2.89	$ 2.93	$ 2.98
Weighted Average Settlement Price (per Mcf)	$ 3.06	$ 2.84	$ 2.79	$ 2.75	$ 2.79	$ 2.94

At September 30, 2018, the Company had long (purchased) contracts covering 26.8 Bcf of gas extending through 2023 at a weighted average contract price of $2.95 per Mcf and a weighted average settlement price of $2.90 per Mcf. Of this amount, 25.2 Bcf is accounted for as fair value hedges and are used by the Company's Energy Marketing segment to hedge against rising prices, a risk to which this segment is exposed due to the fixed price gas sales commitments that it enters into with certain residential, commercial, industrial, public authority and wholesale customers. The remaining 1.6 Bcf is accounted for as cash flow hedges used to hedge against rising prices related to anticipated gas purchases for potential injections into storage. The Company would have paid $1.4 million to terminate these contracts at September 30, 2018.

At September 30, 2018, the Company had short (sold) contracts covering 5.3 Bcf of gas extending through 2021 at a weighted average contract price of $3.15 per Mcf and a weighted average settlement price of $3.14 per Mcf. Of this amount, 4.7 Bcf is accounted for as cash flow hedges as these contracts relate to the anticipated sale of natural gas by the Company's Energy Marketing segment. The remaining 0.6 Bcf is accounted for as fair value hedges, the majority of which are used to hedge against falling prices, a risk to which the Energy Marketing segment is exposed due to the fixed price gas purchase commitments that it enters into with certain natural gas suppliers. The Company would have received less than $0.1 million to terminate these contracts at September 30, 2018.

At September 30, 2017, the Company had long (purchased) contracts covering 15.3 Bcf of gas extending through 2023 at a weighted average contract price of $3.15 per Mcf and a weighted average settlement price of $3.16 per Mcf.

At September 30, 2017, the Company had short (sold) contracts covering 3.5 Bcf of gas extending through 2020 at a weighted average contract price of $3.47 per Mcf and a weighted average settlement price of $3.37 per Mcf.

Foreign Exchange Risk

The Company uses 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. All of these transactions are forecasted.

The following table discloses foreign exchange contract information by expected maturity dates. The Company receives a fixed price in exchange for paying a variable price as noted in the Canadian to U.S. dollar forward exchange rates. Notional amounts (Canadian dollars) are used to calculate the contractual payments to be exchanged under contract. The weighted average variable prices represent the weighted average settlement prices by expected maturity date as of September 30, 2018. At September 30, 2018, the Company had not entered into any foreign currency exchange contracts extending beyond 2026.

	Expected Maturity Dates						
	2019	2020	2021	2022	2023	Thereafter	Total
Notional Quantities (Canadian Dollar in millions)	$ 17.0	$ 14.4	$ 12.9	$ 12.9	$ 11.8	$ 17.5	$ 86.5
Weighted Average Fixed Rate ($Cdn/$US)	$ 1.25	$ 1.24	$ 1.29	$ 1.28	$ 1.28	$ 1.26	$ 1.27
Weighted Average Variable Rate ($Cdn/$US)	$ 1.27	$ 1.27	$ 1.28	$ 1.27	$ 1.28	$ 1.26	$ 1.28

At September 30, 2018, absent other positions with the same counterparties, the Company would have paid its respective counterparties an aggregate of $0.5 million to terminate these foreign exchange contracts.

Refer to Item 8 at Note G — Financial Instruments for a discussion of the Company's exposure to credit risk related to its derivative financial instruments.

Interest Rate Risk

The fair value of long-term fixed rate debt is $2.1 billion at September 30, 2018. This fair value amount is not intended to reflect principal amounts that the Company will ultimately be required to pay. The following table presents the principal cash repayments and related weighted average interest rates by expected maturity date for the Company's long-term fixed rate debt:

	Principal Amounts by Expected Maturity Dates						
	2019	2020	2021	2022	2023	Thereafter	Total
				(Dollars in millions)			
Long-Term Fixed Rate Debt	$ —	$ —	$ —	$ 500.0	$ 549.0	$ 1,100.0	$ 2,149.0
Weighted Average Interest Rate Paid	—	—	—	4.9%	4.1%	4.8%	4.7%

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

Distribution Corporation's current delivery rates in its New York jurisdiction were approved by the NYPSC in an order issued on April 20, 2017 with rates becoming effective May 1, 2017. 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. Briefs were filed and the Appellate Division has scheduled oral argument for its January 2019 term. The Company cannot predict the outcome of the appeal at this time.

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. The order stated the NYPSC's intent to ensure that the net benefits resulting from tax reform were preserved for ratepayers.

Pursuant to the order, a technical conference was held with the utilities in February 2018, and the New York Department of Public Service Staff subsequently issued a proposal for accounting and ratemaking treatment of the tax changes. On August 9, 2018, the NYPSC issued an Order Determining Rate Treatment of Tax Changes in this proceeding directing utilities to make compliance filings effective October 1, 2018 to begin providing sur-credits to customers reflecting tax savings associated with the 2017 Tax Reform Act. The order did not allow Distribution Corporation recovery for the improvements to the Company's imputed equity ratio directly resulting from the recent federal tax rate reduction. In compliance with that order, Distribution Corporation filed the necessary tariff amendments to implement the sur-credit effective October 1, 2018 subject to full reservation of rights. Distribution Corporation is currently evaluating the possibility of seeking judicial review of the order. On June 4, 2018, Distribution Corporation filed a petition with the NYPSC regarding Distribution Corporation's proposed disposition of net federal income tax savings resulting from the 2017 Tax Reform Act. That petition sought certain relief including recovery for the improvements to the Company's imputed equity ratio. It is possible that the NYPSC will deny Distribution Corporation's request for recovery of improvements to the Company's imputed equity ratio as was done in the August 9 order. Refer to Item 8 at Note D — Income Taxes for further discussion of the 2017 Tax Reform Act.

Pennsylvania Jurisdiction

Distribution Corporation's Pennsylvania jurisdiction delivery rates are being charged to customers in accordance with a rate settlement approved by the PaPUC. The rate settlement does not specify any requirement to file a future rate case.

In response to the issuance of the 2017 Tax Reform Act, the PaPUC issued an Order to Distribution Corporation on May 17, 2018, requiring that Distribution Corporation file a tariff supplement establishing temporary rates to implement refunds of 2.2% on customer rates beginning July 1, 2018. Distribution Corporation filed the necessary tariff supplement to implement such refunds effective July 1, 2018. In compliance with the May 17, 2018 PaPUC Order, Distribution Corporation filed a subsequent tariff supplement adjusting the negative surcharge in connection with the start of its new fiscal year, with the new rates effective October 1, 2018 and subject to reconciliation. Refer to Item 8 at Note D — Income Taxes for further discussion of the 2017 Tax Reform Act.

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. The FERC's July 2018 Final Rule in RM18-11-000, et. al, (Order No. 849) requires pipelines to file a new form isolating the tax impact to each pipeline and also to make an election regarding the action the pipelines will take to address the lower tax rates, one of which is filing a Section 4 rate proceeding. Supply Corporation is required to address the Order by December 6, 2018. At this point, the Company cannot predict the outcome of any action taken pursuant to the Order. Refer to Item 8 at Note D — Income Taxes for further discussion of the 2017 Tax Reform Act.

Empire filed a Section 4 rate case on June 29, 2018, proposing rate increases to be effective August 1, 2018. The proposed rates reflect an annual cost of service of $71.5 million, a rate base of $246.8 million, and a proposed return on equity of 14%. The FERC has accepted the filed rates and suspended the effective date of the increases until January 1, 2019, when the increased rates will be made effective, subject to refund. Lower storage rates were made effective August 1, 2018. Final rates are subject to approval by FERC. If the final approved rates exceed the rates that were in effect at June 29, 2018, but are less than rates put into effect subject to refund on January 1, 2019, Empire would be required to refund the difference between the rates collected subject to refund and the final approved rates, with interest at the FERC-approved rate. If the final approved rates are lower than the rates in effect at June 29, 2018, such lower rates will become effective prospectively from the date of the applicable FERC order, and refunds with interest will be limited to the difference between the rates collected subject to refund and the rates in effect at June 29, 2018. Since Empire has filed a rate case, it is not obligated to make a filing under RM18-11-000.

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 8 at Note I — Commitments and Contingencies under the heading “Environmental Matters.”

While changes in environmental laws and regulations could have an adverse financial impact on the Company, 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.

Environmental Regulation

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 from 1990 levels. Additionally, the plan targets that 50% of electric generation must come from renewable energy sources, in addition to a 600 trillion Btu increase in statewide energy efficiency from 2012 levels, both by 2030. Similarly, Pennsylvania has a methane reduction framework for the oil and gas industry which has resulted 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. Changing market conditions and new regulatory requirements, as well as unanticipated or inconsistent application of existing laws and regulations by administrative agencies, make it difficult to predict a long-term business impact across twenty or more years. Refer to the "Corporate Responsibility" section at the beginning of this Item 7, MD&A, for further discussion of environmental regulation matters.

NEW AUTHORITATIVE ACCOUNTING AND FINANCIAL REPORTING GUIDANCE

For discussion of the recently issued authoritative accounting and financial reporting guidance, refer to Item 8 at Note A — Summary of Significant Accounting Policies under the heading "New Authoritative Accounting and Financial Reporting Guidance."

EFFECTS OF INFLATION

Although the rate of inflation has been relatively low over the past few years, the Company's operations remain sensitive to increases in the rate of inflation because of its capital spending and the regulated nature of a significant portion of its business.

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

The Company is including the following cautionary statement in this Form 10-K 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," "believes," "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. 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;

5. Changes in the price of natural gas or oil;

6. Impairments under the SEC's full cost ceiling test for natural gas and oil reserves;

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;
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. The impact of potential information technology, cybersecurity or data security breaches;
20. Economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities or acts of war;
21. Significant differences between the Company's projected and actual capital expenditures and operating expenses; or
22. 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.

INDUSTRY AND MARKET DATA DISCLOSURE

The market data and certain other statistical information used throughout this Form 10-K are based on independent industry publications, government publications or other published independent sources. Some data is also based on the Company's good faith estimates. Although the Company believes these third-party sources are reliable and that the information is accurate and complete, it has not independently verified the information.

Item 7A *Quantitative and Qualitative Disclosures About Market Risk*

Refer to the "Market Risk Sensitive Instruments" section in Item 7, MD&A.

Item 8 ***Financial Statements and Supplementary Data***

Index to Financial Statements

Financial Statements and Financial Statement Schedule:

All other schedules are omitted because they are not applicable or the required information is shown in the Consolidated Financial Statements or Notes thereto.

Supplementary Data

Supplementary data that is included in Note K — Quarterly Financial Data (unaudited) and Note L — Supplementary Information for Oil and Gas Producing Activities (unaudited), appears under this Item, and reference is made thereto.

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of National Fuel Gas Company:

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the consolidated financial statements, including the related notes and financial statement schedule, of National Fuel Gas Company and its subsidiaries as listed in the accompanying index (collectively referred to as the "consolidated financial statements"). We also have audited the Company's internal control over financial reporting as of September 30, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of September 30, 2018 and September 30, 2017, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2018 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of September 30, 2018, based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Annual Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on the Company's consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PRICEWATERHOUSECOOPERS LLP

Buffalo, New York
November 16, 2018

We have served as the Company's auditor since 1941.

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND EARNINGS REINVESTED IN THE BUSINESS

	Year Ended September 30		
	2018	2017	2016
	(Thousands of dollars, except per common share amounts)		
INCOME			
Operating Revenues:			
Utility and Energy Marketing Revenues	$ 812,474	$ 755,485	$ 624,602
Exploration and Production and Other Revenues	569,808	617,666	611,766
Pipeline and Storage and Gathering Revenues	210,386	206,730	216,048
	1,592,668	1,579,881	1,452,416
Operating Expenses:			
Purchased Gas	337,822	275,254	147,982
Operation and Maintenance:			
Utility and Energy Marketing	200,780	199,293	192,512
Exploration and Production and Other	141,381	145,099	160,201
Pipeline and Storage and Gathering	100,245	98,200	88,801
Property, Franchise and Other Taxes	84,393	84,995	81,714
Depreciation, Depletion and Amortization	240,961	224,195	249,417
Impairment of Oil and Gas Producing Properties	—	—	948,307
	1,105,582	1,027,036	1,868,934
Operating Income (Loss)	487,086	552,845	(416,518)
Other Income (Expense):			
Other Income	4,697	7,043	9,820
Interest Income	6,766	4,113	4,235
Interest Expense on Long-Term Debt	(110,946)	(116,471)	(117,347)
Other Interest Expense	(3,576)	(3,366)	(3,697)
Income (Loss) Before Income Taxes	384,027	444,164	(523,507)
Income Tax Expense (Benefit)	(7,494)	160,682	(232,549)
Net Income (Loss) Available for Common Stock	391,521	283,482	(290,958)
EARNINGS REINVESTED IN THE BUSINESS			
Balance at Beginning of Year	851,669	676,361	1,103,200
	1,243,190	959,843	812,242
Dividends on Common Stock	(144,290)	(140,090)	(135,881)
Cumulative Effect of Adoption of Authoritative Guidance for Stock-Based Compensation	—	31,916	—
Balance at End of Year	$ 1,098,900	$ 851,669	$ 676,361
Earnings Per Common Share:			
Basic:			
Net Income (Loss) Available for Common Stock	$ 4.56	$ 3.32	$ (3.43)
Diluted:			
Net Income (Loss) Available for Common Stock	$ 4.53	$ 3.30	$ (3.43)
Weighted Average Common Shares Outstanding:			
Used in Basic Calculation	85,830,597	85,364,929	84,847,993
Used in Diluted Calculation	86,439,698	86,021,386	84,847,993

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended September 30		
	2018	2017	2016
	(Thousands of dollars)		
Net Income (Loss) Available for Common Stock	$ 391,521	$ 283,482	$ (290,958)
Other Comprehensive Income (Loss), Before Tax:			
Increase (Decrease) in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	6,225	15,661	(21,378)
Reclassification Adjustment for Amortization of Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans	9,704	13,433	10,068
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	132	4,008	1,524
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(74,103)	5,347	60,493
Reclassification Adjustment for Realized (Gains) Losses on Securities Available for Sale in Net Income	(430)	(1,575)	(1,374)
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	1,189	(81,605)	(220,919)
Other Comprehensive Income (Loss), Before Tax	(57,283)	(44,731)	(171,586)
Income Tax Expense (Benefit) Related to the Increase (Decrease) in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	1,582	6,175	(8,351)
Reclassification Adjustment for Income Tax Benefit Related to the Amortization of the Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans	2,437	4,929	3,723
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	(15)	1,505	592
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(22,547)	2,009	18,648
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Securities Available for Sale in Net Income	(158)	(580)	(527)
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Derivative Financial Instruments in Net Income	(955)	(34,286)	(86,659)
Income Taxes — Net	(19,656)	(20,248)	(72,574)
Other Comprehensive Loss	(37,627)	(24,483)	(99,012)
Comprehensive Income (Loss)	$ 353,894	$ 258,999	$ (389,970)

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED BALANCE SHEETS

	At September 30 2018	2017
	(Thousands of dollars)	
ASSETS		
Property, Plant and Equipment	$ 10,439,839	$ 9,945,560
Less — Accumulated Depreciation, Depletion and Amortization	5,462,696	5,271,486
	4,977,143	4,674,074
Current Assets		
Cash and Temporary Cash Investments	229,606	555,530
Hedging Collateral Deposits	3,441	1,741
Receivables — Net of Allowance for Uncollectible Accounts of $24,537 and $22,526, Respectively	141,498	112,383
Unbilled Revenue	24,182	22,883
Gas Stored Underground	37,813	35,689
Materials and Supplies — at average cost	35,823	33,926
Unrecovered Purchased Gas Costs	4,204	4,623
Other Current Assets	68,024	51,505
	544,591	818,280
Other Assets		
Recoverable Future Taxes	115,460	181,363
Unamortized Debt Expense	15,975	1,159
Other Regulatory Assets	112,918	174,433
Deferred Charges	40,025	30,047
Other Investments	132,545	125,265
Goodwill	5,476	5,476
Prepaid Post-Retirement Benefit Costs	82,733	56,370
Fair Value of Derivative Financial Instruments	9,518	36,111
Other	102	742
	514,752	610,966
Total Assets	$ 6,036,486	$ 6,103,320
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value; Authorized - 200,000,000 Shares; Issued and Outstanding - 85,956,814 Shares and 85,543,125 Shares, Respectively	$ 85,957	$ 85,543
Paid In Capital	820,223	796,646
Earnings Reinvested in the Business	1,098,900	851,669
Accumulated Other Comprehensive Loss	(67,750)	(30,123)
Total Comprehensive Shareholders' Equity	1,937,330	1,703,735
Long-Term Debt, Net of Current Portion and Unamortized Discount and Debt Issuance Costs	2,131,365	2,083,681
Total Capitalization	4,068,695	3,787,416
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	—	—
Current Portion of Long-Term Debt	—	300,000
Accounts Payable	160,031	126,443
Amounts Payable to Customers	3,394	—
Dividends Payable	36,532	35,500
Interest Payable on Long-Term Debt	19,062	35,031
Customer Advances	13,609	15,701
Customer Security Deposits	25,703	20,372
Other Accruals and Current Liabilities	132,693	111,889
Fair Value of Derivative Financial Instruments	49,036	1,103
	440,060	646,039
Deferred Credits		
Deferred Income Taxes	512,686	891,287
Taxes Refundable to Customers	370,628	95,739
Cost of Removal Regulatory Liability	212,311	204,630
Other Regulatory Liabilities	146,743	113,716
Pension and Other Post-Retirement Liabilities	66,103	149,079
Asset Retirement Obligations	108,235	106,395
Other Deferred Credits	111,025	109,019
	1,527,731	1,669,865
Commitments and Contingencies (Note I)	—	—
Total Capitalization and Liabilities	$ 6,036,486	$ 6,103,320

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2018	2017	2016
	(Thousands of dollars)		
Operating Activities			
Net Income (Loss) Available for Common Stock	$ 391,521	$ 283,482	$ (290,958)
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided by Operating Activities:			
Impairment of Oil and Gas Producing Properties	—	—	948,307
Depreciation, Depletion and Amortization	240,961	224,195	249,417
Deferred Income Taxes	(18,153)	117,975	(246,794)
Excess Tax Benefits Associated with Stock-Based Compensation Awards	—	—	(1,868)
Stock-Based Compensation	15,762	12,262	5,755
Other	16,133	16,476	12,620
Change in:			
Hedging Collateral Deposits	(1,700)	(257)	9,640
Receivables and Unbilled Revenue	(30,882)	(3,380)	(6,408)
Gas Stored Underground and Materials and Supplies	(4,021)	(1,417)	(3,532)
Unrecovered Purchased Gas Costs	419	(2,183)	(2,440)
Other Current Assets	(16,519)	7,849	3,179
Accounts Payable	17,962	17,192	(40,664)
Amounts Payable to Customers	3,394	(19,537)	(37,241)
Customer Advances	(2,092)	939	(1,474)
Customer Security Deposits	5,331	4,353	(471)
Other Accruals and Current Liabilities	3,865	27,004	3,453
Other Assets	(9,556)	(2,885)	1,941
Other Liabilities	1,178	2,183	(13,483)
Net Cash Provided by Operating Activities	613,603	684,251	588,979
Investing Activities			
Capital Expenditures	(584,004)	(450,335)	(581,576)
Net Proceeds from Sale of Oil and Gas Producing Properties	55,506	26,554	137,316
Other	(389)	1,216	(9,236)
Net Cash Used in Investing Activities	(528,887)	(422,565)	(453,496)
Financing Activities			
Excess Tax Benefits Associated with Stock-Based Compensation Awards	—	—	1,868
Net Proceeds from Issuance of Long-Term Debt	295,020	295,151	—
Reduction of Long-Term Debt	(566,512)	—	—
Net Proceeds from Issuance of Common Stock	4,110	7,784	13,849
Dividends Paid on Common Stock	(143,258)	(139,063)	(134,824)
Net Cash Provided by (Used in) Financing Activities	(410,640)	163,872	(119,107)
Net Increase (Decrease) in Cash and Temporary Cash Investments	(325,924)	425,558	16,376
Cash and Temporary Cash Investments At Beginning of Year	555,530	129,972	113,596
Cash and Temporary Cash Investments At End of Year	$ 229,606	$ 555,530	$ 129,972
Supplemental Disclosure of Cash Flow Information			
Cash Paid For:			
Interest	$ 126,079	$ 116,894	$ 119,563
Income Taxes	$ 31,771	$ 34,826	$ 34,240
Non-Cash Investing Activities:			
Non-Cash Capital Expenditures	$ 88,813	$ 72,216	$ 60,434
Receivable from Sale of Oil and Gas Producing Properties	$ —	$ —	$ 19,543

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note A — 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.

Regulation

The Company is subject to regulation by certain state and federal authorities. The Company has accounting policies which conform to GAAP, as applied to regulated enterprises, and are in accordance with the accounting requirements and ratemaking practices of the regulatory authorities. Reference is made to Note C — Regulatory Matters for further discussion.

Revenue Recognition

The Company's Exploration and Production segment records revenue based on entitlement, which means that revenue is recorded based on the actual amount of gas or oil that is delivered to a pipeline and the Company's ownership interest in the producing well. If a production imbalance occurs between what was supposed to be delivered to a pipeline and what was actually produced and delivered, the Company accrues the difference as an imbalance.

The Company's Pipeline and Storage segment records revenue for natural gas transportation and storage services. Revenue from reservation charges on firm contracted capacity is recognized through equal monthly charges over the contract period regardless of the amount of gas that is transported or stored. Commodity charges on firm contracted capacity and interruptible contracts are recognized as revenue when physical deliveries of natural gas are made at the agreed upon delivery point or when gas is injected or withdrawn from the storage field. The point of delivery into the pipeline or injection or withdrawal from storage is the point at which ownership and risk of loss transfers to the buyer of such transportation and storage services.

In the Company's Gathering segment, revenue is recorded at the point at which gathered volumes are delivered into interstate pipelines.

The Company's Utility segment records revenue for gas sales and transportation in the period that gas is delivered to customers. This includes the recording of receivables for gas delivered but not yet billed to customers based on the Company's estimate of the amount of gas delivered between the last meter reading date and the end of the accounting period. Such receivables are a component of Unbilled Revenue on the Consolidated Balance Sheets.

The Company's Energy Marketing segment records revenue for gas sales in the period that gas is delivered to customers. This includes the recording of receivables for gas delivered but not yet billed to customers based on the Company's estimate of the amount of gas delivered between the last meter reading date and the end of the accounting period. Such receivables are a component of Unbilled Revenue on the Consolidated Balance Sheets.

Allowance for Uncollectible Accounts

The allowance for uncollectible accounts is the Company's best estimate of the amount of probable credit losses in the existing accounts receivable. The allowance is determined based on historical experience, the age and other specific information about customer accounts. Account balances are charged off against the allowance twelve months after the account is final billed or when it is anticipated that the receivable will not be recovered.

Regulatory Mechanisms

The Company's rate schedules in the Utility segment contain clauses that permit adjustment of revenues to reflect price changes from the cost of purchased gas included in base rates. Differences between amounts currently recoverable and actual adjustment clause revenues, as well as other price changes and pipeline and storage company refunds not yet includable in adjustment clause rates, are deferred and accounted for as either unrecovered purchased gas costs or amounts payable to customers. Such amounts are generally recovered from (or passed back to) customers during the following fiscal year.

Estimated refund liabilities to ratepayers represent management's current estimate of such refunds. Reference is made to Note C — Regulatory Matters for further discussion.

The impact of weather on revenues in the Utility segment's New York rate jurisdiction is tempered by a WNC, which covers the eight-month period from October through May. The WNC is designed to adjust the rates of retail customers to reflect the impact of deviations from normal weather. Weather that is warmer than normal results in a surcharge being added to customers' current bills, while weather that is colder than normal results in a refund being credited to customers' current bills. Since the Utility segment's Pennsylvania rate jurisdiction does not have a WNC, weather variations have a direct impact on the Pennsylvania rate jurisdiction's revenues.

The impact of weather normalized usage per customer account in the Utility segment's New York rate jurisdiction is tempered by a revenue decoupling mechanism. The effect of the revenue decoupling mechanism is to render the Company financially indifferent to throughput decreases resulting from conservation. Weather normalized usage per account that exceeds the average weather normalized usage per customer account results in a refund being credited to customers' bills. Weather normalized usage per account that is below the average weather normalized usage per account results in a surcharge being added to customers' bills. The surcharge or credit is calculated over a twelve-month period ending December 31st, and applied to customer bills annually, beginning March 1st.

In the Pipeline and Storage segment, the allowed rates that Supply Corporation and Empire bill their customers are based on a straight fixed-variable rate design, which allows recovery of all fixed costs, including return on equity and income taxes, through fixed monthly reservation charges. Because of this rate design, changes in throughput due to weather variations do not have a significant impact on the revenues of Supply Corporation or Empire.

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. For further discussion of capitalized costs, refer to Note L — Supplementary Information for Oil and Gas Producing Activities.

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 September 30, 2018, the ceiling exceeded the book value of the oil and gas properties by $569.1 million. In adjusting estimated future net cash flows for hedging under the ceiling test, estimated future net cash flows were decreased by $25.1 million at September 30, 2018 and were increased by $30.5 million and $215.3 million at September 30, 2017 and 2016, respectively.

The Company entered into a purchase and sale agreement to sell its oil and gas properties in the Sespe Field area of Ventura County, California in October 2017 for $43.0 million. The Company completed the sale on May 1, 2018, effective as of October 1, 2017, receiving net proceeds of $38.2 million (included in Net Proceeds from Sale of Oil and Gas Producing Properties on the Consolidated Statement of Cash Flows for the year ended September 30, 2018). The net proceeds received by the Company were adjusted for production revenue and production expenses retained by the Company between the effective date of the sale and the closing date, resulting in lower proceeds from sale at the closing date. The divestiture of the Company's oil and gas properties in the Sespe Field reflects continuing efforts to focus West Coast development activities in the San Joaquin basin, particularly at the Midway Sunset field in Kern County, California. Under the full cost method of accounting for oil and natural gas properties, the sale proceeds were accounted for as a reduction of capitalized costs. Since the disposition did not significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to the cost center, the Company did not record any gain or loss from this sale.

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 jointly participate in a program to develop up to 75 Marcellus wells, with Seneca serving as program operator. IOG holds an 80% working interest in all of the joint development wells. In total, IOG has funded $305.5 million as of September 30. 2018 for its 80% working interest in the 75 joint development wells, which includes $181.2 million of cash ($137.3 million in fiscal 2016, $26.6 million in fiscal 2017 and $17.3 million in fiscal 2018) included in Net Proceeds from Sale of Oil and Gas Producing Properties on the Consolidated Statements of Cash Flows for fiscal 2016, fiscal 2017 and for fiscal 2018, respectively. 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. 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 48 of the joint development wells. Effective June 1, 2018, actual production for 8 of the joint development wells did not meet production targets, which resulted in an adjustment to Seneca's royalty interest from 7.5% to 4.98% with no change to the 20% working interest (23.98% net revenue interest). 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.

The principal assets of the Utility and Pipeline and Storage segments, consisting primarily of gas plant in service, are recorded at the historical cost when originally devoted to service.

Maintenance and repairs of property and replacements of minor items of property are charged directly to maintenance expense. The original cost of the regulated subsidiaries' property, plant and equipment retired, and the cost of removal less salvage, are charged to accumulated depreciation.

Depreciation, Depletion and Amortization

For oil and gas properties, depreciation, depletion and amortization is computed based on quantities produced in relation to proved reserves using the units of production method. The cost of unproved oil and gas properties is excluded from this computation. In the All Other category, for timber properties, depletion, determined on a property by property basis, is charged to operations based on the actual amount of timber cut in relation to the total amount of recoverable timber. For all other property, plant and equipment, depreciation and amortization is computed using the straight-line method in amounts sufficient to recover costs over the estimated service lives of property in service. The following is a summary of depreciable plant by segment:

	As of September 30	
	2018	2017
	(Thousands)	
Exploration and Production	$ 5,222,037	$ 4,925,409
Pipeline and Storage	2,110,714	2,002,736
Gathering	527,188	484,768
Utility	2,104,437	2,045,074
Energy Marketing	3,604	3,564
All Other and Corporate	108,691	109,128
	$ 10,076,671	$ 9,570,679

Average depreciation, depletion and amortization rates are as follows:

	Year Ended September 30		
	2018	2017	2016
Exploration and Production, per Mcfe(1)	$ 0.70	$ 0.65	$ 0.87
Pipeline and Storage	2.2%	2.2%	2.4%
Gathering	3.4%	3.4%	4.0%
Utility	2.8%	2.8%	2.7%
Energy Marketing	7.7%	7.9%	7.9%
All Other and Corporate	2.2%	1.3%	1.8%

(1) Amounts include depletion of oil and gas producing properties as well as depreciation of fixed assets. As disclosed in Note L — Supplementary Information for Oil and Gas Producing Activities, depletion of oil and gas producing properties amounted to $0.67, $0.63 and $0.85 per Mcfe of production in 2018, 2017 and 2016, respectively.

Goodwill

The Company has recognized goodwill of $5.5 million as of September 30, 2018 and 2017 on its Consolidated Balance Sheets related to the Company's acquisition of Empire in 2003. The Company accounts for goodwill in accordance with the current authoritative guidance, which requires the Company to test goodwill for impairment annually. At September 30, 2018, 2017 and 2016, the fair value of Empire was greater than its book value. As such, the goodwill was not considered impaired at those dates. Going back to the origination of the goodwill in 2003, the Company has never recorded an impairment of its goodwill balance.

Financial Instruments

Unrealized gains or losses from the Company's investments in an equity mutual fund, a fixed income mutual fund and the stock of an insurance company (securities available for sale) are recorded as a component of accumulated other comprehensive income (loss). Reference is made to Note G — Financial Instruments for further discussion.

The Company uses a variety of derivative financial instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and crude oil and to manage a portion of the risk of currency fluctuations associated with transportation costs denominated in Canadian currency. These instruments include price swap agreements and futures contracts. The Company accounts for these instruments as either cash flow hedges or fair value hedges. In both cases, the fair value of the instrument is recognized on the Consolidated Balance Sheets as either an asset or a liability labeled Fair Value of Derivative Financial Instruments. Reference is made to Note F — Fair Value Measurements for further discussion concerning the fair value of derivative financial instruments.

For effective cash flow hedges, the offset to the asset or liability that is recorded is a gain or loss recorded in accumulated other comprehensive income (loss) on the Consolidated Balance Sheets. The gain or loss recorded in accumulated other comprehensive income (loss) remains there until the hedged transaction occurs, at which point the gains or losses are reclassified to operating revenues, purchased gas expense or operation and maintenance expense on the Consolidated Statements of Income. Reference is made to Note G — Financial Instruments for further discussion concerning cash flow hedges.

For fair value hedges, the offset to the asset or liability that is recorded is a gain or loss recorded to operating revenues or purchased gas expense on the Consolidated Statements of Income. However, in the case of fair value hedges, the Company also records an asset or liability on the Consolidated Balance Sheets representing the change in fair value of the asset or firm commitment that is being hedged (see Other Current Assets section in this footnote). The offset to this asset or liability is a gain or loss recorded to operating revenues or purchased gas expense on the Consolidated Statements of Income as well. If the fair value hedge is effective, the gain or loss from the derivative financial instrument is offset by the gain or loss that arises from the change in fair value of the asset or firm commitment that is being hedged. Reference is made to Note G — Financial Instruments for further discussion concerning fair value hedges.

Accumulated Other Comprehensive Income (Loss)

The components of Accumulated Other Comprehensive Income (Loss) and changes for the year ended September 30, 2018, 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
Year Ended September 30, 2018				
Balance at October 1, 2017	$ 20,801	$ 7,562	$ (58,486)	$ (30,123)
Other Comprehensive Gains and Losses Before Reclassifications	(51,556)	147	4,643	(46,766)
Amounts Reclassified From Other Comprehensive Loss	2,144	(272)	7,267	9,139
Balance at September 30, 2018	$ (28,611)	$ 7,437	$ (46,576)	$ (67,750)
Year Ended September 30, 2017				
Balance at October 1, 2016	$ 64,782	$ 6,054	$ (76,476)	$ (5,640)
Other Comprehensive Gains and Losses Before Reclassifications	3,338	2,503	9,486	15,327
Amounts Reclassified From Other Comprehensive Loss	(47,319)	(995)	8,504	(39,810)
Balance at September 30, 2017	$ 20,801	$ 7,562	$ (58,486)	$ (30,123)

The amounts included in accumulated other comprehensive income (loss) related to the funded status of the Company's pension and other post-retirement benefit plans consist of prior service costs and accumulated losses. The total amount for prior service cost was $1.0 million and $1.2 million at September 30, 2018 and 2017, respectively. The total amount for accumulated losses was $45.6 million and $57.3 million at September 30, 2018 and 2017, respectively.

Reclassifications Out of Accumulated Other Comprehensive Income (Loss)

The details about the reclassification adjustments out of accumulated other comprehensive loss for the year ended September 30, 2018 are as follows (amounts in parentheses indicate debits to the income statement) (in thousands):

Details About Accumulated Other Comprehensive Income (Loss) Components	Amount of Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) for the Year Ended September 30,		Affected Line Item in the Statement Where Net Income (Loss) is Presented
	2018	2017	
Gains (Losses) on Derivative Financial Instrument Cash Flow Hedges:			
Commodity Contracts	$423	$83,983	Operating Revenues
Commodity Contracts	952	(1,921)	Purchased Gas
Foreign Currency Contracts	(2,564)	(457)	Operation and Maintenance Expense
Gains (Losses) on Securities Available for Sale	430	1,575	Other Income
Amortization of Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans:			
Prior Service Credit	(258)	(288)	(1)
Net Actuarial Loss	(9,446)	(13,145)	(1)
	(10,463)	69,747	Total Before Income Tax
	1,324	(29,937)	Income Tax Expense
	($9,139)	$39,810	Net of Tax

(1) These accumulated other comprehensive income (loss) components are included in the computation of net periodic benefit cost. Refer to Note H — Retirement Plan and Other Post-Retirement Benefits for additional details.

Gas Stored Underground

In the Utility segment, gas stored underground in the amount of $27.6 million is carried at lower of cost or net realizable value, on a LIFO method. Based upon the average price of spot market gas purchased in September 2018, including transportation costs, the current cost of replacing this inventory of gas stored underground exceeded the amount stated on a LIFO basis by approximately $40.2 million at September 30, 2018. All other gas stored underground, which is in the Energy Marketing segment, is carried at an average cost method, subject to lower of cost or net realizable value adjustments.

Unamortized Debt Expense

Costs associated with the reacquisition of debt related to rate-regulated subsidiaries are deferred and amortized over the remaining life of the issue or the life of the replacement debt in order to match regulatory treatment. At September 30, 2018, the remaining weighted average amortization period for such costs was approximately 8 years.

Income Taxes

The Company and its subsidiaries file a consolidated federal income tax return. State tax returns are filed on a combined or separate basis depending on the applicable laws in the jurisdictions where tax returns are filed.

The Company follows the asset and liability approach in accounting for income taxes, which requires the recognition of deferred income taxes for the expected future tax consequences of net operating losses, credits and temporary differences between the financial statement carrying amounts and the tax basis of assets and liabilities. A valuation allowance is provided on deferred tax assets if it is determined, within each taxing jurisdiction, that it is more likely than not that the asset will not be realized.

The Company reports a liability or a reduction of deferred tax assets for unrecognized tax benefits resulting from uncertain tax positions taken or expected to be taken in a tax return. When applicable, the Company recognizes interest relating to uncertain tax positions in Other Interest Expense and penalties in Other Income.

Consolidated Statement of Cash Flows

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

Hedging Collateral Deposits

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

Other Current Assets

The components of the Company's Other Current Assets are as follows:

	Year Ended September 30	
	2018	2017
	(Thousands)	
Prepayments	$ 11,126	$ 10,927
Prepaid Property and Other Taxes	14,088	13,974
Federal Income Taxes Receivable	22,457	—
State Income Taxes Receivable	8,822	9,689
Fair Values of Firm Commitments	1,739	1,031
Regulatory Assets	9,792	15,884
	$ 68,024	$ 51,505

Other Accruals and Current Liabilities

The components of the Company's Other Accruals and Current Liabilities are as follows:

	Year Ended September 30	
	2018	2017
	(Thousands)	
Accrued Capital Expenditures	$ 38,354	$ 37,382
Regulatory Liabilities	57,425	34,059
Federal Income Taxes Payable	—	1,775
Other	36,914	38,673
	$ 132,693	$ 111,889

Customer Advances

The Company's Utility and Energy Marketing segments have balanced billing programs whereby customers pay their estimated annual usage in equal installments over a twelve-month period. Monthly payments under the balanced billing programs are typically higher than current month usage during the summer months. During the winter months, monthly payments under the balanced billing programs are typically lower than current month usage. At September 30, 2018 and 2017, customers in the balanced billing programs had advanced excess funds of $13.6 million and $15.7 million, respectively.

Customer Security Deposits

The Company, in its Utility, Pipeline and Storage, and Energy Marketing segments, often times requires security deposits from marketers, producers, pipeline companies, and commercial and industrial customers before providing services to such customers. At September 30, 2018 and 2017, the Company had received customer security deposits amounting to $25.7 million and $20.4 million, respectively.

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 had outstanding were stock options, SARs, restricted stock units and performance shares. For the years ended September 30, 2018 and 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 317,899 securities and 157,649 securities excluded as being antidilutive for the years ended September 30, 2018 and 2017, respectively. As the Company recognized a net loss for the year ended September 30, 2016, the aforementioned potentially dilutive securities, amounting to 431,408 securities, were not recognized in the diluted earnings per share calculation for 2016.

Stock-Based Compensation

The Company has various stock award plans which provide or provided for the issuance of one or more of the following to key employees: SARs, incentive stock options, nonqualified stock options, restricted stock, restricted stock units, performance units or performance shares. The Company follows authoritative guidance which requires the measurement and recognition of compensation cost at fair value for all share-based payments. SARs and stock options under all plans have exercise prices equal to the average market price of Company common stock on the date of grant, and generally no SAR or stock option is exercisable less than one year or more than ten years after the date of each grant. The Company has chosen the Black-Scholes-Merton closed form model to calculate the compensation expense associated with SARs and stock options. For all Company stock awards, forfeitures are recognized as they occur.

Restricted stock is subject to restrictions on vesting and transferability. Restricted stock awards entitle the participants to full dividend and voting rights. The market value of restricted stock on the date of the award is recorded as compensation expense over the vesting period. Certificates for shares of restricted stock awarded under the Company's stock award plans are held by the Company during the periods in which the restrictions on vesting are effective. Restrictions on restricted stock awards generally lapse ratably over a period of not more than ten years after the date of each grant. Restricted stock units also are subject to restrictions on vesting and transferability. Restricted stock units, both performance and non-performance based, 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. The performance based and non-performance based restricted stock units do not entitle the participants to dividend and voting rights. The accounting for performance based and 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 (represented by the market value of Company common stock on the date of the award) must be reduced by the present value of forgone dividends over the vesting term of the award. The fair value of restricted stock units on the date of award is recorded as compensation expense over the vesting period.

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. For performance shares based on a return on capital goal, the fair value at the date of grant of the performance shares is determined by multiplying the expected number of performance shares to be issued by the market value of Company common stock on the date of grant reduced by the present value of forgone dividends. For performance shares based on a total shareholder return goal, the Company uses the Monte Carlo simulation technique to estimate the fair value price at the date of grant.

Refer to Note E — Capitalization and Short-Term Borrowings under the heading "Stock Award Plans" for additional disclosures related to stock-based compensation awards for all plans.

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 Company adopted this authoritative guidance effective October 1, 2018 using the modified retrospective method of adoption. Detailed review of the impact of the guidance on each of the Company's revenue streams was completed. Based on that review, the Company did not identify any changes to net income, cash flows or the timing of revenue recognition. The Company will be enhancing its financial statement disclosures to comply with the new authoritative guidance for the quarter ending December 31, 2018.

In January 2016, the FASB issued authoritative guidance regarding the recognition and measurement of financial assets and liabilities. The authoritative guidance primarily affects the accounting for equity investments and the presentation and disclosure requirements for financial instruments. All equity investments in unconsolidated entities will be measured at fair value through earnings rather than through accumulated other comprehensive income. The Company adopted this authoritative guidance effective October 1, 2018 and will be, as called for by the modified retrospective method of adoption, recording a cumulative effect adjustment for the quarter ended December 31, 2018 to increase retained earnings by $7.4 million and decrease accumulated other comprehensive income by the same amount.

In February 2016, the FASB issued authoritative guidance, which has subsequently been amended, 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.

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 is eligible to be capitalized as part of the cost of inventory or property, plant and equipment while the other components of net periodic pension cost and net periodic postretirement benefit cost are generally not eligible for capitalization, unless allowed by a regulator. The new guidance will be effective as of the Company's first quarter of fiscal 2019. Refer to Note H — Retirement Plan and Other Post-Retirement Benefits for the components of the Company's net periodic pension cost and net periodic postretirement benefit cost.

In February 2018, the FASB issued authoritative guidance that allows an entity to elect a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the 2017 Tax Reform Act and requires certain disclosures about stranded tax effects. The new guidance will be effective as of the Company's first quarter of fiscal 2020, with early adoption permitted. The Company anticipates early adoption and is currently awaiting regulatory approval of the reclassification to retained earnings from the FERC for the Company's Pipeline and Storage segment.

Note B — Asset Retirement Obligations

The Company accounts for asset retirement obligations in accordance with the authoritative guidance that requires entities to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. An asset retirement obligation is defined as a legal obligation associated with the retirement of a tangible long-lived asset in which the timing and/or method of settlement may or may not be conditional on a future event that may or may not be within the control of the Company. When the liability is initially recorded, the entity capitalizes the estimated cost of retiring the asset as part of the carrying amount of the related long-lived asset. Over time, the liability is adjusted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. The Company estimates the fair value of its asset retirement obligations based on the discounting of expected cash flows using various estimates, assumptions and judgments regarding certain factors such as the existence of a legal obligation for an asset retirement obligation; estimated amounts and timing of settlements; the credit-adjusted risk-free rate to be used; and inflation rates. Asset retirement obligations incurred in the current period were Level 3 fair value measurements as the inputs used to measure the fair value are unobservable.

The Company has recorded an asset retirement obligation representing plugging and abandonment costs associated with the Exploration and Production segment's crude oil and natural gas wells and has capitalized such costs in property, plant and equipment (i.e. the full cost pool).

In addition to the asset retirement obligation recorded in the Exploration and Production segment, the Company has recorded future asset retirement obligations associated with the plugging and abandonment of natural gas storage wells in the Pipeline and Storage segment and the removal of asbestos and asbestos-containing material in various facilities in the Utility and Pipeline and Storage segments. The Company has also recorded asset retirement obligations for certain costs connected with the retirement of the distribution mains, services and other components of the pipeline system in the Utility segment, the transmission mains and other components in the pipeline system in the Pipeline and Storage segment, and the gathering lines and other components in the Gathering segment. The retirement costs within the distribution, transmission and gathering systems are primarily for the capping and purging of pipe, which are generally abandoned in place when retired, as well as for the clean-up of PCB contamination associated with the removal of certain pipe.

On June 30, 2016, Seneca sold the majority of its Upper Devonian wells in Pennsylvania. While the proceeds from the sale were not significant, it did result in a $58.4 million reduction of its Asset Retirement Obligation at September 30, 2016, which is reflected in Liabilities Settled in the table below. The following is a reconciliation of the change in the Company's asset retirement obligations:

	Year Ended September 30		
	2018	2017	2016
		(Thousands)	
Balance at Beginning of Year	$ 106,395	$ 112,330	$ 156,805
Liabilities Incurred	5,597	2,963	2,719
Revisions of Estimates	(419)	(10,578)	16,721
Liabilities Settled	(12,858)	(4,967)	(72,215)
Accretion Expense	9,520	6,647	8,300
Balance at End of Year	$ 108,235	$ 106,395	$ 112,330

Note C — Regulatory Matters

Regulatory Assets and Liabilities

The Company has recorded the following regulatory assets and liabilities:

	At September 30	
	2018	2017
	(Thousands)	
Regulatory Assets(1):		
Pension Costs(2) (Note H)	$ 62,703	$ 125,175
Post-Retirement Benefit Costs(2) (Note H)	11,160	13,886
Recoverable Future Taxes (Note D)	115,460	181,363
Environmental Site Remediation Costs(2) (Note I)	20,308	19,665
Asset Retirement Obligations(2) (Note B)	15,495	12,764
Unamortized Debt Expense (Note A)	15,975	1,159
Other(3)	13,044	18,827
Total Regulatory Assets	254,145	372,839
Less: Amounts Included in Other Current Assets	(9,792)	(15,884)
Total Long-Term Regulatory Assets	$ 244,353	$ 356,955

	At September 30 2018	At September 30 2017
	(Thousands)	
Regulatory Liabilities:		
Cost of Removal Regulatory Liability	$ 212,311	$ 204,630
Taxes Refundable to Customers (Note D)	370,628	95,739
Post-Retirement Benefit Costs (Note H)	134,387	102,891
Amounts Payable to Customers (See Regulatory Mechanisms in Note A)	3,394	—
Other(4)	69,781	44,884
Total Regulatory Liabilities	790,501	448,144
Less: Amounts included in Current and Accrued Liabilities	(60,819)	(34,059)
Total Long-Term Regulatory Liabilities	$ 729,682	$ 414,085

(1) The Company recovers the cost of its regulatory assets but generally does not earn a return on them. There are a few exceptions to this rule. For example, the Company does earn a return on Unrecovered Purchased Gas Costs and, in the New York jurisdiction of its Utility segment, earns a return, within certain parameters, on the excess of cumulative funding to the pension plan over the cumulative amount collected in rates.

(2) Included in Other Regulatory Assets on the Consolidated Balance Sheets.

(3) $9,792 and $15,884 are included in Other Current Assets on the Consolidated Balance Sheets at September 30, 2018 and 2017, respectively, since such amounts are expected to be recovered from ratepayers in the next 12 months. $3,252 and $2,943 are included in Other Regulatory Assets on the Consolidated Balance Sheets at September 30, 2018 and 2017, respectively.

(4) $57,425 and $34,059 are included in Other Accruals and Current Liabilities on the Consolidated Balance Sheets at September 30, 2018 and 2017, respectively, since such amounts are expected to be recovered from ratepayers in the next 12 months. $12,356 and $10,825 are included in Other Regulatory Liabilities on the Consolidated Balance Sheets at September 30, 2018 and 2017, respectively.

If for any reason the Company ceases to meet the criteria for application of regulatory accounting treatment for all or part of its operations, the regulatory assets and liabilities related to those portions ceasing to meet such criteria would be eliminated from the Consolidated Balance Sheets and included in income of the period in which the discontinuance of regulatory accounting treatment occurs.

Cost of Removal Regulatory Liability

In the Company's Utility and Pipeline and Storage segments, costs of removing assets (i.e. asset retirement costs) are collected from customers through depreciation expense. These amounts are not a legal retirement obligation as discussed in Note B — Asset Retirement Obligations. Rather, they are classified as a regulatory liability in recognition of the fact that the Company has collected dollars from the customer that will be used in the future to fund asset retirement costs.

New York Jurisdiction

Distribution Corporation's current delivery rates in its New York jurisdiction were approved by the NYPSC in an order issued on April 20, 2017 with rates becoming effective May 1, 2017. The order provided for a return on equity of 8.7%.

On August 9, 2018, in response to the enactment of the 2017 Tax Reform Act, the NYPSC issued an Order Determining Rate Treatment of Tax Changes directing utilities to make compliance filings effective October 1, 2018 to begin providing sur-credits to customers reflecting tax savings associated with the 2017 Tax Reform Act.

In compliance with that order, Distribution Corporation filed the necessary tariff amendments to implement the sur-credit effective October 1, 2018. At September 30, 2018, a refund provision of $9.1 million associated with the impact of the 2017 Tax Reform Act in the New York jurisdiction was included in Other Accruals and Current Liabilities on the Consolidated Balance Sheet. Refer to Note D — Income Taxes for further discussion of the 2017 Tax Reform Act.

Pennsylvania Jurisdiction

Distribution Corporation's Pennsylvania jurisdiction delivery rates are being charged to customers in accordance with a rate settlement approved by the PaPUC. The rate settlement does not specify any requirement to file a future rate case.

In response to the issuance of the 2017 Tax Reform Act, the PaPUC issued an Order to Distribution Corporation on May 17, 2018, requiring that Distribution Corporation file a tariff supplement establishing temporary rates to implement refunds of 2.2% on customer rates beginning July 1, 2018. In compliance with the May 17, 2018 PaPUC Order, Distribution Corporation filed a subsequent tariff supplement adjusting the negative surcharge in connection with the start of its new fiscal year, with the new rates effective October 1, 2018 and subject to reconciliation. At September 30, 2018, a refund provision of $3.4 million associated with the impact of the 2017 Tax Reform Act in the Pennsylvania jurisdiction was included in Other Accruals and Current Liabilities on the Consolidated Balance Sheet. Refer to Note D — Income Taxes for further discussion of the 2017 Tax Reform Act.

FERC Jurisdiction

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. The FERC's July 2018 Final Rule in RM18-11-000, et. al, (Order No. 849) requires pipelines to file a new form isolating the tax impact to each pipeline and also to make an election regarding the action the pipelines will take to address the lower tax rates, one of which is filing a Section 4 rate proceeding. Supply Corporation is required to address the Order by December 6, 2018. At this point, the Company cannot predict the outcome of any action taken pursuant to the Order. Refer to Note D — Income Taxes for further discussion of the 2017 Tax Reform Act.

Empire filed a Section 4 rate case on June 29, 2018, proposing rate increases to be effective August 1, 2018. The proposed rates reflect an annual cost of service of $71.5 million, a rate base of $246.8 million and a proposed return on equity of 14%. The FERC has accepted the filed rates and suspended the effective date of the increases until January 1, 2019, when the increased rates will be made effective, subject to refund. Since Empire has filed a rate case, it is not obligated to make a filing under RM18-11-000.

Note D — Income Taxes

On December 22, 2017, federal tax legislation referred to as the "Tax Cuts and Jobs Act" (the 2017 Tax Reform Act) was enacted. The 2017 Tax Reform Act significantly changed the taxation of business entities and includes a 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. The changes had a material impact on the financial statements in the year ended September 30, 2018. The Company's deferred income taxes were remeasured based upon the new tax rates. For the non-rate regulated activities through the year ended September 30, 2018, the change in beginning of the year deferred income taxes of $103.5 million (which includes the potential sequestration of the refunds of the AMT credit carryovers as described below) was recorded as a reduction to income tax expense. For the Company's rate regulated activities, the reduction in 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. For further discussion, refer to Note C — Regulatory Matters.

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, if not utilized to reduce tax, beginning in fiscal 2019. As of September 30, 2018, the Company had $84.2 million of AMT credit carryovers that are expected to be utilized or refunded between fiscal 2019 and fiscal 2022. These amounts are recorded in Deferred Income Taxes and will be reclassified to a receivable when the amounts are expected to be realized in cash. During the year ended September 30, 2018, the Company recorded a $5.0 million estimate for the potential sequestration of AMT credit refunds.

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. 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 September 30, 2018 financial statements. The final determination of the impact of the income tax effects of these items will require further interpretation of the 2017 Tax Reform Act from yet to be issued U.S. Treasury regulations, state income tax guidance, federal/state regulatory guidance, and possible technical corrections, which, if issued, the Company expects to finalize within SAB 118's measurement period (quarter ended December 31, 2018). Any subsequent guidance will be accounted for in the period issued.

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

	Year Ended September 30		
	2018	2017	2016
		(Thousands)	
Current Income Taxes —			
Federal	$ 2,025	$ 32,034	$ (6,658)
State	8,634	10,673	20,903
Deferred Income Taxes —			
Federal	(38,927)	103,046	(164,818)
State	20,774	14,929	(81,976)
	(7,494)	160,682	(232,549)
Deferred Investment Tax Credit	(105)	(173)	(348)
Total Income Taxes	$ (7,599)	$ 160,509	$ (232,897)
Presented as Follows:			
Other Income	$ (105)	$ (173)	$ (348)
Income Tax Expense (Benefit)	(7,494)	160,682	(232,549)
Total Income Taxes	$ (7,599)	$ 160,509	$ (232,897)

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

	Year Ended September 30		
	2018	2017	2016
		(Thousands)	
U.S. Income (Loss) Before Income Taxes	$ 383,922	$ 443,991	$ (523,855)
Income Tax Expense (Benefit), Computed at U.S. Federal Statutory Rate(1)	$ 94,061	$ 155,397	$ (183,349)
Impact of 2017 Tax Reform Act(2)	(112,598)	—	—
State Income Taxes (Benefit)(3)	22,203	16,641	(39,697)
Federal Tax Credits	(6,576)	(6,679)	(3,262)
Miscellaneous	(4,689)	(4,850)	(6,589)
Total Income Taxes	$ (7,599)	$ 160,509	$ (232,897)

(1) For fiscal 2018, represents the blended rate of 24.5%. Calculated as 35% for the first quarter of the fiscal year and 21% for the remaining three quarters.
(2) Represents the remeasurement of deferred income taxes as a result of the lower U.S. corporate income tax rate including a $5.0 million estimate for the potential sequestration of AMT credit refunds and the benefit of $9.1 million as a result of the blended tax rate described above.
(3) The state income taxes (benefit) shown above includes income tax benefits related to state enhanced oil recovery tax credits and adjustments to the estimated state effective tax rates utilized in the calculation of deferred income taxes.

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

	At September 30	
	2018	2017
	(Thousands)	
Deferred Tax Liabilities:		
Property, Plant and Equipment	$ 770,794	$ 1,141,432
Pension and Other Post-Retirement Benefit Costs	39,541	79,516
Other	49,734	77,046
Total Deferred Tax Liabilities	860,069	1,297,994
Deferred Tax Assets:		
Pension and Other Post-Retirement Benefit Costs	(62,969)	(123,532)
Tax Loss and Credit Carryforwards	(214,128)	(200,344)
Other	(75,286)	(82,831)
Total Gross Deferred Tax Assets	(352,383)	(406,707)
Valuation Allowance	5,000	—
Total Deferred Tax Assets	(347,383)	(406,707)
Total Net Deferred Income Taxes	$ 512,686	$ 891,287

As explained in Note A — Summary of Significant Accounting Policies under the heading "New Authoritative Accounting and Financial Reporting Guidance," the Company adopted authoritative guidance issued by the FASB simplifying several aspects of the accounting for stock-based compensation effective as of October 1, 2016. Under this guidance, the Company recognizes excess tax benefits as incurred. The Company recognized $31.9 million, that arose directly from excess tax benefits related to stock-based compensation in prior periods, as a cumulative effect adjustment increasing retained earnings at October 1, 2016.

Regulatory liabilities representing the reduction of previously recorded deferred income taxes associated with rate-regulated activities that are expected to be refundable to customers amounted to $370.6 million and $95.7 million at September 30, 2018 and 2017, respectively. Also, regulatory assets representing future amounts collectible from customers, corresponding to additional deferred income taxes not previously recorded because of ratemaking practices, amounted to $115.5 million and $181.4 million at September 30, 2018 and 2017, respectively.

The following is a reconciliation of the change in unrecognized tax benefits:

	Year Ended September 30		
	2018	2017	2016
		(Thousands)	
Balance at Beginning of Year	$ 1,251	$ 396	$ 5,085
Additions for Tax Positions of Prior Years	—	1,251	396
Reductions for Tax Positions of Prior Years	(788)	(396)	(1,314)
Reductions Related to Settlements with Taxing Authorities	(463)	—	(3,771)
Balance at End of Year	$ —	$ 1,251	$ 396

The IRS is currently conducting examinations of the Company for fiscal 2018 in accordance with the Compliance Assurance Process (“CAP”). The CAP audit employs a real time review of the Company’s books and tax records by the IRS that is intended to permit issue resolution prior to the filing of the tax return. The federal statute of limitations remains open for fiscal 2009, fiscal 2015 and later years. During fiscal 2009, preliminary consent was received from the IRS National Office approving the Company’s application to change its tax method of accounting for certain capitalized costs relating to its utility property, subject to the final guidance. The Company is awaiting the issuance of IRS guidance addressing the issue for natural gas utilities.

The Company is also subject to various routine state income tax examinations. The Company’s principal subsidiaries operate mainly in four states which have statutes of limitations that generally expire between three to four years from the date of filing of the income tax return.

As of September 30, 2018, the Company has the following carryforwards available:

Jurisdiction	Tax Attribute	Amount (Thousands)		Expires
Federal Pre-Fiscal 2018	Net Operating Loss	$ 191,006	(1)	2029-2037
Federal Post-Fiscal 2017	Net Operating Loss	58,334		Unlimited
Pennsylvania	Net Operating Loss	351,879		2029-2038
California	Net Operating Loss	191,468		2029-2038
Federal	Alternative Minimum Tax Credit	84,185	(2)	Unlimited
California	Alternative Minimum Tax Credit	6,983		Unlimited
Federal	Enhanced Oil Recovery Credit	18,160		2029-2038
California	Enhanced Oil Recovery Credit	7,613		2019-2033
Federal	R&D Tax Credit	5,876		2031-2037
Federal	Charitable Contributions	3,067		2023

(1) Approximately $1.8 million of the federal Net Operating Loss carryforward is subject to certain annual limitations.

(2) The $5.0 million estimate recorded for the potential sequestration of AMT credit refunds is not included in this amount.

Note E — Capitalization and Short-Term Borrowings

Summary of Changes in Common Stock Equity

	Common Stock				
	Shares	Amount	Paid In Capital	Earnings Reinvested in the Business	Accumulated Other Comprehensive Income (Loss)
	(Thousands, except per share amounts)				
Balance at September 30, 2015	84,594	$84,594	$ 744,274	$1,103,200	$ 93,372
Net Income (Loss) Available for Common Stock				(290,958)	
Dividends Declared on Common Stock ($1.60 Per Share)				(135,881)	
Other Comprehensive Loss, Net of Tax					(99,012)
Share-Based Payment Expense(2)			4,843		
Common Stock Issued Under Stock and Benefit Plans(1)	525	525	22,047		
Balance at September 30, 2016	85,119	85,119	771,164	676,361	(5,640)
Net Income Available for Common Stock				283,482	
Dividends Declared on Common Stock ($1.64 Per Share)				(140,090)	
Cumulative Effect of Adoption of Authoritative Guidance for Stock-Based Compensation				31,916	
Other Comprehensive Loss, Net of Tax					(24,483)
Share-Based Payment Expense(2)			10,902		
Common Stock Issued Under Stock and Benefit Plans	424	424	14,580		
Balance at September 30, 2017	85,543	85,543	796,646	851,669	(30,123)
Net Income Available for Common Stock				391,521	
Dividends Declared on Common Stock ($1.68 Per Share)				(144,290)	
Other Comprehensive Loss, Net of Tax					(37,627)
Share-Based Payment Expense(2)			14,235		
Common Stock Issued Under Stock and Benefit Plans	414	414	9,342		
Balance at September 30, 2018	85,957	$85,957	$ 820,223	$1,098,900 (3)	$ (67,750)

(1) Paid in Capital includes tax benefits of $1.9 million for September 30, 2016, related to stock-based compensation.

(2) Paid in Capital includes compensation costs associated with SARs, performance shares and/or restricted stock awards. The expense is included within Net Income Available For Common Stock, net of tax benefits.

(3) The availability of consolidated earnings reinvested in the business for dividends payable in cash is limited under terms of the indentures covering long-term debt. At September 30, 2018, $954.7 million of accumulated earnings was free of such limitations.

Common Stock

The Company has various plans which allow shareholders, employees and others to purchase shares of the Company common stock. The National Fuel Gas Company Direct Stock Purchase and Dividend Reinvestment Plan allows shareholders to reinvest cash dividends and make cash investments in the Company's common stock and provides investors the opportunity to acquire shares of the Company common stock without the payment of any brokerage commissions in connection with such acquisitions. The 401(k) Plans allow employees the opportunity to invest in the Company common stock, in addition to a variety of other investment alternatives. Generally, at the discretion of the Company, shares purchased under these plans are either original issue shares purchased directly from the Company or shares purchased on the open market by an independent agent. During 2018, the Company issued 138,997 original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan and 75,745 original issue shares of common stock for the Company's 401(k) plans.

During 2018, the Company issued 75,971 original issue shares of common stock as a result of SARs exercises, 72,918 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. Holders of stock-based compensation awards will often tender shares of common stock to the Company for payment of applicable withholding taxes. During 2018, 57,065 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.

The Company also has a director stock program under which it issues shares of Company 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 fiscal year. Under this program, the Company issued 28,044 original issue shares of common stock during 2018.

Stock Award Plans

The Company has various stock award plans which provide or provided for the issuance of one or more of the following to key employees: SARs, incentive stock options, nonqualified stock options, restricted stock, restricted stock units, performance units or performance shares.

Stock-based compensation expense for the years ended September 30, 2018, 2017 and 2016 was approximately $14.2 million, $10.8 million and $4.8 million, respectively. Stock-based compensation expense is included in operation and maintenance expense on the Consolidated Statements of Income. The total income tax benefit related to stock-based compensation expense during the years ended September 30, 2018, 2017 and 2016 was approximately $3.4 million, $4.4 million and $1.9 million, respectively. A portion of stock-based compensation expense is subject to capitalization under IRS uniform capitalization rules. Stock-based compensation of $0.1 million, $0.1 million and $0.1 million was capitalized under these rules during the years ended September 30, 2018, 2017 and 2016, respectively. The tax benefit recognized from stock-based compensation exercises and vestings was $1.0 million for the year ended September 30, 2018.

SARs

Transactions for 2018 involving SARs for all plans are summarized as follows:

	Number of Shares Subject To Option	Weighted Average Exercise Price	Weighted Average Remaining Contractual Life (Years)	Aggregate Intrinsic Value (In thousands)
Outstanding at September 30, 2017	1,505,911	$ 48.64		
Granted in 2018	—	$ —		
Exercised in 2018	(206,823)	$ 35.70		
Forfeited in 2018	—	$ —		
Expired in 2018	—	$ —		
Outstanding at September 30, 2018	1,299,088	$ 50.70	1.77	$ 8,199
SARs exercisable at September 30, 2018	1,299,088	$ 50.70	1.77	$ 8,199
Shares available for future grant at September 30, 2018(1)	1,478,086			

(1) Includes shares available for options, SARs, restricted stock and performance share grants.

The Company did not grant any SARs during the years ended September 30, 2017 and 2016. The Company's SARs include both performance based and non-performance based SARs, but the performance conditions associated with the performance based SARs at the time of grant have all been subsequently met. The SARs are considered equity awards under the current authoritative guidance for stock-based compensation. The accounting for SARs is the same as the accounting for stock options.

The total intrinsic value of SARs exercised during the years ended September 30, 2018, 2017 and 2016 totaled approximately $4.4 million, $1.6 million, and $0.4 million, respectively. For the years ended September 30, 2017 and 2016, 5,000 SARs and 113,082 SARs, respectively, became fully vested. There were no SARs that became fully vested during the year ended September 30, 2018, and all SARs outstanding have been fully vested since fiscal 2017. The total fair value of the SARs that became vested during the years ended September 30, 2017 and 2016 was approximately $0.1 million and $1.2 million, respectively.

Restricted Share Awards

Transactions for 2018 involving restricted share awards for all plans are summarized as follows:

	Number of Restricted Share Awards	Weighted Average Fair Value per Award
Outstanding at September 30, 2017	20,000	$ 47.46
Granted in 2018	—	$ —
Vested in 2018	—	$ —
Forfeited in 2018	—	$ —
Outstanding at September 30, 2018	20,000	$ 47.46

The Company did not grant any restricted share awards (non-vested stock as defined by the current accounting literature) during the years ended September 30, 2017 and 2016. As of September 30, 2018, unrecognized compensation expense related to restricted share awards totaled approximately $0.2 million, which will be recognized over a weighted average period of 2.1 years.

Vesting restrictions for the 20,000 outstanding shares of non-vested restricted stock at September 30, 2018 will lapse in 2021.

Restricted Stock Units

Transactions for 2018 involving non-performance based restricted stock units for all plans are summarized as follows:

	Number of Restricted Stock Units	Weighted Average Fair Value per Award
Outstanding at September 30, 2017	233,199	$ 48.99
Granted in 2018	89,672	$ 51.23
Vested in 2018	(72,918)	$ 53.73
Forfeited in 2018	(4,637)	$ 46.04
Outstanding at September 30, 2018	245,316	$ 48.45

The Company also granted 87,143 and 101,943 non-performance based restricted stock units during the years ended September 30, 2017 and 2016, respectively. The weighted average fair value of such non-performance based restricted stock units granted in 2017 and 2016 was $52.13 per share and $35.89 per share, respectively. As of September 30, 2018, unrecognized compensation expense related to non-performance based restricted stock units totaled approximately $5.0 million, which will be recognized over a weighted average period of 2.2 years.

Vesting restrictions for the non-performance based restricted stock units outstanding at September 30, 2018 will lapse as follows: 2019 — 80,354 units; 2020 — 68,189 units; 2021 — 57,175 units; 2022 - 26,448 units; and 2023 - 13,150 units.

Performance Shares

Transactions for 2018 involving performance shares for all plans are summarized as follows:

	Number of Performance Shares	Weighted Average Fair Value per Award
Outstanding at September 30, 2017	527,748	$ 45.44
Granted in 2018	208,588	$ 50.95
Vested in 2018	(79,079)	$ 65.38
Forfeited in 2018	(15,967)	$ 57.15
Outstanding at September 30, 2018	641,290	$ 44.49

The Company also granted 184,148 and 309,996 performance shares during the years ended September 30, 2017 and 2016, respectively. The weighted average grant date fair value of such performance shares granted in 2017 and 2016 was $56.39 per share and $30.71 per share, respectively. As of September 30, 2018, unrecognized compensation expense related to performance shares totaled approximately $11.2 million, which will be recognized over a weighted average period of 1.7 years. Vesting restrictions for the outstanding performance shares at September 30, 2018 will lapse as follows: 2019 - 253,704 shares; 2020 - 181,446 shares; and 2021 - 206,140 shares.

Half of the performance shares granted during the years ended September 30, 2018, 2017 and 2016 must meet a performance goal related to relative return on capital over a three-year performance cycle. The performance goal over the respective performance cycles for the performance shares granted during 2018, 2017 and 2016 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 years ended September 30, 2018, 2017 and 2016 must meet a performance goal related to relative total shareholder return over a three-year performance cycle. The performance goal over the respective performance cycles for the total shareholder return performance shares ("TSR performance shares") granted during 2018, 2017 and 2016 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 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. In calculating the fair value of the award, the risk-free interest rate is based on the yield of a Treasury Note with a term commensurate with the remaining term of the TSR performance shares. The remaining term is based on the remainder of the performance cycle as of the date of grant. The expected volatility is based on historical daily stock price returns. For the TSR performance shares, it was assumed that there would be no forfeitures, based on the vesting term and the number of grantees. The following assumptions were used in estimating the fair value of the TSR performance shares at the date of grant:

	Year Ended September 30		
	2018	2017	2016
Risk-Free Interest Rate	1.96%	1.54%	1.26%
Remaining Term at Date of Grant (Years)	2.78	2.79	2.79
Expected Volatility	22.0%	22.6%	20.5%
Expected Dividend Yield (Quarterly)	N/A	N/A	N/A

Redeemable Preferred Stock

As of September 30, 2018, there were 10,000,000 shares of $1 par value Preferred Stock authorized but unissued.

Long-Term Debt

The outstanding long-term debt is as follows:

	At September 30 2018	At September 30 2017
	(Thousands)	
Medium-Term Notes(1):		
7.4% due March 2023 to June 2025	$ 99,000	$ 99,000
Notes(1)(3)(4):		
3.75% to 5.20% due December 2021 to September 2028	2,050,000	2,300,000
Total Long-Term Debt	2,149,000	2,399,000
Less Unamortized Discount and Debt Issuance Costs	17,635	15,319
Less Current Portion(2)	—	300,000
	$ 2,131,365	$ 2,083,681

(1) The Medium-Term Notes and Notes are unsecured.

(2) Current Portion of Long-Term Debt at September 30, 2017 consisted of $300.0 million of 6.50% notes that were scheduled to mature in April 2018. The Company redeemed those 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.

(3) The holders of these notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of both a change in control and a ratings downgrade to a rating below investment grade.

(4) The interest rate payable on $300.0 million of 4.75% notes and $300.0 million of 3.95% notes will be subject to adjustment from time to time, with a maximum of 2.00%, if certain change of control events involving a material subsidiary result in a downgrade of the credit rating assigned to the notes to below investment grade (or if the credit rating assigned to the notes is subsequently upgraded).

On August 17, 2018, the Company issued $300.0 million of 4.75% notes due September 1, 2028. After deducting underwriting discounts, commissions and other debt issuance costs, the net proceeds to the Company amounted to $295.0 million. The proceeds of this debt issuance were used for general corporate purposes, including the redemption of $250.0 million of 8.75% notes on September 7, 2018 that were scheduled to mature in May 2019. The Company redeemed those notes for $259.5 million, plus accrued interest. In the Utility and Pipeline and Storage segments, the call premium of $8.5 million was recorded to Unamortized Debt Expense on the Consolidated Balance Sheet as of September 30, 2018, and in the Exploration and Production segment, the call premium of $1.0 million was recorded to Interest Expense on Long-Term Debt on the Consolidated Income Statement during the year ended September 30, 2018.

On September 27, 2017, the Company issued $300.0 million of 3.95% notes due September 15, 2027. After deducting underwriting discounts, commissions and other debt issuance costs, the net proceeds to the Company amounted to $295.2 million. The proceeds of this debt issuance were used to redeem $300.0 million of 6.50% notes in October 2017, as discussed above in a footnote to the table of long-term debt outstanding.

As of September 30, 2018, the aggregate principal amounts of long-term debt maturing during the next five years and thereafter are as follows: zero in 2019, 2020 and 2021, $500.0 million in 2022, $549.0 million in 2023, and $1,100.0 million thereafter.

Short-Term Borrowings

The Company historically has obtained short-term funds either through bank loans or the issuance of commercial paper. On October 25, 2018, the Company entered into a Fourth Amended and Restated Credit Agreement (Credit Agreement) with a syndicate of 12 banks. This Credit Agreement provides a $750.0 million multi-year unsecured committed revolving credit facility through October 25, 2023. The Company also has an uncommitted line of credit with a financial institution for general corporate purposes. Borrowings under this uncommitted line of credit would be made at competitive market rates. The uncommitted credit line is revocable at the option of the financial institution and is reviewed on an annual basis. The Company anticipates that its uncommitted line of credit generally will be renewed or substantially replaced by a similar line. Other financial institutions may also provide the Company with uncommitted or discretionary lines of credit in the future. The total amount available to be issued under the Company's commercial paper program is $500.0 million. At September 30, 2018, the commercial paper program was backed by the Credit Agreement.

The Company did not have any outstanding commercial paper or short term notes payable to banks at September 30, 2018 and 2017.

Debt Restrictions

The Credit Agreement provides that the Company's debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter. For purposes of calculating the debt to capitalization ratio, the Company's total capitalization will be increased by adding back 50% of the aggregate after-tax amount of non-cash charges directly arising from any ceiling test impairment occurring on or after July 1, 2018, not to exceed $250 million. At September 30, 2018, the Company's debt to capitalization ratio (as calculated under the facility) was .52. The constraints specified in the Credit Agreement would have permitted an additional $1.46 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 September 30, 2018, the Company did not have any debt outstanding under the Credit Agreement.

Under the Company's existing indenture covenants at September 30, 2018, the Company would have been permitted to issue up to a maximum of $714.0 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 Part II, Item 7, Critical Accounting Estimates section above for a sensitivity analysis concerning commodity price changes and their impact on the ceiling test.

The Company's 1974 indenture pursuant to which $99.0 million (or 4.6%) of the Company's long-term debt (as of September 30, 2018) 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.

Note F — Fair Value Measurements

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

The following table sets forth, by level within the fair value hierarchy, the Company's financial assets and liabilities (as applicable) that were accounted for at fair value on a recurring basis as of September 30, 2018 and 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 September 30, 2018				
	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
	(Dollars in thousands)				
Assets:					
Cash Equivalents — Money Market Mutual Funds	$ 215,272	$ —	$ —	$ —	$ 215,272
Derivative Financial Instruments:					
Commodity Futures Contracts — Gas	1,075	—	—	(1,075)	—
Over the Counter Swaps — Gas and Oil	—	26,074	—	(17,041)	9,033
Foreign Currency Contracts	—	443	—	(443)	—
Other Investments:					
Balanced Equity Mutual Fund	38,468	—	—	—	38,468
Fixed Income Mutual Fund	51,331	—	—	—	51,331
Common Stock — Financial Services Industry	2,776	—	—	—	2,776
Hedging Collateral Deposits	3,441	—	—	—	3,441
Total	$ 312,363	$ 26,517	$ —	$ (18,559)	$ 320,321
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts — Gas	$ 2,412	$ —	$ —	$ (1,075)	$ 1,337
Over the Counter Swaps — Gas and Oil	—	64,224	—	(17,041)	47,183
Foreign Currency Contracts	—	959	—	(443)	516
Total	$ 2,412	$ 65,183	$ —	$ (18,559)	$ 49,036
Total Net Assets/(Liabilities)	$ 309,951	$ (38,666)	$ —	$ —	$ 271,285

Recurring Fair Value Measures	At Fair Value as of September 30, 2017				
	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
	(Dollars in thousands)				
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.

Derivative Financial Instruments

At September 30, 2018 and 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 of $3.4 million (at September 30, 2018) and $1.7 million (at September 30, 2017), which are associated with these futures contracts, have been reported in Level 1 as well. The derivative financial instruments reported in Level 2 at September 30, 2018 and 2017 consist of natural gas price swap agreements used in the Company's Exploration and Production and Energy Marketing segments, the crude oil price swap agreements used in the Company's Exploration and Production segment and foreign currency contracts used in the Company's Exploration and Production segment. The fair value of the Level 2 price swap agreements is based on an internal, discounted cash flow model that uses observable inputs (i.e. LIBOR based discount rates and basis differential information, if applicable, at active natural gas and crude oil trading markets). The fair value of the Level 2 foreign currency contracts is determined using the market approach based on observable market transactions of forward Canadian currency rates.

The 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 September 30, 2018, 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 years ended September 30, 2018 and 2017, there were no assets or liabilities measured at fair value and classified as Level 3. For the years ended September 30, 2018 and September 30, 2017, no transfers in or out of Level 1 or Level 2 occurred.

Note G — 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:

	At September 30			
	2018 Carrying Amount	2018 Fair Value	2017 Carrying Amount	2017 Fair Value
	(Thousands)			
Long-Term Debt	$ 2,131,365	$ 2,121,861	$ 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

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

	At September 30	
	2018	2017
	(Thousands)	
Life Insurance Contracts	$ 39,970	$ 39,355
Equity Mutual Fund	38,468	37,033
Fixed Income Mutual Fund	51,331	45,727
Marketable Equity Securities	2,776	3,150
	$ 132,545	$ 125,265

Investments in life insurance contracts are stated at their cash surrender values or net present value. Investments in an equity mutual fund, a fixed income mutual fund and the stock of an insurance company (marketable equity securities) are stated at fair value based on quoted market prices. The gross unrealized gain on the equity mutual fund was $10.7 million and $9.9 million at September 30, 2018 and 2017, respectively. A sale of shares in the equity mutual fund during the year ended September 30, 2018 resulted in $1.5 million of cash proceeds and a realized gain of $0.4 million. The gross unrealized loss on the fixed income mutual fund was $0.8 million and less than $0.1 million at September 30, 2018 and 2017, respectively. A sale of shares in the fixed income mutual fund during the year ended September 30, 2018 resulted in $1.5 million of cash proceeds and a realized loss of less than $0.1 million. The gross unrealized gain on the marketable equity securities was $1.8 million and $2.2 million at September 30, 2018 and 2017, respectively. 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 length of the Company’s combined cash flow and fair value 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 September 30, 2018 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 September 30, 2018, the Company had the following commodity derivative contracts (swaps and futures contracts) outstanding:

Commodity	Units	
Natural Gas	120.1	Bcf (short positions)
Natural Gas	1.8	Bcf (long positions)
Crude Oil	4,188,000	Bbls (short positions)

As of September 30, 2018, the Company was hedging a total of $86.5 million of forecasted transportation costs denominated in Canadian dollars with foreign currency forward contracts (long positions).

As of September 30, 2018, the Company had $37.4 million ($28.6 million after tax) of net hedging losses included in the accumulated other comprehensive income (loss) balance. It is expected that $23.7 million ($17.0 million after tax) of such unrealized losses will be reclassified into the Consolidated Statement of Income within the next 12 months as the underlying hedged transactions are recorded in earnings.

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Year Ended September 30, 2018 and 2017 (Dollar Amounts in Thousands)

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 Year Ended September 30,		Location of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion)	Amount of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income (Loss) on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion) for the Year Ended September 30,		Location of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing)	Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income (Ineffective Portion and Amount Excluded from Effectiveness Testing) for the Year Ended September 30,	
	2018	2017		2018	2017		2018	2017
Commodity Contracts	$(70,905)	$ 2,811	Operating Revenue	$ 423	$ 83,983	Operating Revenue	$ (782)	$ (100)
Commodity Contracts	701	(164)	Purchased Gas	952	(1,921)	Not Applicable	—	—
Foreign Currency Contracts	(3,899)	2,700	Operation and Maintenance Expense	(2,564)	(457)	Not Applicable	—	—
Total	$(74,103)	$ 5,347		$ (1,189)	$ 81,605		$ (782)	$ (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 September 30, 2018, the Company's Energy Marketing segment had fair value hedges covering approximately 27.7 Bcf (27.1 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 Derivative Recognized in the Consolidated Statement of Income for the Year Ended September 30, 2018	Amount of Gain or (Loss) on Hedged Item Recognized in the Consolidated Statement of Income for the Year Ended September 30, 2018
		(In thousands)	
Commodity Contracts	Operating Revenues	$ (1,289)	$ 1,289
Commodity Contracts	Purchased Gas	(238)	238
		$ (1,527)	**$ 1,527**

Credit Risk

The Company may be exposed to credit risk on any of the derivative financial instruments that are in a gain position. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check, and then on a quarterly basis monitors counterparty credit exposure. The majority of the Company's counterparties are financial institutions and energy traders. The Company has over-the-counter swap positions and applicable foreign currency forward contracts with eighteen counterparties of which three are in a net gain position. On average, the Company had $3.0 million of credit exposure per counterparty in a gain position at September 30, 2018. The maximum credit exposure per counterparty in a gain position at September 30, 2018 was $5.6 million. As of September 30, 2018, 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 September 30, 2018, fifteen of the eighteen 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 September 30, 2018, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $9.0 million according to the Company's internal model (discussed in Note F — Fair Value Measurements). At September 30, 2018, the fair market value of the derivative financial instrument liabilities with a credit-risk related contingency feature was $40.3 million according to the Company's internal model. 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 September 30, 2018.

For its exchange traded futures contracts, the Company was required to post $3.4 million in hedging collateral deposits as of September 30, 2018. 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 A under Hedging Collateral Deposits.

Note H — Retirement Plan and Other Post-Retirement Benefits

The Company has a tax-qualified, noncontributory, defined-benefit retirement plan (Retirement Plan). The Retirement Plan covers certain non-collectively bargained employees hired before July 1, 2003 and certain collectively bargained employees hired before November 1, 2003. Certain non-collectively bargained employees hired after June 30, 2003 and certain collectively bargained employees hired after October 31, 2003 are eligible for a Retirement Savings Account benefit provided under the Company's defined contribution Tax-Deferred Savings Plans. Costs associated with the Retirement Savings Account were \$3.5 million, \$2.9 million and \$2.6 million for the years ended September 30, 2018, 2017 and 2016, respectively. Costs associated with the Company's contributions to the Tax-Deferred Savings Plans, exclusive of the costs associated with the Retirement Savings Account, were \$6.2 million, \$5.9 million, and \$5.9 million for the years ended September 30, 2018, 2017 and 2016, respectively.

The Company provides health care and life insurance benefits (other post-retirement benefits) for a majority of its retired employees. The other post-retirement benefits cover certain non-collectively bargained employees hired before January 1, 2003 and certain collectively bargained employees hired before October 31, 2003.

The Company's policy is to fund the Retirement Plan with at least an amount necessary to satisfy the minimum funding requirements of applicable laws and regulations and not more than the maximum amount deductible for federal income tax purposes. The Company has established VEBA trusts for its other post-retirement benefits. Contributions to the VEBA trusts are tax deductible, subject to limitations contained in the Internal Revenue Code and regulations and are made to fund employees' other post-retirement benefits, as well as benefits as they are paid to current retirees. In addition, the Company has established 401(h) accounts for its other post-retirement benefits. They are separate accounts within the Retirement Plan trust used to pay retiree medical benefits for the associated participants in the Retirement Plan. Although these accounts are in the Retirement Plan trust, for funding status purposes as shown below, the 401(h) accounts are included in Fair Value of Assets under Other Post-Retirement Benefits. Contributions are tax-deductible when made, subject to limitations contained in the Internal Revenue Code and regulations.

The expected return on Retirement Plan assets, a component of net periodic benefit cost shown in the tables below, is applied to the market-related value of plan assets. The market-related value of plan assets is the market value as of the measurement date adjusted for variances between actual returns and expected returns (from previous years) that have not been reflected in net periodic benefit costs. The expected return on other post-retirement benefit assets (i.e. the VEBA trusts and 401(h) accounts), which is a component of net periodic benefit cost shown in the tables below, is applied to the fair value of assets as of the measurement date.

Reconciliations of the Benefit Obligations, Plan Assets and Funded Status, as well as the components of Net Periodic Benefit Cost and the Weighted Average Assumptions of the Retirement Plan and other post-retirement benefits are shown in the tables below. The date used to measure the Benefit Obligations, Plan Assets and Funded Status is September 30 for fiscal years 2018, 2017 and 2016.

	Retirement Plan			Other Post-Retirement Benefits		
	Year Ended September 30			Year Ended September 30		
	2018	2017	2016	2018	2017	2016
	(Thousands)					
Change in Benefit Obligation						
Benefit Obligation at Beginning of Period	$1,054,826	$1,097,421	$1,026,190	$462,619	$526,138	$ 464,987
Service Cost	9,921	11,969	11,710	1,830	2,449	2,331
Interest Cost	33,006	38,383	42,315	14,801	19,007	20,386
Plan Participants' Contributions	—	—	—	2,894	2,717	2,558
Retiree Drug Subsidy Receipts	—	—	—	1,545	1,553	1,925
Actuarial (Gain) Loss	(50,218)	(32,466)	76,309	(21,039)	(62,215)	60,402
Benefits Paid	(61,845)	(60,481)	(59,103)	(26,664)	(27,030)	(26,451)
Benefit Obligation at End of Period	$ 985,690	$1,054,826	$1,097,421	$435,986	$462,619	$ 526,138
Change in Plan Assets						
Fair Value of Assets at Beginning of Period	$ 910,719	$ 869,775	$ 834,870	$514,017	$494,320	$ 477,959
Actual Return on Plan Assets	42,652	84,279	87,008	20,657	40,157	37,415
Employer Contributions	32,980	17,146	7,000	2,896	3,853	2,839
Plan Participants' Contributions	—	—	—	2,894	2,717	2,558
Benefits Paid	(61,845)	(60,481)	(59,103)	(26,664)	(27,030)	(26,451)
Fair Value of Assets at End of Period	$ 924,506	$ 910,719	$ 869,775	$513,800	$514,017	$ 494,320
Net Amount Recognized at End of Period (Funded Status)	$ (61,184)	$ (144,107)	$ (227,646)	$ 77,814	$ 51,398	$ (31,818)
Amounts Recognized in the Balance Sheets Consist of:						
Non-Current Liabilities	$ (61,184)	$ (144,107)	$ (227,646)	$ (4,919)	$ (4,972)	$ (49,467)
Non-Current Assets	—	—	—	82,733	56,370	17,649
Net Amount Recognized at End of Period	$ (61,184)	$ (144,107)	$ (227,646)	$ 77,814	$ 51,398	$ (31,818)
Accumulated Benefit Obligation	$ 946,763	$1,010,179	$1,039,408	N/A	N/A	N/A
Weighted Average Assumptions Used to Determine Benefit Obligation at September 30						
Discount Rate	4.30%	3.77%	3.60%	4.31%	3.81%	3.70%
Rate of Compensation Increase	4.70%	4.70%	4.70%	4.70%	4.70%	4.70%

	Retirement Plan			Other Post-Retirement Benefits		
	Year Ended September 30			Year Ended September 30		
	2018	2017	2016	2018	2017	2016
	(Thousands)					
Components of Net Periodic Benefit Cost						
Service Cost	$ 9,921	$ 11,969	$ 11,710	$ 1,830	$ 2,449	$ 2,331
Interest Cost	33,006	38,383	42,315	14,801	19,007	20,386
Expected Return on Plan Assets	(61,715)	(59,718)	(59,369)	(31,482)	(31,458)	(31,535)
Amortization of Prior Service Cost (Credit)	938	1,058	1,234	(429)	(429)	(912)
Recognition of Actuarial Loss(1)	37,205	42,687	32,248	10,558	18,415	5,530
Net Amortization and Deferral for Regulatory Purposes	9,027	469	3,957	15,028	6,108	17,123
Net Periodic Benefit Cost	$ 28,382	$ 34,848	$ 32,095	$ 10,306	$ 14,092	$ 12,923
Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost at September 30						
Effective Discount Rate for Benefit Obligations	3.77%	3.60%	4.25%	3.81%	3.70%	4.50%
Effective Rate for Interest on Benefit Obligations	3.23%	3.60%	4.25%	3.29%	3.70%	4.50%
Effective Discount Rate for Service Cost	4.00%	3.60%	4.25%	4.10%	3.70%	4.50%
Effective Rate for Interest on Service Cost	3.73%	3.60%	4.25%	3.98%	3.70%	4.50%
Expected Return on Plan Assets	7.00%	7.00%	7.25%	6.25%	6.50%	6.75%
Rate of Compensation Increase	4.70%	4.70%	4.75%	4.70%	4.70%	4.75%

(1) Distribution Corporation's New York jurisdiction calculates the amortization of the actuarial loss on a vintage year basis over 10 years, as mandated by the NYPSC. All the other subsidiaries of the Company utilize the corridor approach.

The Net Periodic Benefit Cost in the table above includes the effects of regulation. The Company recovers pension and other post-retirement benefit costs in its Utility and Pipeline and Storage segments in accordance with the applicable regulatory commission authorizations. Certain of those commission authorizations established tracking mechanisms which allow the Company to record the difference between the amount of pension and other post-retirement benefit costs recoverable in rates and the amounts of such costs as determined under the existing authoritative guidance as either a regulatory asset or liability, as appropriate. Any activity under the tracking mechanisms (including the amortization of pension and other post-retirement regulatory assets and liabilities) is reflected in the Net Amortization and Deferral for Regulatory Purposes line item above.

In addition to the Retirement Plan discussed above, the Company also has Non-Qualified benefit plans that cover a group of management employees designated by the Chief Executive Officer of the Company. These plans provide for defined benefit payments upon retirement of the management employee, or to the spouse upon death of the management employee. The net periodic benefit costs associated with these plans were $6.8 million, $7.6 million and $7.5 million in 2018, 2017 and 2016, respectively. The accumulated benefit obligations for the plans were $70.6 million, $72.5 million and $72.4 million at September 30, 2018, 2017 and 2016, respectively. The projected benefit obligations for the plans were $86.1 million, $88.9 million and $91.7 million at September 30, 2018, 2017 and 2016, respectively. At September 30, 2018, $11.5 million of the projected benefit obligation is recorded in Other Accruals and Current Liabilities and the remaining $74.6 million is recorded in Other Deferred Credits on the Consolidated Balance Sheets. At September 30, 2017, $14.1 million of the projected benefit obligation was recorded in Other Accruals and Current Liabilities and the remaining $74.8 million was recorded in Other Deferred Credits on the Consolidated Balance Sheets. At September 30, 2016, $9.8 million of the projected benefit obligation was recorded in Other Accruals and Current Liabilities and the remaining $81.9 million was recorded in Other Deferred Credits on the Consolidated Balance Sheets. The weighted average discount rates for these plans were 4.02%, 3.22% and 2.80% as of September 30, 2018, 2017 and 2016, respectively and the weighted average rates of compensation increase for these plans were 7.75%, 7.75% and 7.75% as of September 30, 2018, 2017 and 2016, respectively.

The cumulative amounts recognized in accumulated other comprehensive income (loss), regulatory assets, and regulatory liabilities through fiscal 2018, the changes in such amounts during 2018, as well as the amounts expected to be recognized in net periodic benefit cost in fiscal 2019 are presented in the table below:

	Retirement Plan	Other Post-Retirement Benefits	Non-Qualified Benefit Plans
		(Thousands)	
Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities(1)			
Net Actuarial Gain (Loss)	$ (135,527)	$ 1,193	$ (22,818)
Prior Service (Cost) Credit	(5,195)	3,258	—
Net Amount Recognized	$ (140,722)	$ 4,451	$ (22,818)
Changes to Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities Recognized During Fiscal 2018(1)			
Decrease (Increase) in Actuarial Loss, excluding amortization (2)	$ 31,155	$ 10,213	$ (2,035)
Change due to Amortization of Actuarial Loss	37,205	10,558	3,549
Prior Service (Cost) Credit	938	(429)	—
Net Change	$ 69,298	$ 20,342	$ 1,514
Amounts Expected to be Recognized in Net Periodic Benefit Cost in the Next Fiscal Year(1)			
Net Actuarial Loss	$ (32,096)	$ (5,962)	$ (3,558)
Prior Service (Cost) Credit	(826)	429	—
Net Amount Expected to be Recognized	$ (32,922)	$ (5,533)	$ (3,558)

(1) Amounts presented are shown before recognizing deferred taxes.

(2) Amounts presented include the impact of actuarial gains/losses related to return on assets, as well as the Actuarial (Gain) Loss amounts presented in the Change in Benefit Obligation.

In order to adjust the funded status of its pension (tax-qualified and non-qualified) and other post-retirement benefit plans at September 30, 2018, the Company recorded a $75.3 million decrease to Other Regulatory Assets in the Company's Utility and Pipeline and Storage segments and a $15.9 million (pre-tax) increase to Accumulated Other Comprehensive Income.

The effect of the discount rate change for the Retirement Plan in 2018 was to decrease the projected benefit obligation of the Retirement Plan by $58.1 million. The mortality improvement projection scale was updated, which decreased the projected benefit obligation of the Retirement Plan in 2018 by $3.3 million. Other actuarial experience increased the projected benefit obligation for the Retirement Plan in 2018 by $11.2 million. The effect of the discount rate change for the Retirement Plan in 2017 was to decrease the projected benefit obligation of the Retirement Plan by $20.5 million. The effect of the discount rate change for the Retirement Plan in 2016 was to increase the projected benefit obligation of the Retirement Plan by $78.5 million.

The Company made cash contributions totaling $33.0 million to the Retirement Plan during the year ended September 30, 2018. The Company expects that the annual contribution to the Retirement Plan in 2019 will be in the range of $29.0 million to $35.0 million.

The following Retirement Plan benefit payments, which reflect expected future service, are expected to be paid by the Retirement Plan during the next five years and the five years thereafter: $65.7 million in 2019; $65.9 million in 2020; $66.3 million in 2021; $66.5 million in 2022; $66.6 million in 2023; and $330.9 million in the five years thereafter.

The effect of the discount rate change in 2018 was to decrease the other post-retirement benefit obligation by $25.8 million. The mortality improvement projection scale was updated, which decreased the other post-retirement benefit obligation in 2018 by $2.4 million. Other actuarial experience increased the other post-retirement benefit obligation in 2018 by $7.3 million, the majority of which was attributable to a revision in assumed per-capita claims cost, premiums, retiree contributions and retiree drug subsidy assumptions based on actual experience.

The effect of the discount rate change in 2017 was to decrease the other post-retirement benefit obligation by $6.2 million. The mortality improvement projection scale was updated, which decreased the other post-retirement benefit obligation in 2017 by $5.7 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2017 by $50.3 million primarily attributable to a revision in assumed per-capita claims cost, premiums, retiree contributions and retiree drug subsidy assumptions based on actual experience.

The effect of the discount rate change in 2016 was to increase the other post-retirement benefit obligation by $49.4 million. Other actuarial experience increased the other post-retirement benefit obligation in 2016 by $11.0 million primarily attributable to a revision in assumed per-capita claims cost, premiums, participant contributions and drug subsidy assumptions based on actual experience.

The Medicare Prescription Drug, Improvement, and Modernization Act of 2003 provides for a prescription drug benefit under Medicare (Medicare Part D), as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D.

The estimated gross other post-retirement benefit payments and gross amount of Medicare Part D prescription drug subsidy receipts are as follows (dollars in thousands):

	Benefit Payments	Subsidy Receipts
2019	$ 27,821	$ (1,858)
2020	$ 28,692	$ (1,996)
2021	$ 29,455	$ (2,128)
2022	$ 29,979	$ (2,260)
2023	$ 30,426	$ (2,386)
2024 through 2028	$ 153,855	$ (13,325)

Assumed health care cost trend rates as of September 30 were:

	2018	2017	2016
Rate of Medical Cost Increase for Pre Age 65 Participants	5.59% (1)	5.67% (1)	5.75% (1)
Rate of Medical Cost Increase for Post Age 65 Participants	4.75% (1)	4.75% (1)	4.75% (1)
Annual Rate of Increase in the Per Capita Cost of Covered Prescription Drug Benefits	7.89% (1)	8.45% (1)	9.00% (1)
Annual Rate of Increase in the Per Capita Medicare Part B Reimbursement	4.75% (1)	4.75% (1)	4.75% (1)
Annual Rate of Increase in the Per Capita Medicare Part D Subsidy	7.18% (1)	7.33% (1)	7.20% (1)

(1) It was assumed that this rate would gradually decline to 4.5% by 2039.

The health care cost trend rate assumptions used to calculate the per capita cost of covered medical care benefits have a significant effect on the amounts reported. If the health care cost trend rates were increased by 1% in each year, the other post-retirement benefit obligation as of October 1, 2018 would increase by $51.3 million. This 1% change would also have increased the aggregate of the service and interest cost components of net periodic post-retirement benefit cost for 2018 by $2.9 million. If the health care cost trend rates were decreased by 1% in each year, the other post-retirement benefit obligation as of October 1, 2018 would decrease by $42.8 million. This 1% change would also have decreased the aggregate of the service and interest cost components of net periodic post-retirement benefit cost for 2018 by $2.1 million.

The Company made cash contributions totaling $2.8 million to its VEBA trusts during the year ended September 30, 2018. In addition, the Company made direct payments of $0.1 million to retirees not covered by the VEBA trusts and 401(h) accounts during the year ended September 30, 2018. The Company expects that the annual contribution to its VEBA trusts in 2019 will be in the range of $2.5 million to $4.0 million.

Investment Valuation

The Retirement Plan assets and other post-retirement benefit assets are valued under the current fair value framework. See Note F — Fair Value Measurements for further discussion regarding the definition and levels of fair value hierarchy established by the authoritative guidance.

The inputs or methodologies used for valuing securities are not necessarily an indication of the risk associated with investing in those securities. Below is a listing of the major categories of plan assets held as of September 30, 2018 and 2017, as well as the associated level within the fair value hierarchy in which the fair value measurements in their entirety fall, based on the lowest level input that is significant to the fair value measurement in its entirety (dollars in thousands):

	Total Fair Value Amounts at September 30, 2018	Level 1	Level 2	Level 3	Measured at NAV(7)
Retirement Plan Investments					
Domestic Equities(1)	$ 223,300	$ 139,885	$ —	$ —	$ 83,415
International Equities(2)	100,832	—	—	—	100,832
Global Equities(3)	85,942	—	—	—	85,942
Domestic Fixed Income(4)	434,392	1,640	382,348	—	50,404
International Fixed Income(5)	416	416	—	—	—
Global Fixed Income(6)	72,382	—	—	—	72,382
Real Estate	53,878	—	—	3,194	50,684
Cash Held in Collective Trust Funds	26,191	—	—	—	26,191
Total Retirement Plan Investments	997,333	141,941	382,348	3,194	469,850
401(h) Investments	(67,817)	(9,695)	(26,114)	(218)	(31,790)
Total Retirement Plan Investments (excluding 401(h) Investments)	$ 929,516	$ 132,246	$ 356,234	$ 2,976	$ 438,060
Miscellaneous Accruals, Interest Receivables, and Non-Interest Cash	(5,010)				
Total Retirement Plan Assets	$ 924,506				

	Total Fair Value Amounts at September 30, 2017	Level 1	Level 2	Level 3	Measured at NAV(7)
Retirement Plan Investments					
Domestic Equities(1)	$ 290,716	$ 209,421	$ —	$ —	$ 81,295
International Equities(2)	123,069	—	—	—	123,069
Global Equities(3)	121,008	—	—	—	121,008
Domestic Fixed Income(4)	348,501	1,664	346,837	—	—
International Fixed Income(5)	422	422	—	—	—
Global Fixed Income(6)	75,428	—	—	—	75,428
Real Estate	3,391	—	—	3,391	—
Cash Held in Collective Trust Funds	26,058	—	—	—	26,058
Total Retirement Plan Investments	988,593	211,507	346,837	3,391	426,858
401(h) Investments	(64,728)	(14,026)	(23,001)	(225)	(27,476)
Total Retirement Plan Investments (excluding 401(h) Investments)	$ 923,865	$ 197,481	$ 323,836	$ 3,166	$ 399,382
Miscellaneous Accruals, Interest Receivables, and Non-Interest Cash	(13,146)				
Total Retirement Plan Assets	$ 910,719				

(1) Domestic Equities include mostly collective trust funds, common stock, and exchange traded funds.
(2) International Equities are comprised of collective trust funds.
(3) Global Equities are comprised of collective trust funds.
(4) Domestic Fixed Income securities include mostly collective trust funds, corporate/government bonds and mortgages, and exchange traded funds.
(5) International Fixed Income securities are comprised mostly of an exchange traded fund.

(6) Global Fixed Income securities are comprised of a collective trust fund.
(7) Reflects the authoritative guidance related to investments measured at the net asset value (NAV) practical expedient.

	Total Fair Value Amounts at September 30, 2018	Level 1	Level 2	Level 3	Measured at NAV(1)
Other Post-Retirement Benefit Assets held in VEBA Trusts					
Collective Trust Funds — Domestic Equities	$ 125,295	$ —	$ —	$ —	$125,295
Collective Trust Funds — International Equities	47,245	—	—	—	47,245
Exchange Traded Funds — Fixed Income	265,667	265,667	—	—	—
Cash Held in Collective Trust Funds	7,894	—	—	—	7,894
Total VEBA Trust Investments	446,101	265,667	—	—	180,434
401(h) Investments	67,817	9,695	26,114	218	31,790
Total Investments (including 401(h) Investments)	$ 513,918	$ 275,362	$ 26,114	$ 218	$212,224
Miscellaneous Accruals (Including Current and Deferred Taxes, Claims Incurred But Not Reported, Administrative)	(118)				
Total Other Post-Retirement Benefit Assets	$ 513,800				

	Total Fair Value Amounts at September 30, 2017	Level 1	Level 2	Level 3	Measured at NAV(1)
Other Post-Retirement Benefit Assets held in VEBA Trusts					
Collective Trust Funds — Domestic Equities	$ 130,864	$ —	$ —	$ —	$130,864
Collective Trust Funds — International Equities	52,063	—	—	—	52,063
Exchange Traded Funds — Fixed Income	256,099	256,099	—	—	—
Cash Held in Collective Trust Funds	9,569	—	—	—	9,569
Total VEBA Trust Investments	448,595	256,099	—	—	192,496
401(h) Investments	64,728	14,026	23,001	225	27,476
Total Investments (including 401(h) Investments)	$ 513,323	$ 270,125	$ 23,001	$ 225	$219,972
Miscellaneous Accruals (Including Current and Deferred Taxes, Claims Incurred But Not Reported, Administrative)	694				
Total Other Post-Retirement Benefit Assets	$ 514,017				

(1) Reflects the authoritative guidance related to investments measured at the net asset value (NAV) practical expedient.

The fair values disclosed in the above tables may not be indicative of net realizable value or reflective of future fair values. Furthermore, although the Company believes its valuation methods are appropriate and consistent with other market participants, the use of different methodologies or assumptions to determine the fair value of certain financial instruments could result in a different fair value measurement at the reporting date.

The following tables provide a reconciliation of the beginning and ending balances of the Retirement Plan and other post-retirement benefit assets measured at fair value on a recurring basis where the determination of fair value includes significant unobservable inputs (Level 3). For the years ended September 30, 2018 and September 30, 2017, there were no transfers from Level 1 to Level 2. In addition, as shown in the following tables, there were no transfers in or out of Level 3.

	Retirement Plan Level 3 Assets (Thousands)		
	Real Estate	Excluding 401(h) Investments	Total
Balance at September 30, 2016	$ 2,970	$ (188)	$ 2,782
Unrealized Gains/(Losses)	421	(37)	384
Balance at September 30, 2017	3,391	(225)	3,166
Unrealized Gains/(Losses)	188	(19)	169
Sales	(385)	26	(359)
Balance at September 30, 2018	$ 3,194	$ (218)	$ 2,976

	Other Post-Retirement Benefit Level 3 Assets (Thousands)
	401(h) Investments
Balance at September 30, 2016	$ 188
Unrealized Gains/(Losses)	37
Balance at September 30, 2017	225
Unrealized Gains/(Losses)	19
Sales	(26)
Balance at September 30, 2018	$ 218

The Company's assumption regarding the expected long-term rate of return on plan assets is 6.75% (Retirement Plan) and 6.00% (other post-retirement benefits), effective for fiscal 2019. The return assumption reflects the anticipated long-term rate of return on the plan's current and future assets. The Company utilizes projected capital market conditions and the plan's target asset class and investment manager allocations to set the assumption regarding the expected return on plan assets.

The long-term investment objective of the Retirement Plan trust, the VEBA trusts and the 401(h) accounts is to achieve the target total return in accordance with the Company's risk tolerance. Assets are diversified utilizing a mix of equities, fixed income and other securities (including real estate). The target allocation for the Retirement Plan and the VEBA trusts (including 401(h) accounts) is 30-50% equity securities, 50-70% fixed income securities (including return-seeking investments) and 0-15% other (including return-seeking investments). Risk tolerance is established through consideration of plan liabilities, plan funded status and corporate financial condition. The assets of the Retirement Plan trusts, VEBA trusts and the 401(h) accounts have no significant concentrations of risk in any one country (other than the United States), industry or entity.

Investment managers are retained to manage separate pools of assets. Comparative market and peer group performance of individual managers and the total fund are monitored on a regular basis, and reviewed by the Company's Retirement Committee on at least a quarterly basis.

The Company determines the service and interest cost components of net periodic benefit cost using the spot rate approach, which uses individual spot rates along the yield curve that correspond to the timing of each benefit payment in order to determine the discount rate. The individual spot rates along the yield curve are determined by an above mean methodology in that the coupon interest rates that are in the lower 50th percentile are excluded based on the assumption that the Company would not utilize more expensive (i.e. lower yield) instruments to settle its liabilities.

Note I — 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 September 30, 2018, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites will be approximately $7.6 million, which includes a $4.1 million estimated minimum liability to remediate a former manufactured gas plant site located in New York. In March 2018, the NYDEC issued a Record of Decision for this New York site and the minimum liability reflects the remedy selected in the Record of Decision. The Company's liability for such clean-up costs has been recorded in Other Deferred Credits on the Consolidated Balance Sheet at September 30, 2018. The Company expects to recover its environmental clean-up costs through rate recovery over a period of approximately 4 years and 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 could have an adverse financial impact on the Company.

Northern Access Project

On February 3, 2017, Supply Corporation and Empire received FERC approval of the Northern Access 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. On August 6, 2018, the FERC issued an Order finding that the NYDEC exceeded the statutory time frame to take action under the Clean Water Act and, therefore, waived its opportunity to approve or deny the Water Quality Certification. Rehearing requests have been filed at FERC. In light of these pending legal actions and the need to complete necessary project development activities in advance of construction, the target in-service date for the project is expected to be no earlier than the first half of fiscal 2022. As a result of the decision of the NYDEC, Supply Corporation and Empire evaluated the capitalized project costs for impairment as of September 30, 2018 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 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 $76.2 million at September 30, 2018. The project costs are included within Property, Plant and Equipment and Deferred Charges on the Consolidated Balance Sheet.

Other

The Company, in its Utility segment, Energy Marketing segment, and Exploration and Production segment, has entered into contractual commitments in the ordinary course of business, including commitments to purchase gas, transportation, and storage service to meet customer gas supply needs. The future gas purchase, transportation and storage contract commitments during the next five years and thereafter are as follows: $297.9 million in 2019, $102.9 million in 2020, $86.6 million in 2021, $152.5 million in 2022, $162.8 million in 2023 and $1,606.0 million thereafter. Gas prices within the gas purchase contracts are variable based on NYMEX prices adjusted for basis. In the Utility segment, these costs are subject to state commission review, and are being recovered in customer rates. Management believes that, to the extent any stranded pipeline costs are generated by the unbundling of services in the Utility segment's service territory, such costs will be recoverable from customers.

The Company has entered into leases for the use of compressors, drilling rigs, buildings and other items. These leases are accounted for as operating leases. The future lease commitments during the next five years and thereafter are as follows: $18.6 million in 2019, $4.6 million in 2020, $4.0 million in 2021, $3.2 million in 2022, $2.7 million in 2023 and $12.4 million thereafter.

The Company, in its Pipeline and Storage segment, Gathering segment and Utility segment, has entered into several contractual commitments associated with various pipeline, compressor and gathering system modernization and expansion projects. As of September 30, 2018, the future contractual commitments related to the system modernization and expansion projects are $105.1 million in 2019, $6.8 million in 2020, $6.1 million in 2021, $5.1 million in 2022, $3.4 million in 2023 and $13.3 million thereafter.

The Company, in its Exploration and Production segment, has entered into contractual obligations associated with hydraulic fracturing and fuel. The future contractual commitments are $86.2 million in 2019 and $24.8 million in 2020. There are no contractual commitments extending beyond 2020.

The Company is involved in other litigation arising in the normal course of business. In addition to the regulatory matters discussed in Note C — Regulatory Matters, the Company is involved in other regulatory matters arising in the normal course of business. These other litigation and regulatory 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 J — 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 Exploration and Production segment, through Seneca, is engaged in exploration for and development of natural gas and oil reserves in California and the Appalachian region of the United States.

The Pipeline and Storage segment operations are regulated by the FERC for both Supply Corporation and Empire. Supply Corporation transports and stores natural gas for utilities (including Distribution Corporation), natural gas marketers (including NFR), exploration and production companies (including Seneca) and pipeline companies in the northeastern United States markets. Empire transports and stores natural gas for major industrial companies, utilities (including Distribution Corporation) and power producers in New York State. Empire also transports natural gas for natural gas marketers along with exploration and production companies from natural gas producing areas in Pennsylvania to markets in New York and to interstate pipeline delivery points for additional markets in the northeastern United States and Canada.

The Gathering segment is comprised of Midstream Company's operations. Midstream Company builds, owns and operates natural gas processing and pipeline gathering facilities in the Appalachian region and currently provides gathering services to Seneca.

The Utility segment operations are regulated by the NYPSC and the PaPUC and are carried out by Distribution Corporation. Distribution Corporation sells natural gas to retail customers and provides natural gas transportation services in western New York and northwestern Pennsylvania.

The Energy Marketing segment is comprised of NFR's operations. NFR markets natural gas to industrial, wholesale, commercial, public authority and residential customers primarily in western and central New York and northwestern Pennsylvania, offering competitively priced natural gas for its customers.

The data presented in the tables below reflects financial information for the segments and reconciliations to consolidated amounts. The accounting policies of the segments are the same as those described in Note A — Summary of Significant Accounting Policies. Sales of products or services between segments are billed at regulated rates or at market rates, as applicable. 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.

	Year Ended September 30, 2018								
	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)								
Revenue from External Customers(1)	$ 564,547	$ 210,345	$ 41	$ 674,726	$ 137,748	$ 1,587,407	$ 4,601	$ 660	$ 1,592,668
Intersegment Revenues	$ —	$ 89,981	$ 107,856	$ 12,800	$ 826	$ 211,463	$ —	$ (211,463)	$ —
Interest Income	$ 1,479	$ 2,748	$ 1,106	$ 1,591	$ 685	$ 7,609	$ 388	$ (1,231)	$ 6,766
Interest Expense	$ 54,288	$ 31,383	$ 9,560	$ 26,753	$ 22	$ 122,006	$ —	$ (7,484)	$ 114,522
Depreciation, Depletion and Amortization	$ 124,274	$ 43,463	$ 17,313	$ 53,253	$ 275	$ 238,578	$ 1,627	$ 756	$ 240,961
Income Tax Expense (Benefit)	$ (41,962)	$ 17,806	$ (17,677)	$ 15,258	$ 632	$ (25,943)	$ 1,493	$ 16,956	$ (7,494)
Segment Profit: Net Income (Loss)	$ 180,632	$ 97,246	$ 83,519	$ 51,217	$ 373	$ 412,987	$ (112)	$ (21,354)	$ 391,521
Expenditures for Additions to Long-Lived Assets	$ 380,677	$ 92,832	$ 61,728	$ 85,648	$ 40	$ 620,925	$ 1	$ (20,324)	$ 600,602
	At September 30, 2018								
	(Thousands)								
Segment Assets	$ 1,568,563	$1,848,180	$ 533,608	$1,921,971	$ 50,971	$ 5,923,293	$78,109	$ 35,084	$ 6,036,486

	Year Ended September 30, 2017								
	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Elimination	Total Consolidated
	(Thousands)								
Revenue from External Customers(1)	$ 614,599	$ 206,615	$ 115	$ 626,899	$ 128,586	$ 1,576,814	$ 2,173	$ 894	$ 1,579,881
Intersegment Revenues	$ —	$ 87,810	$ 107,566	$ 13,072	$ 794	$ 209,242	$ —	$ (209,242)	$ —
Interest Income	$ 707	$ 1,467	$ 994	$ 1,051	$ 571	$ 4,790	$ 213	$ (890)	$ 4,113
Interest Expense	$ 53,702	$ 33,717	$ 9,142	$ 28,492	$ 47	$ 125,100	$ —	$ (5,263)	$ 119,837
Depreciation, Depletion and Amortization	$ 112,565	$ 41,196	$ 16,162	$ 52,582	$ 279	$ 222,784	$ 661	$ 750	$ 224,195
Income Tax Expense (Benefit)	$ 66,093	$ 40,947	$ 29,694	$ 24,894	$ 891	$ 162,519	$ (247)	$ (1,590)	$ 160,682
Segment Profit: Net Income (Loss)	$ 129,326	$ 68,446	$ 40,377	$ 46,935	$ 1,509	$ 286,593	$ (342)	$ (2,769)	$ 283,482
Expenditures for Additions to Long-Lived Assets	$ 253,057	$ 95,336	$ 32,645	$ 80,867	$ 36	$ 461,941	$ 39	$ 137	$ 462,117
	At September 30, 2017								
	(Thousands)								
Segment Assets	$ 1,407,152	$1,929,788	$ 580,051	$2,013,123	$ 60,937	$ 5,991,051	$76,861	$ 35,408	$ 6,103,320

	Year Ended September 30, 2016								
	Exploration and Production	Pipeline and Storage	Gathering	Utility	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)								
Revenue from External Customers(1)	$ 607,113	$ 215,674	$ 374	$ 531,024	$ 93,578	$ 1,447,763	$ 3,753	$ 900	$ 1,452,416
Intersegment Revenues	$ —	$ 90,755	$ 89,073	$ 13,123	$ 884	$ 193,835	$ —	$ (193,835)	$ —
Interest Income	$ 858	$ 770	$ 297	$ 1,737	$ 422	$ 4,084	$ 117	$ 34	$ 4,235
Interest Expense	$ 55,434	$ 33,327	$ 8,872	$ 27,582	$ 49	$ 125,264	$ —	$ (4,220)	$ 121,044
Depreciation, Depletion and Amortization	$ 139,963	$ 43,273	$ 15,282	$ 48,618	$ 278	$ 247,414	$ 1,260	$ 743	$ 249,417
Income Tax Expense (Benefit)	$ (334,029)	$ 50,241	$ 24,334	$ 25,602	$ 2,460	$ (231,392)	$ 561	$ (1,718)	$ (232,549)
Significant Non-Cash Item: Impairment of Oil and Gas Producing Properties	$ 948,307	$ —	$ —	$ —	$ —	$ 948,307	$ —	$ —	$ 948,307
Segment Profit: Net Income (Loss)	$ (452,842)	$ 76,610	$ 30,499	$ 50,960	$ 4,348	$ (290,425)	$ 778	$ (1,311)	$ (290,958)
Expenditures for Additions to Long-Lived Assets	$ 256,104	$ 114,250	$ 54,293	$ 98,007	$ 34	$ 522,688	$ 37	$ 326	$ 523,051
	At September 30, 2016								
	(Thousands)								
Segment Assets	$ 1,323,081	$1,680,734	$ 534,259	$2,021,514	$ 63,392	$ 5,622,980	$77,138	$ (63,731)	$ 5,636,387

(1) All Revenue from External Customers originated in the United States.

Geographic Information	At September 30		
	2018	2017	2016
		(Thousands)	
Long-Lived Assets:			
United States	$ 5,491,895	$ 5,285,040	$ 5,223,356

Note K — Quarterly Financial Data (unaudited)

In the opinion of management, the following quarterly information includes all adjustments necessary for a fair statement of the results of operations for such periods. Per common share amounts are calculated using the weighted average number of shares outstanding during each quarter. The total of all quarters may differ from the per common share amounts shown on the Consolidated Statements of Income. Those per common share amounts are based on the weighted average number of shares outstanding for the entire fiscal year. Because of the seasonal nature of the Company's heating business, there are substantial variations in operations reported on a quarterly basis.

Quarter Ended	Operating Revenues	Operating Income	Net Income Available for Common Stock		Earnings per Common Share Basic	Earnings per Common Share Diluted
	(Thousands, except per common share amounts)					
2018						
9/30/2018	$ 289,196	$ 80,629	$ 37,995	(1)	$ 0.44	$ 0.44
6/30/2018	$ 342,912	$ 107,760	$ 63,025		$ 0.73	$ 0.73
3/31/2018	$ 540,905	$ 156,702	$ 91,847	(2)	$ 1.07	$ 1.06
12/31/2017	$ 419,655	$ 141,995	$ 198,654	(3)	$ 2.32	$ 2.30
2017						
9/30/2017	$ 286,937	$ 87,395	$ 45,577		$ 0.53	$ 0.53
6/30/2017	$ 348,369	$ 123,354	$ 59,714		$ 0.70	$ 0.69
3/31/2017	$ 522,075	$ 169,957	$ 89,283		$ 1.05	$ 1.04
12/31/2016	$ 422,500	$ 172,139	$ 88,908		$ 1.04	$ 1.04

(1) Includes a $3.5 million increase to income tax expense associated with the remeasurement of accumulated deferred income taxes in accordance with the 2017 Tax Reform Act.

(2) Includes a $4.0 million increase to income tax expense associated with the remeasurement of accumulated deferred income taxes in accordance with the 2017 Tax Reform Act.

(3) Includes a $111.0 million reduction to income tax expense associated with the remeasurement of accumulated deferred income taxes in accordance with the 2017 Tax Reform Act.

Note L — Supplementary Information for Oil and Gas Producing Activities (unaudited, except for Capitalized Costs Relating to Oil and Gas Producing Activities)

The Company follows authoritative guidance related to oil and gas exploration and production activities that aligns the reserve estimation and disclosure requirements with the requirements of the SEC Modernization of Oil and Gas Reporting rule, which the Company also follows. The SEC rules require companies to value their year-end reserves using 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 following supplementary information is presented in accordance with the authoritative guidance regarding disclosures about oil and gas producing activities and related SEC accounting rules. All monetary amounts are expressed in U.S. dollars.

Capitalized Costs Relating to Oil and Gas Producing Activities

	At September 30	
	2018	2017
	(Thousands)	
Proved Properties(1)	$ 5,114,753	$ 4,832,301
Unproved Properties	62,234	80,932
	5,176,987	4,913,233
Less — Accumulated Depreciation, Depletion and Amortization	3,862,687	3,765,710
	$ 1,314,300	$ 1,147,523

(1) Includes asset retirement costs of $44.3 million and $54.4 million at September 30, 2018 and 2017, respectively.

Costs related to unproved properties are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. 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. Although the timing of the ultimate evaluation or disposition of the unproved properties cannot be determined, the Company expects the majority of its acquisition costs associated with unproved properties to be transferred into the amortization base by 2023. It expects the majority of its development and exploration costs associated with unproved properties to be transferred into the amortization base by 2020. Following is a summary of costs excluded from amortization at September 30, 2018:

	Total as of September 30, 2018	Year Costs Incurred			
		2018	2017	2016	Prior
	(Thousands)				
Acquisition Costs	$ 39,681	$ —	$ —	$ —	$ 39,681
Development Costs	14,824	11,115	236	2,886	587
Exploration Costs	7,606	—	32	7,574	—
Capitalized Interest	123	20	—	103	—
	$ 62,234	$ 11,135	$ 268	$ 10,563	$ 40,268

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities

	Year Ended September 30		
	2018	2017	2016
		(Thousands)	
United States			
Property Acquisition Costs:			
Proved	$ 1,544	$ 8,908	$ 1,342
Unproved	4,286	262	2,165
Exploration Costs(1)	29,365	40,975	27,561
Development Costs(2)	332,496	200,639	219,386
Asset Retirement Costs	(10,107)	(9,175)	(49,653)
	$ 357,584	$ 241,609	$ 200,801

(1) Amounts for 2018, 2017 and 2016 include capitalized interest of zero, $0.3 million and $0.3 million, respectively.
(2) Amounts for 2018, 2017 and 2016 include capitalized interest of $0.3 million, $0.2 million and $0.2 million, respectively.

For the years ended September 30, 2018, 2017 and 2016, the Company spent $182.3 million, $101.1 million and $92.8 million, respectively, developing proved undeveloped reserves.

Results of Operations for Producing Activities

	Year Ended September 30		
	2018	2017	2016
United States		(Thousands, except per Mcfe amounts)	
Operating Revenues:			
Natural Gas (includes transfers to operations of $2,134, $2,357 and $1,765, respectively)(1)	$ 390,642	$ 399,975	$ 282,619
Oil, Condensate and Other Liquids	168,254	126,517	103,533
Total Operating Revenues(2)	558,896	526,492	386,152
Production/Lifting Costs	162,721	165,991	153,914
Franchise/Ad Valorem Taxes	14,355	15,372	13,794
Purchased Emission Allowance Expense	1,883	1,391	700
Accretion Expense	4,266	4,896	6,663
Depreciation, Depletion and Amortization ($0.67, $0.63 and $0.85 per Mcfe of production, respectively)	119,946	108,471	136,579
Impairment of Oil and Gas Producing Properties	—	—	948,307
Income Tax Expense (Benefit)	72,723	86,657	(368,940)
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	$ 183,002	$ 143,714	$ (504,865)

(1) There were no revenues from sales to affiliates for all years presented.
(2) Exclusive of hedging gains and losses. See further discussion in Note G — Financial Instruments.

Reserve Quantity Information

The Company's proved oil and gas reserve estimates are prepared by the Company's reservoir engineers who meet the qualifications of Reserve Estimator per the "Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserve Information" promulgated by the Society of Petroleum Engineers as of February 19, 2007. The Company maintains comprehensive internal reserve guidelines and a continuing education program designed to keep its staff up to date with current SEC regulations and guidance.

The Company's Vice President of Reservoir Engineering is the primary technical person responsible for overseeing the Company's reserve estimation process and engaging and overseeing the third party reserve audit. His qualifications include a Bachelor of Science Degree in Petroleum Engineering and over 30 years of Petroleum Engineering experience with both major and independent oil and gas companies. He has maintained oversight of the Company's reserve estimation process since 2003. He is a member of the Society of Petroleum Evaluation Engineers and a Registered Professional Engineer in the State of Texas.

The Company maintains a system of internal controls over the reserve estimation process. Management reviews the price, heat content, lease operating cost and future investment assumptions used in the economic model to determine the reserves. The Vice President of Reservoir Engineering reviews and approves all new reserve assignments and significant reserve revisions. Access to the reserve database is restricted. Significant changes to the reserve report are reviewed by senior management on a quarterly basis. Periodically, the Company's internal audit department assesses the design of these controls and performs testing to determine the effectiveness of such controls.

All of the Company's reserve estimates are audited annually by Netherland, Sewell and Associates, Inc. (NSAI). Since 1961, NSAI has evaluated gas and oil properties and independently certified petroleum reserve quantities in the United States and internationally under the Texas Board of Professional Engineers Registration No. F-002699. The primary technical persons (employed by NSAI) that are responsible for leading the audit include a professional engineer registered with the State of Texas (consulting at NSAI since 2004 and with over 5 years of prior industry experience in petroleum engineering) and a professional geoscientist registered in the State of Texas (consulting at NSAI since 2008 and with over 11 years of prior industry experience in petroleum geosciences). NSAI was satisfied with the methods and procedures used by the Company to prepare its reserve estimates at September 30, 2018 and did not identify any problems which would cause it to take exception to those estimates.

The reliable technologies that were utilized in estimating the reserves include wire line open-hole log data, performance data, log cross sections, core data, 2D and 3D seismic data and statistical analysis. The statistical method utilized production performance from both the Company's and competitors' wells. Geophysical data includes data from the Company's wells, published documents and state data-sites, and 2D and 3D seismic data. These were used to confirm continuity of the formation.

	Gas MMcf			
	U.S.			
	Appalachian Region		West Coast Region	Total Company
Proved Developed and Undeveloped Reserves:				
September 30, 2015	2,092,782		49,346	2,142,128
Extensions and Discoveries	185,347	(1)	—	185,347
Revisions of Previous Estimates	(245,029)		(3,132)	(248,161)
Production	(140,457)	(2)	(3,090)	(143,547)
Sale of Minerals in Place	(261,192)		—	(261,192)
September 30, 2016	1,631,451		43,124	1,674,575
Extensions and Discoveries	386,649	(1)	8	386,657
Revisions of Previous Estimates	84,480		6,369	90,849
Production	(154,093)	(2)	(2,995)	(157,088)
Sale of Minerals in Place	(21,873)		—	(21,873)
September 30, 2017	1,926,614		46,506	1,973,120
Extensions and Discoveries	521,694	(1)	—	521,694
Revisions of Previous Estimates	90,113		3,322	93,435
Production	(160,499)	(2)	(2,407)	(162,906)
Sale of Minerals in Place	(57,420)		(10,581)	(68,001)
September 30, 2018	2,320,502		36,840	2,357,342
Proved Developed Reserves:				
September 30, 2015	1,267,498		49,346	1,316,844
September 30, 2016	1,089,492		43,124	1,132,616
September 30, 2017	1,316,596		46,506	1,363,102
September 30, 2018	1,569,692		36,840	1,606,532
Proved Undeveloped Reserves:				
September 30, 2015	825,284		—	825,284
September 30, 2016	541,959		—	541,959
September 30, 2017	610,018		—	610,018
September 30, 2018	750,810		—	750,810

(1) Extensions and discoveries include 179 Bcf (during 2016), 181 Bcf (during 2017) and 274 Bcf (during 2018), of Marcellus Shale gas in the Appalachian region. Extensions and discoveries include 6 Bcf (during 2016), 205 Bcf (during 2017) and 248 Bcf (during 2018), of Utica Shale gas in the Appalachian region.

(2) Production includes 135,598 MMcf (during 2016), 145,452 MMcf (during 2017) and 150,196 MMcf (during 2018), from Marcellus Shale fields (which exceed 15% of total reserves). Production includes 9,409 MMcf (during 2018), from Utica Shale fields (which exceed 15% of total reserves).

	Oil Mbbl		
	U.S.		
	Appalachian Region	West Coast Region	Total Company
Proved Developed and Undeveloped Reserves:			
September 30, 2015	220	33,502	33,722
Extensions and Discoveries	—	530	530
Revisions of Previous Estimates	(46)	(2,201)	(2,247)
Production	(28)	(2,895)	(2,923)
Sales of Minerals in Place	(73)	—	(73)
September 30, 2016	73	28,936	29,009
Extensions and Discoveries	—	674	674
Revisions of Previous Estimates	(12)	3,305	3,293
Production	(4)	(2,736)	(2,740)
Sales of Minerals in Place	(29)	—	(29)
September 30, 2017	28	30,179	30,207
Extensions and Discoveries	—	2,301	2,301
Revisions of Previous Estimates	(10)	2,487	2,477
Production	(4)	(2,531)	(2,535)
Sales of Minerals in Place	—	(4,787)	(4,787)
September 30, 2018	14	27,649	27,663
Proved Developed Reserves:			
September 30, 2015	220	33,150	33,370
September 30, 2016	73	28,698	28,771
September 30, 2017	28	29,771	29,799
September 30, 2018	14	26,689	26,703
Proved Undeveloped Reserves:			
September 30, 2015	—	352	352
September 30, 2016	—	238	238
September 30, 2017	—	408	408
September 30, 2018	—	960	960

The Company's proved undeveloped (PUD) reserves increased from 612 Bcfe at September 30, 2017 to 757 Bcfe at September 30, 2018. PUD reserves in the Marcellus Shale decreased from 456 Bcfe at September 30, 2017 to 394 Bcfe at September 30, 2018. PUD reserves in the Utica Shale increased from 154 Bcfe at September 30, 2017 to 357 Bcfe at September 30, 2018. The Company's total PUD reserves were 30% of total proved reserves at September 30, 2018, up from 28% of total proved reserves at September 30, 2017.

The Company's PUD reserves increased from 543 Bcfe at September 30, 2016 to 612 Bcfe at September 30, 2017. PUD reserves in the Marcellus Shale decreased from 542 Bcfe at September 30, 2016 to 456 Bcfe at September 30, 2017. The Company's total PUD reserves were 28% of total proved reserves at September 30, 2017, down from 29% of total proved reserves at September 30, 2016.

The increase in PUD reserves in 2018 of 145 Bcfe is a result of 431 Bcfe in new PUD reserve additions (229 Bcfe from the Marcellus Shale, 197 Bcfe from the Utica Shale and 5 Bcfe from the West Coast region) and 60 Bcfe in upward revisions to remaining PUD reserves, partially offset by 284 Bcfe in PUD conversions to developed reserves (264 Bcfe from the Marcellus Shale, 18 Bcfe from the Utica Shale and 2 Bcfe from the West Coast region), 5 Bcfe in PUD reserves removed for one Marcellus PUD and sales of 57 Bcfe in PUD working interest reserves sold as part of the joint development agreement, previously discussed.

The increase in PUD reserves in 2017 of 69 Bcfe was a result of 269 Bcfe in new PUD reserve additions (113 Bcfe from the Marcellus Shale, 154 Bcfe from the Utica Shale and 2 Bcfe from the West Coast region) and 13 Bcfe in upward revisions to remaining PUD reserves, partially offset by 159 Bcfe in PUD conversions to developed reserves (158 Bcfe from the Marcellus Shale and 1 Bcfe from the West Coast region) and 54 Bcfe in PUD reserves removed. In the Eastern Development Area, Marcellus Shale PUD reserves of 36 Bcfe were removed due to development timing no longer scheduled to meet the five year requirement for proved reserves. Seneca successfully leased an adjacent tract to these wells in 2017 and intends to develop the wells now with longer laterals drilled into this adjacent tract. These development plans are not expected to commence within the five year time horizon from original booking. Marcellus Shale PUD reserves of 18 Bcfe were removed as part of Seneca’s transition toward a Utica focused development program in the Western Development Area, where certain Marcellus well locations were replaced with Utica well locations in the Company's development plan.

The Company invested $182 million during the year ended September 30, 2018 to convert 284 Bcfe of predominantly Marcellus and Utica Shale PUD reserves to developed reserves. This represents 46% of the net PUD reserves booked at September 30, 2017 (or 51% of remaining net PUD reserves after 57 Bcfe in PUD working interest reserves were sold as part of the joint development agreement, as previously discussed). In fiscal 2018, the Company developed 53 (or 62%) of its well locations with net PUD reserves recorded at September 30, 2017. The vast majority of these wells were in the Appalachian region.

The Company invested $101 million during the year ended September 30, 2017 to convert 147 Bcfe of Marcellus Shale PUD reserves to developed reserves. This represents 27% of the net PUD reserves booked at September 30, 2016. In fiscal 2017, the Company developed 37 (or 41%) of its well locations with net PUD reserves recorded at September 30, 2016. The vast majority of these wells were in the Appalachian region.

In 2019, the Company estimates that it will invest approximately $210 million to develop its PUD reserves. The Company is committed to developing its PUD reserves within five years as required by the SEC’s final rule on Modernization of Oil and Gas Reporting. Since that rule, and over the last five years, the Company developed 51% of its beginning year PUD reserves in fiscal 2014, 33% of its beginning year PUD reserves in fiscal 2015, 25% of its beginning year PUD reserves in fiscal 2016, 27% of its beginning year PUD reserves in fiscal 2017 and 51% of its beginning year PUD reserves in fiscal 2018.

At September 30, 2018, the Company does not have a material concentration of proved undeveloped reserves that have been on the books for more than five years at the corporate level, country level or field level. All of the Company’s proved reserves are in the United States.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The Company cautions that the following presentation of the standardized measure of discounted future net cash flows is intended to be neither a measure of the fair market value of the Company’s oil and gas properties, nor an estimate of the present value of actual future cash flows to be obtained as a result of their development and production. It is based upon subjective estimates of proved reserves only and attributes no value to categories of reserves other than proved reserves, such as probable or possible reserves, or to unproved acreage. Furthermore, in accordance with the SEC’s final rule on Modernization of Oil and Gas Reporting, it is based on the 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 and costs adjusted only for existing contractual changes. It assumes an arbitrary discount rate of 10%. Thus, it gives no effect to future price and cost changes certain to occur under widely fluctuating political and economic conditions.

The standardized measure is intended instead to provide a means for comparing the value of the Company's proved reserves at a given time with those of other oil- and gas-producing companies than is provided by a simple comparison of raw proved reserve quantities.

	Year Ended September 30		
	2018	2017	2016
		(Thousands)	
United States			
Future Cash Inflows	$ 7,822,855	$ 6,144,317	$ 3,768,463
Less:			
Future Production Costs	2,606,411	2,378,262	1,994,916
Future Development Costs	559,707	411,578	375,152
Future Income Tax Expense at Applicable Statutory Rate	1,125,910	1,160,469	303,397
Future Net Cash Flows	3,530,827	2,194,008	1,094,998
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	1,810,522	1,080,962	452,470
Standardized Measure of Discounted Future Net Cash Flows	$ 1,720,305	$ 1,113,046	$ 642,528

The principal sources of change in the standardized measure of discounted future net cash flows were as follows:

	Year Ended September 30		
	2018	2017	2016
		(Thousands)	
United States			
Standardized Measure of Discounted Future			
Net Cash Flows at Beginning of Year	$ 1,113,046	$ 642,528	$ 1,323,034
Sales, Net of Production Costs	(381,775)	(345,075)	(218,444)
Net Changes in Prices, Net of Production Costs	541,021	828,187	(1,066,593)
Extensions and Discoveries	212,494	170,500	47,742
Changes in Estimated Future Development Costs	(43,771)	8,816	143,752
Sales of Minerals in Place	(100,816)	(9,849)	(95,849)
Previously Estimated Development Costs Incurred	182,348	101,134	92,840
Net Change in Income Taxes at Applicable Statutory Rate	55,558	(393,353)	387,739
Revisions of Previous Quantity Estimates	61,363	39,078	6,202
Accretion of Discount and Other	80,837	71,080	22,105
Standardized Measure of Discounted Future Net Cash Flows at End of Year	$ 1,720,305	$ 1,113,046	$ 642,528

Schedule II — Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Additions Charged to Other Accounts(1)	Deductions (2)	Balance at End of Period
Year Ended September 30, 2018					
Allowance for Uncollectible Accounts	$ 22,526	$ 10,905	$ 1,967	$ 10,861	$ 24,537
Valuation Allowance for Deferred Tax Assets (3)	$ —	$ 5,000	$ —	$ —	$ 5,000
Year Ended September 30, 2017					
Allowance for Uncollectible Accounts	$ 21,109	$ 6,301	$ 1,774	$ 6,658	$ 22,526
Year Ended September 30, 2016					
Allowance for Uncollectible Accounts	$ 29,029	$ 6,819	$ 1,521	$ 16,260	$ 21,109

(1) Represents the discount on accounts receivable purchased in accordance with the Utility segment's 2005 New York rate agreement.

(2) Amounts represent net accounts receivable written-off.

(3) Valuation allowance recorded to reflect the potential sequestration of estimated alternative minimum tax credit refunds as a result of the 2017 Tax Reform Act.

Item 9 *Changes in and Disagreements with Accountants on Accounting and Financial Disclosure*

None.

Item 9A *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 September 30, 2018.

Management's Annual Report on Internal Control over Financial Reporting

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act. The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and preparation of financial statements for external purposes in accordance with GAAP. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of September 30, 2018. In making this assessment, management used the framework and criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework,* published in 2013. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of September 30, 2018.

PricewaterhouseCoopers LLP, the independent registered public accounting firm that audited the Company's consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of September 30, 2018. The report appears in Part II, Item 8 of this Annual Report on Form 10-K.

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 September 30, 2018 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B *Other Information*

None.

PART III

Item 10 *Directors, Executive Officers and Corporate Governance*

The information concerning directors will be set forth in the definitive Proxy Statement under the headings entitled "Nominees for Election as Directors for Three-Year Terms to Expire in 2022," "Directors Whose Terms Expire in 2021," "Directors Whose Terms Expire in 2020," and "Section 16(a) Beneficial Ownership Reporting Compliance" and is incorporated herein by reference. The information concerning corporate governance will be set forth in the definitive Proxy Statement under the heading entitled "Meetings of the Board of Directors and Standing Committees" and is incorporated herein by reference. Information concerning the Company's executive officers can be found in Part I, Item 1, of this report.

The Company has adopted a Code of Business Conduct and Ethics that applies to the Company's directors, officers and employees and has posted such Code of Business Conduct and Ethics on the Company's website, www.nationalfuelgas.com, together with certain other corporate governance documents. Copies of the Company's Code of Business Conduct and Ethics, charters of important committees, and Corporate Governance Guidelines will be made available free of charge upon written request to Investor Relations, National Fuel Gas Company, 6363 Main Street, Williamsville, New York 14221.

The Company intends to satisfy the disclosure requirement under Item 5.05 of Form 8-K regarding an amendment to, or a waiver from, a provision of its code of ethics that applies to the Company's principal executive officer, principal financial officer, principal accounting officer or controller, or persons performing similar functions, and that relates to any element of the code of ethics definition enumerated in paragraph (b) of Item 406 of the SEC's Regulation S-K, by posting such information on its website, www.nationalfuelgas.com.

Item 11 *Executive Compensation*

The information concerning executive compensation will be set forth in the definitive Proxy Statement under the headings "Executive Compensation" and "Compensation Committee Interlocks and Insider Participation" and, excepting the "Report of the Compensation Committee," is incorporated herein by reference.

Item 12 *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters*

Equity Compensation Plan Information

The equity compensation plan information will be set forth in the definitive Proxy Statement under the heading "Equity Compensation Plan Information" and is incorporated herein by reference.

Security Ownership and Changes in Control

(a) Security Ownership of Certain Beneficial Owners

The information concerning security ownership of certain beneficial owners will be set forth in the definitive Proxy Statement under the heading "Security Ownership of Certain Beneficial Owners and Management" and is incorporated herein by reference.

(b) Security Ownership of Management

The information concerning security ownership of management will be set forth in the definitive Proxy Statement under the heading "Security Ownership of Certain Beneficial Owners and Management" and is incorporated herein by reference.

(c) Changes in Control

None.

Item 13 *Certain Relationships and Related Transactions, and Director Independence*

The information regarding certain relationships and related transactions will be set forth in the definitive Proxy Statement under the headings "Compensation Committee Interlocks and Insider Participation" and "Related Person Transactions" and is incorporated herein by reference. The information regarding director independence is set forth in the definitive Proxy Statement under the heading "Director Independence" and is incorporated herein by reference.

Item 14 *Principal Accountant Fees and Services*

The information concerning principal accountant fees and services will be set forth in the definitive Proxy Statement under the heading "Audit Fees" and is incorporated herein by reference.

PART IV

Item 15 *Exhibits and Financial Statement Schedules*

(a)1. Financial Statements

Financial statements filed as part of this report are listed in the index included in Item 8 of this Form 10-K, and reference is made thereto.

(a)2. Financial Statement Schedules

Financial statement schedules filed as part of this report are listed in the index included in Item 8 of this Form 10-K, and reference is made thereto.

(a)3. Exhibits

All documents referenced below were filed pursuant to the Securities Exchange Act of 1934 by National Fuel Gas Company (File No. 1-3880), unless otherwise noted.

Exhibit Number	Description of Exhibits
3(i)	Articles of Incorporation:
•	Restated Certificate of Incorporation of National Fuel Gas Company dated September 21, 1998; Certificate of Amendment of Restated Certificate of Incorporation dated March 14, 2005 (Exhibit 3.1, Form 10-K for fiscal year ended September 30, 2012)

Exhibit Number	Description of Exhibits
3(ii)	By-Laws:
•	National Fuel Gas Company By-Laws as amended March 10, 2016 (Exhibit 3.1, Form 8-K dated March 16, 2016)
4	Instruments Defining the Rights of Security Holders, Including Indentures:
•	Indenture, dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 2(b) in File No. 2-51796)
•	Third Supplemental Indenture, dated as of December 1, 1982, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(a)(4) in File No. 33-49401)
•	Eleventh Supplemental Indenture, dated as of May 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(b), Form 8-K dated February 14, 1992)
•	Twelfth Supplemental Indenture, dated as of June 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(c), Form 8-K dated June 18, 1992)
•	Thirteenth Supplemental Indenture, dated as of March 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(a)(14) in File No. 33-49401)
•	Fourteenth Supplemental Indenture, dated as of July 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1993)
•	Indenture dated as of October 1, 1999, between the Company and The Bank of New York Mellon (formerly The Bank of New York) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1999)
•	Officer's Certificate establishing 8.75% Notes due 2019, dated April 6, 2009 (Exhibit 4.4, Form 8-K dated April 6, 2009)
•	Officer's Certificate establishing 4.90% Notes due 2021, dated December 1, 2011 (Exhibit 4.4, Form 8-K dated December 1, 2011)
•	Officers Certificate establishing 3.75% Notes due 2023, dated February 15, 2023 (Exhibit 4.1.1, Form 8-K dated February 15, 2013)
•	Officers Certificate establishing 5.20% Notes due 2025, dated June 25, 2015 (Exhibit 4.1.1, Form 8-K dated June 25, 2015)
•	Officers Certificate establishing 3.95% Notes due 2027, dated September 27, 2017 (Exhibit 4.1.1, Form 8-K dated September 27, 2017)
•	Officers Certificate establishing 4.75% Notes due 2028, dated August 17, 2018 (Exhibit 4.1.1, Form 8-K dated August 17, 2018)
•	Amended and Restated Rights Agreement, dated as of December 4, 2008, between the Company and The Bank of New York Mellon (formerly The Bank of New York), as rights agent (Exhibit 4.1, Form 8-K dated December 4, 2008)
•	Letter of Appointment of Wells Fargo Bank, National Association, as Successor Rights Agent, dated July 18, 2012 (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 2012)

Exhibit Number	Description of Exhibits
•	Amendment No. 1, dated as of January 11, 2018, to the Amended and Restated Rights Agreement, dated as of December 4, 2008, between National Fuel Gas Company and Wells Fargo Bank, National Association, as successor rights agent (Exhibit 4.1, Form 8-K dated January 12, 2018)
10	Material Contracts:
•	Fourth Amended and Restated Credit Agreement, dated as of October 25, 2018, among the Company, the Lenders Party Thereto, and JP Morgan Chase Bank, National Association, as Administrative Agent (Exhibit 10.1, Form 8-K dated October 31, 2018)
•	Third Amended and Restated Credit Agreement, dated as of September 9, 2016, among the Company, the Lenders Party Thereto, and JP Morgan Chase Bank, National Association, as Administrative Agent (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2016)
•	Form of Indemnification Agreement, dated September 2006, between the Company and each Director (Exhibit 10.1, Form 8-K dated September 18, 2006)
	Management Contracts and Compensatory Plans and Arrangements:
•	Standard Form of Amended and Restated Employment Continuation and Noncompetition Agreement among the Company, a subsidiary of the Company and executive officers (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2008)
•	Form of Amended and Restated Employment Continuation and Noncompetition Agreement between Seneca Resources Company, LLC and John P. McGinnis (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2017)
•	National Fuel Gas Company 1997 Award and Option Plan, as amended and restated as of July 23, 2007 (Exhibit 10.4, Form 10-Q for the quarterly period ended March 31, 2008)
•	Form of Stock Appreciation Right Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2008)
•	Form of Stock Appreciation Right Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2011)
•	National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 8-K dated March 16, 2015)
•	Form of Stock Appreciation Right Award Notice under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2010)
•	Form of Stock Appreciation Right Award Notice under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.4, Form 10-Q for the quarterly period ended December 31, 2010)
•	National Fuel Gas Company 2012 Annual At Risk Compensation Incentive Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2012)
•	National Fuel Gas Company Executive Annual Cash Incentive Program (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2009)
•	Administrative Rules of the Compensation Committee of the Board of Directors of National Fuel Gas Company, as amended and restated effective June 9, 2016 (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2016)
•	National Fuel Gas Company Deferred Compensation Plan, as amended and restated through March 20, 1997 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1997)

Exhibit Number	Description of Exhibits
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 16, 1997 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 1997)
•	Amendment No. 2 to the National Fuel Gas Company Deferred Compensation Plan, dated March 13, 1998 (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 1998)
•	Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated February 18, 1999 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 1999)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 15, 2001 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 2001)
•	Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated October 21, 2005 (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 2005)
•	Form of Letter Regarding Tophat Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 2005)
•	National Fuel Gas Company Tophat Plan, as amended September 20, 2007 (Exhibit 10.3, Form 10-K for the fiscal year ended September 30, 2007)
•	Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and David F. Smith (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1999)
•	Amendment Number 1 to Split Dollar Insurance and Death Benefit Agreement by and between the Company and David F. Smith, dated March 29, 1999 (Exhibit 10.14, Form 10-K for fiscal year ended September 30, 1999)
•	National Fuel Gas Company Parameters for Executive Life Insurance Plan (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2004)
•	National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of September 24, 2008 (Exhibit 10.5, Form 10-K for the fiscal year ended September 30, 2008)
•	Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated June 1, 2010 (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2010)
•	Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated August 13, 2015 (Exhibit 10.2, Form 10-K for the fiscal year ended September 30, 2015)
•	National Fuel Gas Company 2009 Non-Employee Director Equity Compensation Plan, as amended and reapproved March 10, 2016 (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2016)
•	Form of Award Notice for Return on Capital Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2017)
•	Form of Award Notice for Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2017)
•	Form of Award Notice for Restricted Stock Units under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2017)
•	Form of Award Notice for Return on Capital Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2016)

Exhibit Number	Description of Exhibits
•	Form of Award Notice for Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2016)
•	Form of Award Notice for Restricted Stock Units under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2016)
•	Form of Award Notice for Return on Capital Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2015)
•	Form of Award Notice for Total Shareholder Return Performance Shares under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2015)
•	Form of Award Notice for Restricted Stock Units under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2015)
21	Subsidiaries of the Registrant
23	Consents of Experts:
23.1	Consent of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Company, LLC
23.2	Consent of Independent Registered Public Accounting Firm
31	Rule 13a-14(a)/15d-14(a) Certifications:
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	Additional Exhibits:
99.1	Report of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Company, LLC
99.2	Company Maps
101	Interactive data files submitted pursuant to Regulation S-T: (i) the Consolidated Statements of Income and Earnings Reinvested in the Business for the years ended September 30, 2018, 2017 and 2016, (ii) the Consolidated Statements of Comprehensive Income for the years ended September 30, 2018, 2017 and 2016 (iii) the Consolidated Balance Sheets at September 30, 2018 and September 30, 2017, (iv) the Consolidated Statements of Cash Flows for the years ended September 30, 2018, 2017 and 2016 and (v) the Notes to Consolidated Financial Statements.

• Incorporated herein by reference as indicated.

All other exhibits are omitted because they are not applicable or the required information is shown elsewhere in this Annual Report on Form 10-K.

•• 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.

Signatures

Pursuant to the requirements of Section 13 or 15(d) 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)

By /s/ R. J. Tanski
R. J. Tanski
President and Chief Executive Officer

Date: November 16, 2018

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	
/s/ D. F. Smith D. F. Smith	Chairman of the Board and Director	Date: November 16, 2018
/s/ P. C. Ackerman P. C. Ackerman	Director	Date: November 16, 2018
/s/ D. C. Carroll D. C. Carroll	Director	Date: November 16, 2018
/s/ S. E. Ewing S. E. Ewing	Director	Date: November 16, 2018
/s/ S. C. Finch S.C. Finch	Director	Date: November 16, 2018
/s/ J. N. Jaggers J. N. Jaggers	Director	Date: November 16, 2018
/s/ R. Ranich R. Ranich	Director	Date: November 16, 2018
/s/ J. W. Shaw J. W. Shaw	Director	Date: November 16, 2018
/s/ T. E. Skains T. E. Skains	Director	Date: November 16, 2018
/s/ R. J. Tanski R. J. Tanski	President, Chief Executive Officer and Director	Date: November 16, 2018
/s/ D. P. Bauer D. P. Bauer	Treasurer and Principal Financial Officer	Date: November 16, 2018
/s/ K. M. Camiolo K. M. Camiolo	Controller and Principal Accounting Officer	Date: November 16, 2018