NATIONAL FUEL GAS CO
Form 10-K
November 22, 2013
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UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

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

For the Fiscal Year Ended September 30, 2013

¨ **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 þ 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 þ

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

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

Indicate by check mark 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. þ

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

Large accelerated filer þ	Accelerated filer ¨	Non-accelerated filer ¨	Smaller reporting company ¨
		(Do not check if a smaller reporting company)	

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

The aggregate market value of the voting stock held by nonaffiliates of the registrant amounted to $4,953,650,000 as of March 31, 2013.

Common Stock, par value $1.00 per share, outstanding as of October 31, 2013: 83,692,481 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant s definitive Proxy Statement for its 2014 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission within 120 days of September 30, 2013, are incorporated by reference into Part III of this report.

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Glossary of Terms

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

National Fuel Gas Companies

Company The Registrant, the Registrant and its subsidiaries or the Registrant s subsidiaries as appropriate in the context of the disclosure

Distribution Corporation National Fuel Gas Distribution Corporation

Empire Empire Pipeline, Inc.

ESNE Energy Systems North East, LLC

Highland Highland Forest Resources, Inc.

Horizon LFG Horizon LFG, Inc.

Horizon Power Horizon Power, Inc.

Midstream Corporation National Fuel Gas Midstream Corporation

Model City Model City Energy, LLC

National Fuel National Fuel Gas Company

NFR National Fuel Resources, Inc.

Registrant National Fuel Gas Company

Seneca Seneca Resources Corporation

Seneca Energy Seneca Energy II, LLC

Supply Corporation National Fuel Gas Supply Corporation

Regulatory Agencies

CFTC Commodity Futures Trading Commission

EPA United States Environmental Protection Agency

FASB Financial Accounting Standards Board

FERC Federal Energy Regulatory Commission

NYDEC New York State Department of Environmental Conservation

NYPSC State of New York Public Service Commission

PaDEP Pennsylvania Department of Environmental Protection

PaPUC Pennsylvania Public Utility Commission

PHMSA Pipeline and Hazardous Materials Safety Administration

SEC Securities and Exchange Commission

Other

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.

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

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.

Order No. 636 An order issued by FERC that required interstate pipelines to separate their sales and transportation services and to provide equal, open-access transportation regardless of where the gas is purchased.

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.

VEBA Voluntary Employees Beneficiary Association

WNC Weather normalization clause; a clause in utility rates which adjusts customer rates to allow a utility to recover its normal operating costs calculated at normal temperatures. If temperatures during the measured period are warmer than normal, customer rates are adjusted upward in order to recover projected operating costs. If temperatures during the measured period are colder than normal, customer rates are adjusted downward so that only the projected operating costs will be recovered.

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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 and reports financial results for five business segments.

1. 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 735,000 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.

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) 27 underground natural gas storage fields owned and operated by Supply Corporation as well as four other underground natural gas storage fields owned and operated jointly with other interstate gas pipeline companies. Empire, an interstate pipeline company, transports natural gas for Distribution Corporation and for other utilities, large industrial customers and power producers in New York State. Empire owns the Empire Pipeline, a 249-mile integrated pipeline system comprising three principal components: a legacy 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 76-mile pipeline extension from near Rochester, New York to an interconnection with the unaffiliated Millennium Pipeline near Corning, New York (the Empire Connector), and a 16-mile pipeline extension from Corning into Tioga County, Pennsylvania (the Tioga County Extension). The Millennium Pipeline serves the New York City area. The Empire Connector was placed into service on December 10, 2008, and the Tioga County Extension was fully placed into service on November 22, 2011.

3. The Exploration and Production segment operations are carried out by Seneca Resources Corporation (Seneca), a Pennsylvania corporation. Seneca Western Minerals Corp., formerly an indirect, wholly owned subsidiary of Seneca, was merged into Seneca in October 2012. Seneca is engaged in the exploration for, and the development and production of, natural gas and oil reserves in California, in the Appalachian region of the United States, and in Kansas. At September 30, 2013, Seneca had U.S. proved developed and undeveloped reserves of 41,598 Mbbl of oil and 1,299,515 MMcf of natural gas.

4. 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.

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

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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.

The following business is not included in any of the five reported business segments:

- Seneca s Northeast Division, which markets timber from Appalachian land holdings. At September 30, 2013, the Company owned approximately 95,000 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 2013.

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 (including foreign) regulations on various subjects, including environmental matters, to which other companies doing similar business in the same locations are subject.

The Utility Segment

The Utility segment contributed approximately 25.3% of the Company s 2013 net income available for common stock.

Additional discussion of the Utility segment appears below in this Item 1 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 Pipeline and Storage Segment

The Pipeline and Storage segment contributed approximately 24.3% of the Company s 2013 net income available for common stock.

Supply Corporation has service agreements for all of its firm storage capacity, totaling 68,393 MDth. The Utility segment has contracted for 29,743 MDth or 44% of the total firm storage capacity, and the Energy Marketing segment accounts for another 4,810 MDth or 7% of the total firm storage capacity. Nonaffiliated customers have contracted for the remaining 33,840 MDth or 49% of the total firm storage capacity. The majority of Supply Corporation s storage and transportation services are performed under contracts that allow Supply Corporation or the shipper to terminate the contract upon six or twelve months notice effective at the end of the contract term. The contracts also typically include evergreen language designed to allow the contracts to extend year-to-year at the end of the primary term. At the beginning of 2014, 81% of Supply Corporation s total firm storage capacity was committed under contracts that, subject to 2013 shipper or Supply Corporation notifications, could have been terminated effective in 2014. Supply Corporation received storage contract termination notifications in 2013 totaling approximately 4,113 MDth of storage capacity. An additional contract without evergreen provisions, representing 1,171 MDth of storage capacity, will expire March 31, 2014. Supply Corporation expects to remarket all terminating capacity with service beginning April 1, 2014.

Supply Corporation s firm transportation capacity is not a fixed quantity, due to the diverse web-like nature of its pipeline system, and is subject to change as the market identifies different transportation paths and receipt/delivery point combinations. Supply Corporation currently has firm transportation service agreements for approximately 2,578 MDth per day (contracted transportation capacity), compared to 2,175 MDth per day last year. The Utility segment accounts for approximately 1,035 MDth per day or 40% of contracted transportation capacity, and the Energy Marketing and Exploration and Production segments represent another 178 MDth per day or 7% of contracted transportation capacity. The remaining 1,365 MDth or 53% of contracted transportation capacity is subject to firm contracts with nonaffiliated customers.

At the beginning of 2014, 42% of Supply Corporation s contracted transportation capacity was committed under affiliate contracts that were scheduled to expire in 2014 or, subject to 2013 shipper or Supply Corporation notifications, could have been terminated effective in 2014. Based on contract expirations and termination notices received in 2013 for 2014 termination, and taking into account any known contract additions, contracted transportation capacity with affiliates is expected to decrease 2% in 2014. Similarly, 17% of contracted transportation capacity was committed under unaffiliated shipper contracts that were scheduled to expire in 2014 or, subject to 2013 shipper or Supply Corporation notifications, could have been terminated effective in 2014. Based on contract expirations and termination notices received in 2013 for 2014 termination, and taking into account any known contract additions, contracted transportation capacity with unaffiliated shippers is expected to increase 12% in 2014.

At the beginning of 2014, Empire had service agreements in place for firm transportation capacity totaling up to approximately 1,067 MDth per day, compared to 950 MDth per day at the beginning of 2013. The majority of Empire s transportation services are performed under contracts that allow Empire or the shipper to terminate the contract upon six or twelve months notice effective at the end of the contract term. The contracts also typically include evergreen language designed to allow the contracts to extend year-to-year at the end of the primary term. At the beginning of 2014, most of Empire s firm contracted capacity (95%) was contracted as long-term, full-year deals. None of the long-term contracts will expire in 2014. The remainder of Empire s firm contracted capacity (5%) was contracted as seasonal (winter-only), single-year or shorter-term contracts. At the beginning of 2014, the Utility segment accounted for 4% of Empire s firm contracted capacity, with the remaining 96% subject to contracts with nonaffiliated customers.

In recent years, the relatively high price of natural gas supplies available at receipt points on the United States/Canadian border in the Niagara region, together with shifting gas supply dynamics, reduced the amount of firm capacity Supply Corporation and Empire contract from those receipt points. However, Supply Corporation and Empire have been successful in marketing and obtaining long-term firm contracts for transportation capacity designed to move Marcellus Shale production to market. For example, Supply Corporation added 160 MDth per day of contracted incremental transportation associated with its Line N 2011 project in 2012, and 483 MDth per day of contracted incremental transportation associated with its Line N 2012 and Northern Access projects in 2013. In addition, in 2012 Empire placed into service two long-term contracts for firm transportation service associated with its Tioga County Extension project. These two contracts now account for 350 MDth per day of firm contracted capacity. Supply Corporation expects additional Marcellus-driven transportation contracts to commence in 2014.

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.

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The Exploration and Production Segment

The Exploration and Production segment contributed approximately 44.4% of the Company s 2013 net income available for common stock.

Additional discussion of the Exploration and Production segment appears below 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 Energy Marketing Segment

The Energy Marketing segment contributed approximately 1.8% of the Company s 2013 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.

The Gathering Segment

The Gathering segment contributed approximately 5.1% of the Company s 2013 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.

All Other Category and Corporate Operations

The All Other category and Corporate operations incurred a net loss in 2013. The impact of this net loss in relation to the Company s 2013 net income available for common stock was negative 0.9%.

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

Natural gas is the principal raw material for the Utility segment. In 2013, the Utility segment purchased 60.0 Bcf of gas for delivery to its customers. Gas purchased from producers and suppliers in the United States under firm contracts (seasonal and longer) accounted for 43% of these purchases. Purchases of gas on the spot market (contracts for one month or less) accounted for 57% of the Utility segment s 2013 purchases. Purchases from South Jersey Resources Group, LLC (24%), Virginia Power Energy Marketing, Inc. (22%), Southwestern Energy Services Company (12%) and Chevron Natural Gas (11%), accounted for 69% of the Utility s 2013 gas purchases. No other producer or supplier provided the Utility segment with more than 10% of its gas requirements in 2013.

Supply Corporation transports and stores 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. Empire transports 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 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 M Supplementary Information for Oil and Gas Producing Activities.

The Energy Marketing segment depends on an adequate supply of natural gas to deliver to its customers. In 2013, this segment purchased 47.4 Bcf of gas, including 46.9 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.

The Gathering Segment gathers, processes and transports 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.

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 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 22%, 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. Over the longer run it is possible that rate design changes resulting from further customer migration to marketer service could expose utility companies such as Distribution Corporation to stranded costs and revenue erosion in the absence of compensating rate relief.

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, competition continues with fuel oil suppliers.

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 or promote new uses of natural gas or new services, rates and contracts.

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. Most of Supply Corporation s facilities are in or near areas overlying the Marcellus Shale production area in Pennsylvania. Its facilities are also located adjacent to Canada and the northeastern United States and provide part of the traditional link between gas-consuming regions of the eastern United States and gas-producing regions of Canada and the southwestern, southern and other continental regions of the United States. While costlier natural gas pricing at Niagara has decreased the importation and transportation of gas from that receipt point, new productive areas in the Appalachian region related to the development of the Marcellus Shale formation have increased transportation services from that region. Supply Corporation has developed its Northern Access and Line N pipeline expansion projects to receive natural gas produced from the

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Marcellus Shale and transport it to key markets of Canada and the northeastern United States. For further discussion of these projects, refer to Item 7, MD&A under the headings Investing Cash Flow and Rate and Regulatory Matters.

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. As noted above, Empire has constructed the Empire Connector project, which expands its natural gas pipeline and enables Empire to serve new markets in New York and elsewhere in the Northeast. In November 2011, Empire also completed its Tioga County Extension project, which stretches approximately 16 miles south from its existing interconnection with Millennium Pipeline at Corning, New York, into Tioga County, Pennsylvania. Like Supply Corporation s Northern Access project, Empire s Tioga County Extension project is designed to facilitate transportation of Marcellus Shale gas to key markets of Canada and the northeastern United States. For further discussion of this project, refer to Item 7, MD&A under the headings Investing Cash Flow and Rate and Regulatory Matters.

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 certain of 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 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.

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.

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 1,912 full-time employees at September 30, 2013.

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 2017, and agreements covering employees in collective bargaining units in Pennsylvania are scheduled to expire in April 2014 and May 2014. In November 2013, the Company entered into a new agreement with one of the collective bargaining units in Pennsylvania. That agreement will go into effect in April 2014 and expire in April 2018. Also in November 2013, the Company reached a new agreement with the local leadership of another collective bargaining unit in Pennsylvania. If ratified by the members of that collective bargaining unit, the agreement will go into effect in May 2014 and expire in May 2018.

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, 2013(1)

Name and Age (as of November 15, 2013)	Current Company Positions and Other Material Business Experience During Past Five Years
David F. Smith (60)	Executive Chairman of the Board of Directors of the Company since April 2013. Mr. Smith previously served as Chairman of the Board of Directors of the Company from March 2010 through March 2013; Chief Executive Officer of the Company from February 2008 through March 2013; and President of the Company from February 2006 through June 2010.
Ronald J. Tanski (61)	Chief Executive Officer of the Company since April 2013 and President of the Company since July 2010. Mr. Tanski previously served as Chief Operating Officer of the Company from July 2010 through March 2013; Treasurer and Principal Financial Officer of the Company from April 2004 through June 2010; and President of Supply Corporation from July 2008 through June 2010.
Matthew D. Cabell (55)	Senior Vice President of the Company since July 2010 and President of Seneca since December 2006.
Anna Marie Cellino (60)	President of Distribution Corporation since July 2008.
John R. Pustulka (61)	President of Supply Corporation since July 2010. Mr. Pustulka previously served as Senior Vice President of Supply Corporation from July 2001 through June 2010.
David P. Bauer (44)	Treasurer and Principal Financial Officer of the Company since July 2010; Treasurer of Midstream Corporation since April 2013; Treasurer of Supply Corporation since June 2007; Treasurer of Empire since June 2007; and Assistant Treasurer of Distribution Corporation since April 2004.
Karen M. Camiolo (54)	Controller and Principal Accounting Officer of the Company since April 2004; Controller of Midstream Corporation since April 2013; and Controller of Distribution Corporation and Supply Corporation since April 2004.
Carl M. Carlotti (58)	Senior Vice President of Distribution Corporation since January 2008.
Paula M. Ciprich (53)	Secretary of the Company since July 2008; General Counsel of the Company since January 2005; Secretary of Distribution Corporation since July 2008.
Donna L. DeCarolis (54)	Vice President Business Development of the Company since October 2007.
James D. Ramsdell (58)	Senior Vice President and Chief Safety Officer of the Company since May 2011. Mr. Ramsdell previously served as Senior Vice President of Distribution Corporation from July 2001 to May 2011.

(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.

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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 and negatively impact the availability of capital from banks, commercial paper purchasers and other sources.

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 and 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. Any of these events could have a material adverse effect on the Company s results of operations, financial condition and cash flows.

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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 sometimes unpredictable government regulations may increase its costs and limit its revenue growth, which may result in reduced earnings.

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

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

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

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

In New York, aggressive generic statewide programs created under the label of efficiency or conservation continue to generate a sizable utility funding requirement for state agencies that administer those programs. Although utilities are authorized to recover the cost of efficiency and conservation program funding through special rates and surcharges, the resulting upward pressure on customer rates, coupled with increased

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assessments and taxes, could affect future tolerance for traditional utility rate increases, especially if natural gas commodity costs were to increase.

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

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

In the Company s Exploration and Production segment, various aspects of Seneca s operations are subject to regulation by, among others, the EPA, the U.S. Fish and Wildlife Service, the U.S. Forestry Service, the 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 the Oil and Gas Conservation Division of the Kansas Corporation Commission. Administrative proceedings or increased regulation by these or other agencies could lead to operational delays or restrictions and increased expense for Seneca.

The Company s liquidity, and in certain circumstances, its earnings, could be adversely affected by the cost of purchasing natural gas during periods in which natural gas prices are rising significantly.

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. Nevertheless, increases in the cost of purchased gas affect cash flows and can therefore impact the amount or availability of the Company s capital resources. The

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Company has issued commercial paper and used short-term borrowings in the past to temporarily finance storage inventories and purchased gas costs, and although the Company expects to do so in the future, it may not be able to access the markets for such borrowings at attractive interest rates or at all. 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. Due to the nature of the regulatory process, there is a risk of a disallowance of full recovery of these costs during any period in which there has been a substantial upward spike in these costs. Any material disallowance of purchased gas costs could have a material adverse effect on cash flow and earnings. In addition, even when Distribution Corporation is allowed full recovery of these purchased gas costs, during periods when natural gas prices are significantly higher than historical levels, customers may have trouble paying the resulting higher bills, and Distribution Corporation s bad debt expenses may increase and ultimately reduce earnings.

Changes in interest rates may affect the Company s ability to finance capital expenditures and to refinance maturing debt.

The Company s ability to cost-effectively finance capital expenditures and to refinance maturing debt will depend in part upon interest rates. The direction in which interest rates may move is uncertain. Declining interest rates have generally been believed to be favorable to utilities, while rising interest rates are generally believed to be unfavorable, because of the levels of debt that utilities may have outstanding. 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 most of the oil and natural gas that it produces at current market and/or indexed prices rather than through fixed-price contracts, although as discussed below, the Company frequently hedges the price of a significant portion of its future production in 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.

The natural gas the Company produces is priced in local markets where production occurs, and price is therefore affected by local or regional supply and demand factors as well as other local market dynamics such as regional pipeline capacity. The prices the Company receives for its natural gas production 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

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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. Supply Corporation and Empire experienced such a change at the Canada/United States border at the Niagara River, where gas prices increased relative to prices available at Leidy, Pennsylvania. This change in price differential caused shippers to seek alternative lower priced gas supplies and, consequently, alternative transportation routes. Supply Corporation and Empire saw transportation volumes decrease in 2009 and 2010 as a result of this situation, and in some cases, shippers decided not to renew transportation contracts. While much of the impact of lower volumes under existing contracts is 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. As contract renewals decrease, revenues and earnings in the Pipeline and Storage segment may decrease, as they did in 2010 and 2011. Supply Corporation and Empire responded to this changed gas price environment by developing projects designed to reverse the flow on their existing systems, as described elsewhere in this report, including Item 7, MD&A under the heading Investing Cash Flow.

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 policy that the use of commodity derivatives contracts comply with various restrictions 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 includes provisions related to the swaps and over-the-counter derivatives markets. Certain provisions of the Dodd-Frank Act related to derivatives became effective July 16, 2011, but other provisions related to derivatives have or will become effective as federal agencies (including the CFTC, various banking regulators and the SEC) adopt rules to implement the law. Among other things, the Dodd-Frank Act (1) regulates certain participants in the swaps markets, including new entities defined as swap dealers and major swap participants, (2) requires clearing and exchange-trading of certain swaps that the CFTC determines must be cleared, (3) requires reporting and recordkeeping of swaps, and (4) enhances the CFTC s enforcement authority, including the authority to establish position limits on derivatives and increases penalties for violations of the Commodity Exchange Act. For purposes of the Dodd-Frank Act, under rules adopted by the SEC and/or CFTC, the Company believes that it qualifies as a non-financial end user of derivatives, that is, as a non-financial entity that uses derivatives to hedge or mitigate commercial risk. Nevertheless, other rules that are being developed could have a significant impact on the Company. For example, banking regulators have proposed a rule that would require swap dealers and major swap participants subject to their jurisdiction to collect initial and variation margin from counterparties that are non-financial end users, though such swap dealers and major swap participants would have the discretion to set thresholds for posting margin (unsecured credit limits). Regardless of the levels of margin that might be required, concern remains that swap dealers and major swap participants will pass along their increased costs through higher transaction costs and prices, and reductions in thresholds for posting margin. In addition, while the Company expects to be exempt from the Dodd-Frank Act s requirement that swaps be cleared and traded on exchanges or swap execution facilities, the cost of entering into a non-exchange cleared swap that is available as an exchange cleared swap may be greater. The Dodd-Frank Act may also increase costs for derivative recordkeeping, reporting, position limit compliance, and other compliance; cause parties to materially alter the terms of derivative contracts; cause parties to restructure certain derivative contracts; reduce the availability of derivatives to protect against risks that the Company encounters or to optimize assets; reduce the Company s ability to monetize or restructure existing derivative contracts; and increase the Company s exposure to less creditworthy counterparties, all of which could increase the Company s business costs.

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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 12-month average 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 compare the level of its unamortized investment in oil and natural gas properties to the present value of the future net revenue projected to be recovered from those properties according to methods prescribed by the SEC. In determining present value, the Company uses 12-month average prices for oil and natural gas (based on first day of the month prices and adjusted for hedging). If, at the end of any quarter, the amount of the unamortized investment exceeds the net present value of the projected future cash flows, such investment may be considered to be impaired, and the full cost accounting rules require that the investment must be written down to the calculated net present value. Such an instance would require the Company to recognize an immediate expense in that quarter, and its earnings would be reduced. Depending on the magnitude of any decrease in average prices, that charge could be material.

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 or discharge of contaminants 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 control air emissions and 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 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.

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussion or implementation. Under the Federal Clean Air Act, the EPA requires that new stationary sources of significant greenhouse gas emissions or major modifications of existing facilities obtain permits covering such emissions. The EPA is also considering other regulatory options to regulate greenhouse emissions from the energy industry. In addition, the U.S. Congress has from time to time considered bills that would establish a cap-and-trade program to reduce emissions of greenhouse gases. Legislation or regulation that restricts greenhouse gas emissions could increase the Company s cost of environmental compliance by requiring the Company to install new equipment to reduce emissions from larger facilities and/or purchase emission allowances. International, federal, state or regional climate change and greenhouse gas initiatives could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard to existing and new facilities, or impose additional monitoring and reporting requirements. Climate change and greenhouse gas initiatives, and incentives to conserve energy or use alternative energy sources, could also reduce demand for oil and natural gas. 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.

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

Due to the burgeoning Marcellus Shale natural gas play in the northeast United States, together with the fiscal difficulties faced by state governments in New York and Pennsylvania, various state legislative and regulatory initiatives regarding the exploration and production business have been proposed. 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 or state 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 and public disclosure of hydraulic fracturing fluid constituents. Implementing regulations, which will include new permit requirements, must be adopted by January 1, 2015. These and any other new state or federal 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 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.

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. 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 harms. These harms may require significant expenditures 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. These security incidents may have an adverse impact on the Company s operations, earnings and financial condition.

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.

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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. 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 $5.2 billion at September 30, 2013. Approximately 45.1% of this investment was in the Utility and Pipeline and Storage segments, whose operations are located primarily in western and central New York and northwestern Pennsylvania. The Exploration and Production segment comprises 50.5% of the Company s investment in net property, plant and equipment, and is primarily located in California and in the Appalachian region of the United States. The Gathering segment comprises 3.1% 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 (1.3%). 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 increased $2.0 billion, or 63.3%, since 2008. As part of its strategy to focus its exploration and production activities within the Appalachian region of the United States, specifically within the Marcellus Shale, the Company sold its off-shore oil and natural gas properties in the Gulf of Mexico in April 2011. The net property, plant and equipment associated with these properties was $55.4 million. The Company also sold on-shore oil and natural gas properties in its West Coast region in May 2011 with net property, plant and equipment of $8.1 million. In September 2010, the Company sold its landfill gas operations in the states of Ohio, Michigan, Kentucky, Missouri, Maryland and Indiana. The net property, plant and equipment of the landfill gas operations at the date of sale was $8.8 million.

The Utility segment had a net investment in property, plant and equipment of $1.2 billion at September 30, 2013. The net investment in its gas distribution network (including 14,759 miles of distribution pipeline) and its service connections to customers represent approximately 50% and 35%, respectively, of the Utility segment s net investment in property, plant and equipment at September 30, 2013.

The Pipeline and Storage segment had a net investment of $1.1 billion in property, plant and equipment at September 30, 2013. Transmission pipeline represents 38% of this segment s total net investment and includes 2,368 miles of pipeline utilized to move large volumes of gas throughout its service area. Storage facilities represent 18% of this segment s total net investment and consist of 31 storage fields operating at a combined working gas level of 73.4 Bcf, four of which are jointly owned and operated with other interstate gas pipeline companies, and 430 miles of pipeline. Net investment in storage facilities includes $81.7 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 33 compressor stations with 141,704 installed compressor horsepower that represent 21% of this segment s total net investment in property, plant and equipment.

The Exploration and Production segment had a net investment in property, plant and equipment of $2.6 billion at September 30, 2013.

The Gathering segment had a net investment of $0.2 billion in property, plant and equipment at September 30, 2013. Gathering lines and related compressors comprise substantially all of this segment s total net investment, including 57 miles of lines utilized to move Appalachian production (including Marcellus Shale) to various transmission pipeline receipt points.

The Utility and Pipeline and Storage segments facilities provided the capacity to meet Supply Corporation s 2013 peak day sendout, including transportation service, of 1,824 MMcf, which occurred on January 24, 2013. Withdrawals from storage of 615.9 MMcf provided approximately 33.8% 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 and purchase of, natural gas and oil reserves in California, the Appalachian region of the United States and Kansas. The Company has been increasing its emphasis in the Appalachian region, primarily in the Marcellus Shale, and sold its off-shore oil and natural gas properties in the Gulf of Mexico during 2011, as mentioned above. Further discussion of oil and gas producing activities is included in Item 8, Note M Supplementary Information for Oil and Gas Producing Activities. Note M sets forth proved developed and undeveloped reserve information for Seneca. The September 30, 2013, 2012 and 2011 reserves shown in Note M have been impacted by the SEC s final rule on Modernization of Oil and Gas Reporting. The most notable change of the final rule includes the replacement of the single day period-end pricing used to value oil and gas reserves with 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.

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 25 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 for the past ten years. He is a member of the Society of Petroleum 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.

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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 (with 15 years of experience in petroleum engineering and consulting at NSAI since 2004) and a professional geoscientist registered in the State of Texas (with 16 years of experience in petroleum geosciences and consulting at NSAI since 2008). NSAI was satisfied with the methods and procedures used by the Company to prepare its reserve estimates at September 30, 2013 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.

Seneca s proved developed and undeveloped natural gas reserves increased from 988 Bcf at September 30, 2012 to 1,300 Bcf at September 30, 2013. This increase is attributed to extensions and discoveries of 362 Bcf (355 Bcf in the Marcellus Shale) and positive revisions of previous estimates of 53 Bcf which was partially offset by production of 104 Bcf. Total gas revisions of 53 Bcf were comprised of 8 Bcf in upward gas pricing revisions and 45 Bcf in upward performance revisions. Price related revisions were a result of higher trailing twelve month average gas prices (Dominion South Point average gas price increased $0.64 per MMBtu from $2.84 per MMBtu to $3.48 per MMBtu). Upward performance revisions of 45 Bcf were primarily in the Marcellus Shale and included an 11 Bcf upward revision to Marcellus PUD reserves transferred to developed and a 19 Bcf downward revision to remaining Marcellus PUD reserves.

Seneca s proved developed and undeveloped oil reserves decreased from 42,862 Mbbl at September 30, 2012 to 41,598 Mbbl at September 30, 2013. Extensions and Discoveries of 2,443 Mbbl were exceeded by production of 2,831 Mbbl primarily occurring in the West Coast region (2,803 Mbbl) and downward Revisions of Previous Estimates of 876 Mbbl. On a Bcfe basis, Seneca s proved developed and undeveloped reserves increased from 1,246 Bcfe at September 30, 2012 to 1,549 Bcfe at September 30, 2013.

Seneca s proved developed and undeveloped natural gas reserves increased from 675 Bcf at September 30, 2011 to 988 Bcf at September 30, 2012. This increase was attributed primarily to extensions and discoveries of 436 Bcf, primarily in the Appalachian region (435 Bcf), which were partially offset by production of 66 Bcf and negative revisions of previous estimates of 56 Bcf. Total gas revisions of negative 56 Bcf were comprised of negative 61 Bcf in gas pricing revisions, partially offset by 5 Bcf in positive performance revisions. Negative price related revisions were mainly a result of lower trailing twelve month average gas prices (Dominion South Point average gas price fell $1.45 per MMBtu from $4.29 per MMBtu to $2.84 per MMBtu) making a number of undeveloped gas wells uneconomic at those prices. Of the 61 Bcf in negative price related revisions, 28 Bcf were related to the non-operated Marcellus joint venture, primarily in Clearfield County, Pennsylvania. Poor well performance from non-operated Marcellus joint venture activity, primarily in Clearfield County, also resulted in 38 Bcf in negative performance revisions. These were more than offset by 43 Bcf of positive performance revisions from Seneca operated Marcellus Shale activity.

Seneca s proved developed and undeveloped oil reserves decreased from 43,345 Mbbl at September 30, 2011 to 42,862 Mbbl at September 30, 2012. Extensions and discoveries of 1,257 Mbbl and positive revisions of previous estimates of 1,130 Mbbl were exceeded by production of 2,870 Mbbl, primarily occurring in the West Coast region (2,834 Mbbl). On a Bcfe basis, Seneca s proved developed and undeveloped reserves increased from 935 Bcfe at September 30, 2011 to 1,246 Bcfe at September 30, 2012.

The Company s proved undeveloped (PUD) reserves increased from 410 Bcfe at September 30, 2012 to 452 Bcfe at September 30, 2013. Undeveloped reserves in the Marcellus Shale increased from 381 Bcf at September 30, 2012 to 432 Bcf at September 30, 2013. The Company s total PUD reserves are 29% of total proved reserves at September 30, 2013, down from 33% of total proved reserves at September 30, 2012.

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The Company s proved undeveloped (PUD) reserves increased from 295 Bcfe at September 30, 2011 to 410 Bcfe at September 30, 2012. PUD reserves in the Marcellus Shale increased from 253 Bcf at September 30, 2011 to 381 Bcf at September 30, 2012. There was a material increase in PUD reserves at September 30, 2012 and 2011 as a result of Marcellus Shale reserve additions. The Company s total PUD reserves are 33% of total proved reserves at September 30, 2012, up from 32% of total proved reserves at September 30, 2011.

The increase in PUD reserves in 2013 of 42 Bcfe is a result of 221 Bcfe in new PUD reserve additions (219 Bcfe from the Marcellus Shale), offset by 160 Bcfe in PUD conversions to developed reserves and 19 Bcfe in downward PUD revisions. The downward revisions were primarily due to reductions to planned lateral lengths for several horizontal wells in the Marcellus Shale.

The increase in PUD reserves in 2012 of 115 Bcfe was a result of 289 Bcfe in new PUD reserve additions (286 Bcfe from the Marcellus Shale), offset by 97 Bcfe in PUD conversions to proved developed reserves, and 77 Bcfe in downward PUD revisions of previous estimates. The downward revisions were primarily from the removal of proved locations in the Marcellus Shale due to a significant decrease in trailing twelve-month average gas prices at Dominion South Point. The decrease in prices made the reserves uneconomic to develop. Of these downward revisions, the majority (66 Bcfe) were related to non-operated Marcellus activity, primarily in Clearfield County.

The Company invested $149 million during the year ended September 30, 2013 to convert 160 Bcfe (171 Bcfe including revisions) of PUD reserves to developed reserves. This represents 39% of the PUD reserves booked at September 30, 2012. The Company invested $217 million during the year ended September 30, 2012 to convert 97 Bcfe of September 30, 2011 PUD reserves to proved developed reserves. This represented 33% of the PUD reserves booked at September 30, 2011. In 2014, the Company estimates that it will invest approximately $169 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, the Company developed 19% of its beginning year PUD reserves in fiscal 2010, 47% of its beginning year PUD reserves in fiscal 2011, 33% of its beginning year PUD reserves in fiscal 2012 and 39% of its beginning year PUD reserves in fiscal 2013.

At September 30, 2013, 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.

At September 30, 2013, the Company s Exploration and Production segment had delivery commitments of 504 Bcf. The Company expects to meet those commitments through proved reserves and the future development of reserves that are currently classified as proved undeveloped reserves and does not anticipate any issues or constraints that would prevent the Company from meeting these commitments.

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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		
	2013	2012	2011
United States			
Appalachian Region			
Average Sales Price per Mcf of Gas	$ 3.49(2)	$ 2.71(2)	$ 4.37(2)
Average Sales Price per Barrel of Oil	$ 96.48	$ 93.94	$ 86.58
Average Sales Price per Mcf of Gas (after hedging)	$ 4.00	$ 4.19	$ 5.24
Average Sales Price per Barrel of Oil (after hedging)	$ 96.48	$ 93.94	$ 86.58
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.67(2)	$ 0.68(2)	$ 0.59(2)
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	276(2)	172(2)	118(2)
West Coast Region			
Average Sales Price per Mcf of Gas (3)	$ 6.61	$ 6.27	$ 7.63
Average Sales Price per Barrel of Oil	$ 103.14	$ 107.13	$ 96.45
Average Sales Price per Mcf of Gas (after hedging) (3)	$ 7.12	$ 8.54	$ 10.27
Average Sales Price per Barrel of Oil (after hedging)	$ 98.23	$ 90.84	$ 80.51
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 2.61	$ 1.98	$ 2.06
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	55	56	53
Gulf Coast Region			
Average Sales Price per Mcf of Gas			$ 5.02
Average Sales Price per Barrel of Oil			$ 88.57
Average Sales Price per Mcf of Gas (after hedging)			$ 5.50
Average Sales Price per Barrel of Oil (after hedging)			$ 88.57
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced			$ 1.59
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)			25(1)
Total Company			
Average Sales Price per Mcf of Gas	$ 3.58	$ 2.89	$ 4.64
Average Sales Price per Barrel of Oil	$ 103.07	$ 106.97	$ 95.78
Average Sales Price per Mcf of Gas (after hedging)	$ 4.10	$ 4.42	$ 5.60
Average Sales Price per Barrel of Oil (after hedging)	$ 98.21	$ 90.88	$ 81.13
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.99	$ 1.00	$ 1.08
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	331	228	185

(1) The Gulf Coast Region s off-shore properties were sold in April 2011.

(2) The Marcellus Shale fields (which exceed 15% of total reserves at 9/30/2013, 9/30/2012 and 9/30/2011) contributed 258 MMcfe, 152 MMcfe and 97 MMcfe of daily production in 2013, 2012 and 2011, respectively. The average sales price (per Mcfe) was $3.49 ($4.04 after hedging) in 2013, $2.67 ($3.66 after hedging) in 2012 and $4.34 ($4.68 after hedging) in 2011. The average lifting costs (per Mcfe) were $0.64 in 2013, $0.61 in 2012 and $0.48 in 2011.

(3) Prices for all periods presented reflect revenues from gas produced on the West Coast, including natural gas liquids. In previous years, natural gas liquids were reported as gas processing plant revenues as opposed to natural gas revenues.

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Productive Wells

At September 30, 2013		Appalachian Region Gas	Appalachian Region Oil	West Coast Region Gas	West Coast Region Oil	Total Company Gas	Total Company Oil
Productive Wells	Gross	2,902	1		1,895	2,902	1,896
Productive Wells	Net	2,849	1		1,866	2,849	1,867

Developed and Undeveloped Acreage

At September 30, 2013	Appalachian Region	West Coast Region	Total Company
Developed Acreage			
Gross	558,690	21,474	580,164
Net	548,959	18,931	567,890
Undeveloped Acreage			
Gross	377,657	27,576	405,233
Net	359,108	14,695	373,803
Total Developed and Undeveloped Acreage			
Gross	936,347	49,050	985,397
Net	908,067	33,626	941,693

As of September 30, 2013, the aggregate amount of gross undeveloped acreage expiring in the next three years and thereafter are as follows: 6,400 acres in 2014 (4,818 net acres), 20,434 acres in 2015 (17,689 net acres), 8,112 acres in 2016 (6,442 net acres), and 62,778 acres thereafter (50,314 net acres). The remaining 307,509 gross acres (294,540 net acres) represent non-expiring oil and gas rights owned by the Company.

Drilling Activity

	Productive			Dry		
For the Year Ended September 30	2013	2012	2011	2013	2012	2011
United States						
Appalachian Region						
Net Wells Completed						
Exploratory		7.00	13.00	1.00		
Development	39.50	50.50	48.76	2.50	2.00	
West Coast Region						
Net Wells Completed						
Exploratory	0.63		0.25			
Development	75.00	56.99	43.31			
Gulf Coast Region						
Net Wells Completed						
Exploratory						
Development			0.40			
Total Company						
Net Wells Completed						
Exploratory	0.63	7.00	13.25	1.00		
Development	114.50	107.49	92.47	2.50	2.00	

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Present Activities

At September 30, 2013	Appalachian Region	West Coast Region	Total Company
Wells in Process of Drilling(1)			
Gross	76.00		76.00
Net	61.00		61.00

(1) Includes wells awaiting completion.

Item 3 ***Legal Proceedings***

On November 14, 2012, the PaDEP sent a draft Consent Assessment of Civil Penalty to a subsidiary of Midstream Corporation. The draft consent offers to settle various alleged violations of the Pennsylvania Clean Streams Law and the PaDEP s rules and regulations regarding erosion and sedimentation control if the Company would consent to a civil penalty. The amount of the penalty sought by the PaDEP is not material to the Company. The Company disputes many of the alleged violations and will vigorously defend its position in negotiations with the PaDEP. The alleged violations occurred during construction of the Company s Trout Run Gathering System following historic rainfall and flooding in the fall of 2011. The Company has spent over $128 million in constructing this project.

On August 7, 2013, the PaDEP sent a draft Consent Assessment of Civil Penalty to Seneca, alleging certain violations of state laws and regulations relating to Seneca s drilling activities. The draft consent addressed environmental and administrative violations identified by PaDEP during inspections of 15 well sites in four counties over the course of nearly three years. In October 2013, Seneca settled this matter with the PaDEP and paid a civil penalty of $198,500.

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

Item 4 ***Mine Safety Disclosures***

Not Applicable.

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PART II

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

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, Item 8 at Note E Capitalization and Short-Term Borrowings, and at Note L Market for Common Stock and Related Shareholder Matters (unaudited).

On July 1, 2013, the Company issued a total of 3,850 unregistered shares of Company common stock to the seven non-employee directors of the Company then serving on the Board of Directors of the Company, 550 shares to each such director. All of these unregistered shares were issued under the Company s 2009 Non-Employee Director Equity Compensation Plan as partial consideration for such directors services during the quarter ended September 30, 2013. 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, 2013	5,679	$ 62.82		6,971,019
Aug. 1-31, 2013	9,674	$ 65.56		6,971,019
Sept. 1-30, 2013	6,891	$ 67.35		6,971,019
Total	22,244	$ 65.42		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 options, SARs or shares of restricted stock for the payment of option exercise prices or applicable withholding taxes. During the quarter ended September 30, 2013, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program. Of the 22,244 shares purchased other than through a publicly announced share repurchase program, 16,784 were purchased for the Company s 401(k) plans and 5,460 were purchased as a result of shares tendered to the Company by holders of stock options, SARs or shares of restricted stock.

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

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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 SIG Oil Exploration & Production Index for the period September 30, 2008 through September 30, 2013. The graph assumes that the value of the investment in the Company s common stock and in each index was $100 on September 30, 2008 and that all dividends were reinvested.

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.

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Item 6 ***Selected Financial Data***

	Year Ended September 30				
	2013	2012	2011	2010	2009
	(Thousands, except per share amounts and number of registered shareholders)				
Summary of Operations					
Operating Revenues	$ 1,829,551	$ 1,626,853	$ 1,778,842	$ 1,760,503	$ 2,051,543
Operating Expenses:					
Purchased Gas	460,432	415,589	628,732	658,432	997,216
Operation and Maintenance	442,090	401,397	400,519	394,569	401,200
Property, Franchise and Other Taxes	82,431	90,288	81,902	75,852	72,102
Depreciation, Depletion and Amortization	326,760	271,530	226,527	191,199	170,620
Impairment of Oil and Gas Producing Properties					182,811
	1,311,713	1,178,804	1,337,680	1,320,052	1,823,949
Operating Income	517,838	448,049	441,162	440,451	227,594
Other Income (Expense):					
Gain on Sale of Unconsolidated Subsidiaries			50,879		
Impairment of Investment in Partnership					(1,804)
Other Income	4,697	5,133	5,947	6,126	11,566
Interest Income	4,335	3,689	2,916	3,729	5,776
Interest Expense on Long-Term Debt	(90,273)	(82,002)	(73,567)	(87,190)	(79,419)
Other Interest Expense	(3,838)	(4,238)	(4,554)	(6,756)	(7,370)
Income from Continuing Operations Before Income Taxes	432,759	370,631	422,783	356,360	156,343
Income Tax Expense	172,758	150,554	164,381	137,227	52,859
Income from Continuing Operations	260,001	220,077	258,402	219,133	103,484
Discontinued Operations:					
Income (Loss) from Operations, Net of Tax				470	(2,776)
Gain on Disposal, Net of Tax				6,310	
Income (Loss) from Discontinued Operations, Net of Tax				6,780	(2,776)
Net Income Available for Common Stock	$ 260,001	$ 220,077	$ 258,402	$ 225,913	$ 100,708
Per Common Share Data					
Basic Earnings from Continuing Operations per Common Share	$ 3.11	$ 2.65	$ 3.13	$ 2.70	$ 1.29
Diluted Earnings from Continuing Operations per Common Share	$ 3.08	$ 2.63	$ 3.09	$ 2.65	$ 1.28
Basic Earnings per Common Share(1)	$ 3.11	$ 2.65	$ 3.13	$ 2.78	$ 1.26
Diluted Earnings per Common Share(1)	$ 3.08	$ 2.63	$ 3.09	$ 2.73	$ 1.25
Dividends Declared	$ 1.48	$ 1.44	$ 1.40	$ 1.36	$ 1.32
Dividends Paid	$ 1.47	$ 1.43	$ 1.39	$ 1.35	$ 1.31
Dividend Rate at Year-End	$ 1.50	$ 1.46	$ 1.42	$ 1.38	$ 1.34
At September 30:					
Number of Registered Shareholders	13,215	13,800	14,355	15,549	16,098

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	Year Ended September 30				
	2013	2012	2011	2010	2009
	(Thousands, except per share amounts and number of registered shareholders)				
Net Property, Plant and Equipment					
Utility	$ 1,246,943	$ 1,217,431	$ 1,189,030	$ 1,165,240	$ 1,144,002
Pipeline and Storage	1,074,079	1,069,070	954,554	858,231	839,424
Exploration and Production	2,600,448	2,273,030	1,753,194	1,338,956	1,041,846
Energy Marketing	2,002	1,530	850	436	71
Gathering	161,111	110,269	31,962	15,585	8,116
All Other(2)	62,554	63,245	65,266	65,518	92,988
Corporate	4,589	5,228	5,668	6,263	6,915
Total Net Plant	$ 5,151,726	$ 4,739,803	$ 4,000,524	$ 3,450,229	$ 3,133,362
Total Assets	$ 6,218,347	$ 5,935,142	$ 5,221,084	$ 5,047,054	$ 4,769,129
Capitalization					
Comprehensive Shareholders Equity	$ 2,194,729	$ 1,960,095	$ 1,891,885	$ 1,745,971	$ 1,589,236
Long-Term Debt, Net of Current Portion	1,649,000	1,149,000	899,000	1,049,000	1,249,000
Total Capitalization	$ 3,843,729	$ 3,109,095	$ 2,790,885	$ 2,794,971	$ 2,838,236

(1) Includes discontinued operations.

(2) Includes net plant of landfill gas discontinued operations as follows: $0 for 2013, 2012, 2011 and 2010 and $9,296 for 2009.

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

OVERVIEW

The Company is a diversified energy company and reports financial results for five business segments: Utility, Pipeline and Storage, Exploration and Production, Energy Marketing, and Gathering. Prior to this Form 10-K, the Company had reported financial results for Midstream Corporation within the All Other category, however Midstream Corporation s financial results are now presented as the Gathering segment. Strong growth in Marcellus Shale production within the Appalachian region and recent and projected growth in gathering facilities led to the decision to report Midstream Corporation s financial results as a separate segment. Prior year segment information has been restated to reflect this change in presentation. Refer to Item 1, Business, for a more detailed description of each of the segments. 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) 2013 and projected 2014 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.

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For the year ended September 30, 2013 compared to the year ended September 30, 2012, the Company experienced an increase in earnings of $39.9 million. The earnings increase reflects increases in all of the Company s segments. For further discussion of the Company s earnings, refer to the Results of Operations section below.

The Company s natural gas reserve base has grown substantially in recent years due to its development of reserves in the Marcellus Shale, a Middle Devonian-age geological shale formation that is present nearly a mile or more below the surface in the Appalachian region of the United States, including much of Pennsylvania and southern New York. The Company controls the natural gas interests associated with approximately 775,000 net acres within the Marcellus Shale area, with a majority of the interests held in fee, carrying no royalty and no lease expirations. Natural gas proved developed and undeveloped reserves in the Appalachian region increased from 925 Bcf at September 30, 2012 to 1,239 Bcf at September 30, 2013. The Company has spent significant amounts of capital in this region related to the development of such reserves. For the year ended September 30, 2013, the Company s Exploration and Production segment had capital expenditures of $428.5 million in the Appalachian region, of which $393.3 million was spent towards the development of the Marcellus Shale. The Company s fiscal 2014 estimated capital expenditures in the Exploration and Production segment s Appalachian region are expected to be approximately $530.1 million. Forecasted production in the Exploration and Production segment s Appalachian region for fiscal 2014 is expected to be in the range of 125 to 143 Bcfe, up from actual production of 101 Bcfe in fiscal 2013.

From a capital resources perspective, the Company has largely been able to meet its capital expenditure needs by using cash from operations as well as both short and long-term debt. In February 2013, the Company issued $500.0 million of 3.75% notes due in March 2023 to, among other matters, refund $250.0 million of 5.25% notes that matured in March 2013 and to reduce short-term debt. It is expected that the Company will use short-term debt as necessary during fiscal 2014 to help meet its capital expenditure needs.

The well completion technology referred to as hydraulic fracturing used in conjunction with horizontal drilling continues to be debated. In Pennsylvania, where the Company is focusing its Marcellus Shale development efforts, the permitting and regulatory processes seem to strike a balance between the environmental concerns associated with hydraulic fracturing and the benefits of increased natural gas production. Hydraulic fracturing is a well stimulation technique that has been used for many years, and in the Company s experience, one that the Company believes has little negative impact to the environment. Nonetheless, the potential for increased state or federal regulation of hydraulic fracturing could impact future costs of drilling in the Marcellus Shale and lead to operational delays or restrictions. There is also the risk that drilling could be prohibited on certain acreage that is prospective for the Marcellus Shale. Please refer to the Risk Factors section above for further discussion.

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, 2013, the ceiling exceeded the book value of the Company s oil and gas properties by approximately $159.4 million. The 12-month average of the first day of the month price for crude oil for each month during 2013, based on posted Midway Sunset prices, was $101.52 per Bbl. The 12-month average of the first day of the month price for natural gas for each month during 2013, based on the quoted Henry Hub spot price for natural gas, was $3.605 per MMBtu. (Note Because actual pricing of the Company s various producing properties varies depending on their location and hedging, the actual various prices received for such production is utilized to calculate the ceiling, rather than the Midway Sunset and Henry Hub prices, which are only indicative of 12-month average prices for 2013.) If natural gas average prices used in the ceiling test calculation at September 30, 2013 had been $1 per MMBtu lower, the book value of the Company s oil and gas properties would have exceeded the ceiling by approximately $135.5 million, which would have resulted in an impairment charge. If crude oil average prices used in the ceiling test calculation at September 30, 2013 had been $5 per Bbl lower, the ceiling would have exceeded the book value of the Company s oil and gas properties by approximately $118.1 million which would not have resulted in an impairment charge. If both natural gas and crude oil average prices used in the ceiling test calculation at September 30, 2013 were lower by $1 per MMBtu and $5 per Bbl, respectively, the book value of the Company s oil and gas properties would have exceeded the ceiling by approximately $176.7 million, which would have resulted in an impairment charge. These calculated amounts are based solely on price changes and do not take into account any other changes to the ceiling test calculation.

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 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. 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. Some instruments are accounted for as economic hedges. Gains or losses on economic hedges are marked-to-market. As discussed below, the Company recorded pre-tax mark to market losses of $3.7 million in its Exploration and Production segment in 2013. This included $1.7 million associated with economic hedges that do not qualify as cash flow or fair value hedges.

The Company uses both exchange-traded and non exchange-traded derivative financial instruments. The Company follows the authoritative guidance for fair value measurements. As such, the fair value of such derivative financial instruments is determined under the provisions of this guidance. The fair value of exchange traded derivative financial instruments is determined from Level 1 inputs, which are quoted prices in active markets. The Company determines the fair value of non exchange-traded derivative financial instruments based on an internal model, which uses both observable and unobservable inputs other than quoted prices. These inputs are considered Level 2 or Level 3 inputs. All derivative financial instrument assets and liabilities are evaluated for the probability of default by either the counterparty or the Company. Credit reserves are applied against the fair values of such assets or liabilities. Refer to the Market Risk Sensitive Instruments section below for further discussion of the Company s 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 utilizes the Mercer Yield Curve Above Mean Model to determine the discount rate. The yield curve is a spot rate yield curve that provides a zero-coupon interest rate for each year into the future. Each year s anticipated benefit payments are discounted at the associated spot interest rate back to the measurement date. The discount rate is then determined based on the spot interest rate that results in the same present value when applied to the same anticipated benefit payments. In determining the spot rates, the model will exclude coupon interest rates that are in the lower 50th percentile 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 was changed from 3.50% in 2012 to 4.75% in 2013. The change in the discount rate from 2012 to 2013 decreased the Retirement Plan projected benefit obligation by $147.9 million and the accumulated post-retirement benefit obligation by $75.9 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 2013, the actual return on plan assets exceeded the expected return, which improved the funded status of the Retirement Plan ($41.4 million) as well as the VEBA trusts and 401(h) accounts ($28.8 million). The actual versus expected benefit payments for 2013 caused a decrease of $4.6 million to the accumulated post-retirement benefit obligation. 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 8 years for the Retirement Plan and 7 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.

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RESULTS OF OPERATIONS

EARNINGS

2013 Compared with 2012

The Company s earnings were $260.0 million in 2013 compared with earnings of $220.1 million in 2012. The increase in earnings of $39.9 million is the result of higher earnings in all segments. Higher earnings in the All Other category and a lower loss in the Corporate category also contributed to the increase in earnings. 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 events in 2013 and 2012:

2013 Event

A $4.9 million refund provision recorded in the Utility segment related to various issues raised in Distribution Corporation s rate proceeding in New York.

2012 Events

The elimination of Supply Corporation s other post-retirement regulatory liability of $12.8 million recorded in the Pipeline and Storage segment, as specified by Supply Corporation s rate case settlement; and

A natural gas impact fee imposed by the Commonwealth of Pennsylvania in 2012 on the drilling of wells in the Marcellus Shale by the Exploration and Production segment. This fee included $4.0 million related to wells drilled prior to 2012. See further discussion of the impact fee that follows under the heading Exploration and Production.

2012 Compared with 2011

The Company s earnings were $220.1 million in 2012 compared with earnings of $258.4 million in 2011. The decrease in earnings of $38.3 million is primarily the result of lower earnings in the All Other category, Exploration and Production segment, Utility segment and Energy Marketing segment. Higher earnings in the Pipeline and Storage segment and the Gathering segment, as well as a lower loss in the Corporate category partly offset these decreases. Earnings were impacted by the 2012 events discussed above and the following event in 2011:

2011 Event

A $50.9 million ($31.4 million after tax) gain on the sale of unconsolidated subsidiaries as a result of the Company s sale of its 50% equity method investments in Seneca Energy and Model City.

Earnings (Loss) by Segment

	Year Ended September 30		
	2013	2012 (Thousands)	2011
Utility	$ 65,686	$ 58,590	$ 63,228
Pipeline and Storage	63,245	60,527	31,515
Exploration and Production	115,391	96,498	124,189
Energy Marketing	4,589	4,169	8,801
Gathering	13,321	6,855	4,873

Total Reported Segments	262,232	226,639	232,606
All Other	894	13	33,629
Corporate	(3,125)	(6,575)	(7,833)
Total Consolidated	$ 260,001	$ 220,077	$ 258,402

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UTILITY

Revenues

Utility Operating Revenues

	Year Ended September 30 2013	2012 (Thousands)	2011
Retail Revenues:			
Residential	$ 513,654	$ 493,354	$ 603,838
Commercial	66,602	61,314	80,811
Industrial	6,096	5,359	5,849
	586,352	560,027	690,498
Off-System Sales	25,020	27,010	33,968
Transportation	135,273	122,316	123,729
Other	(306)	9,769	4,300
	$ 746,339	$ 719,122	$ 852,495

Utility Throughput million cubic feet (MMcf)

	Year Ended September 30 2013	2012	2011
Retail Sales:			
Residential	52,753	47,036	57,466
Commercial	7,486	6,682	8,517
Industrial	947	837	723
	61,186	54,555	66,706
Off-System Sales	6,717	9,544	7,151
Transportation	69,149	61,027	66,273
	137,052	125,126	140,130

Degree Days

Year Ended September 30		Normal	Actual	Percent (Warmer) Colder Than Normal	Prior Year
2013(1):	Buffalo	6,617	6,139	(7.2)%	15.9%
	Erie	6,147	5,888	(4.2)%	17.8%
2012(2):	Buffalo	6,729	5,296	(21.3)%	(21.6)%
	Erie	6,277	4,999	(20.4)%	(21.4)%
2011(3):	Buffalo	6,692	6,751	0.9%	7.3%

Erie	6,243	6,359	1.9%	6.9%

(1) Percents compare actual 2013 degree days to normal degree days and actual 2013 degree days to actual 2012 degree days. Normal degree days for 2013 reflect a revision from the National Oceanic and Atmospheric Administration.

(2) Percents compare actual 2012 degree days to normal degree days and actual 2012 degree days to actual 2011 degree days. Normal degree days for 2012 reflect the fact that 2012 was a leap year.

(3) Percents compare actual 2011 degree days to normal degree days and actual 2011 degree days to actual 2010 degree days.

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2013 Compared with 2012

Operating revenues for the Utility segment increased $27.2 million in 2013 compared with 2012. This increase largely resulted from a $26.3 million increase in retail gas sales revenues and a $13.0 million increase in transportation revenue. These were partially offset by a $10.1 million decrease in other operating revenues and a $2.0 million decrease in off-system sales (due to lower volume). Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal.

The $26.3 million increase in retail gas sales revenues was largely a function of higher volume (6.6 Bcf) due to colder weather. The $13.0 million increase in transportation revenues was primarily due to an 8.1 Bcf increase in transportation throughput, largely the result of colder weather compared to the prior period and the migration of customers from retail sales to transportation services. The $10.1 million decrease in other operating revenues was largely due to a $7.5 million refund provision recorded during fiscal 2013 related to various issues raised in a New York rate proceeding combined with a downward adjustment in the carrying value of certain regulatory assets during the fourth quarter of fiscal 2013. In addition, a decline in capacity release revenues led to a decline in other revenues. As a result of the unusually warm winter during fiscal 2012, the demand for capacity release volume decreased as contracts for Distribution Corporation s fiscal 2013 capacity were being executed, which led to a decrease in the capacity release rates and revenues.

2012 Compared with 2011

Operating revenues for the Utility segment decreased $133.4 million in 2012 compared with 2011. This decrease largely resulted from a $130.5 million decrease in retail gas sales revenues and a $7.0 million decrease in off-system sales revenue. These were partially offset by a $5.5 million increase in other operating revenues.

The $130.5 million decrease in retail gas sales revenues was largely a function of lower volume (12.2 Bcf) due to warmer weather combined with the recovery of lower gas costs. Subject to certain timing variations, gas costs are recovered dollar for dollar in customer rates. See further discussion of purchased gas below under the heading Purchased Gas. The $7.0 million decrease in off-system sales was largely the result of a change in gas purchase strategy whereby Distribution Corporation eliminated contractual commitments to purchase gas from the southwest region of the United States during the April through October time period. With the elimination of such commitments, there was a corresponding reduction in the ability to conduct off-system sales during that period. Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal and there is not a material impact to margins. The $5.5 million increase in other operating revenues largely reflects the fact that there was a downward adjustment to the carrying value of certain regulatory asset accounts in the fourth quarter of 2011 that did not recur in 2012.

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 $362.3 million, $340.3 million and $460.1 million of Purchased Gas expense during 2013, 2012 and 2011, 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.

Currently, Distribution Corporation has contracted for long-term firm transportation capacity with Supply Corporation, Empire and seven other upstream pipeline companies, for long-term gas supplies with a combination of producers and marketers, and for storage service with Supply Corporation and two nonaffiliated companies. In addition, Distribution Corporation satisfies a portion of its gas requirements through spot market purchases. Additional discussion of the Utility segment s gas purchases appears under the heading Sources and Availability of Raw Materials in Item 1.

Earnings

2013 Compared with 2012

The Utility segment s earnings in 2013 were $65.7 million, an increase of $7.1 million when compared with earnings of $58.6 million in 2012. The increase in earnings is largely attributable to colder weather ($7.0 million), the positive earnings impact of lower interest expense ($2.7 million), lower income tax expense ($1.2 million), and higher usage ($0.7 million). These increases were partially offset by a $4.9 million refund provision discussed above. Usage refers to average gas consumption per account after factoring out any impact that weather may have had on consumption. The decrease in interest expense is due to a decrease in the weighted average amount of debt outstanding due to the Utility segment s share of the Company s $250 million of notes that matured in March 2013. The decrease in income tax expense is a result of a favorable tax settlement.

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 2013 and 2012, the WNC preserved earnings of approximately $2.1 million and $5.9 million, respectively, as the weather was warmer than normal.

2012 Compared with 2011

The Utility segment s earnings in 2012 were $58.6 million, a decrease of $4.6 million when compared with earnings of $63.2 million in 2011. The decrease in earnings was largely attributable to warmer weather ($10.1 million) and higher depreciation of $1.3 million (largely the result of depreciation adjustments for certain assets). These decreases were partially offset by regulatory true-up adjustments of $2.5 million (mostly due to adjustments of the carrying value of regulatory assets discussed above), lower income tax expense of $1.1 million (as a result of the benefits associated with the tax sharing agreement with affiliated companies), the positive earnings impact of lower interest expense of $0.8 million (largely due to lower interest on deferred gas costs), lower property, franchise and other taxes of $0.9 million, higher interest income of $0.6 million (due to higher money market investment balances) and lower operating expenses of $0.3 million (largely due to decreased bad debt expense). The decrease in property, franchise and other taxes, which includes FICA taxes, was largely due to lower personnel costs and lower property taxes (as a result of a decrease in assessed property values).

For 2011, the WNC reduced earnings by approximately $1.0 million, as the weather was colder than normal.

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PIPELINE AND STORAGE

Revenues

Pipeline and Storage Operating Revenues

	Year Ended September 30		
	2013	2012	2011
		(Thousands)	
Firm Transportation	$ 190,470	$ 164,652	$ 134,652
Interruptible Transportation	2,152	1,431	1,341
	192,622	166,083	135,993
Firm Storage Service	70,555	67,929	66,712
Interruptible Storage Service	5	7	19
	70,560	67,936	66,731
Other	4,426	25,256	12,384
	$ 267,608	$ 259,275	$ 215,108

Pipeline and Storage Throughput (MMcf)

	Year Ended September 30		
	2013	2012	2011
Firm Transportation	575,805	369,477	317,917
Interruptible Transportation	3,997	1,662	2,037
	579,802	371,139	319,954

2013 Compared with 2012

Operating revenues for the Pipeline and Storage segment increased $8.3 million in 2013 as compared with 2012. The increase was primarily due to an increase in transportation revenues of $26.5 million and an increase in storage revenues of $2.6 million. The increase in transportation revenues was largely due to demand charges on new contracts for transportation service on Supply Corporation s Line N 2012 Expansion Project, which was placed fully in service in November 2012, and Supply Corporation s Northern Access expansion project, which was placed fully in service in January 2013. These projects provide pipeline capacity for Marcellus Shale production. The Line N 2012 Expansion Project and the Northern Access expansion project are discussed in the Investing Cash Flow section that follows. Additionally, effective May 2012, both transportation and storage revenues increased due to an overall net increase in tariff rates as a result of the implementation of Supply Corporation s rate case settlement which was approved by FERC on August 6, 2012. Partially offsetting these increases was a decrease in other operating revenues. Other operating revenues in fiscal 2012 included the impact of Supply Corporation s elimination of a $21.7 million regulatory liability associated with post-retirement benefits. The elimination of the regulatory liability was specified in Supply Corporation s rate case settlement. The rate case and the settlement are discussed further in Item 8 at Note C Regulatory Matters.

Transportation volume increased by 208.7 Bcf in 2013 as compared with 2012. The large increase in transportation volume primarily reflects the impact of the above mentioned expansion projects being placed in service. Volume fluctuations generally do not have a significant impact on revenues as a result of the straight fixed-variable rate design utilized by Supply Corporation and Empire.

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2012 Compared with 2011

Operating revenues for the Pipeline and Storage segment increased $44.2 million in 2012 as compared with 2011. The increase was primarily due to an increase in transportation revenues of $30.1 million and an increase in storage revenues of $1.2 million. The increase in transportation revenues was largely due to new contracts for transportation service on Supply Corporation s Line N Expansion Project, which was placed in service in October 2011, and Empire s Tioga County Extension Project, which was placed in service in November 2011. Both projects provide pipeline capacity for Marcellus Shale production. Additionally, effective May 2012, both transportation and storage revenues increased due to an overall net increase in tariff rates as a result of the implementation of Supply Corporation s rate case settlement, as noted above. These increases more than offset a reduction in transportation revenues due to the turnback of other pipeline capacity at Niagara. Other operating revenues increased due to Supply Corporation s elimination of a $21.7 million regulatory liability associated with post-retirement benefits. The elimination of this regulatory liability was specified in Supply Corporation s rate case settlement. Partially offsetting these increases was a decrease in efficiency gas revenues of $9.3 million (reported as a part of other revenue in the table above) resulting from lower natural gas prices, lower efficiency gas volume and adjustments to reduce the carrying value of Supply Corporation s efficiency gas inventory to market value during the year ended September 30, 2012. The decrease in efficiency gas volume is a result of the implementation of Supply Corporation s rate settlement in May 2012. Prior to May 2012, under Supply Corporation s previous tariff with shippers, Supply Corporation was allowed to retain a set percentage of shipper-supplied gas as compressor fuel and for other operational purposes. To the extent that Supply Corporation did not utilize all of the gas to cover such operational needs, it was allowed to keep the excess gas as inventory. That inventory would later be sold to buyers on the open market. The excess gas that was retained as inventory, as well as any gains resulting from the sale of such inventory, represented efficiency gas revenue to Supply Corporation. Effective with the implementation of the rate settlement mentioned above, Supply Corporation implemented a tracking mechanism to adjust fuel retention rates annually to reflect actual experience, replacing the previously fixed fuel retention rates, thus eliminating the impact efficiency gas had to revenues and earnings prior to the rate settlement.

Transportation volume increased by 51.2 Bcf in 2012 as compared with 2011. Higher transportation volume for power generation on Empire s system during the spring and summer of fiscal 2012 more than offset lower transportation volume experienced by both Supply Corporation and Empire during the fall and winter of fiscal 2012 due to warmer weather. As discussed above, volume fluctuations generally do not have a significant impact on revenues as a result of the straight fixed-variable rate design utilized by Supply Corporation and Empire.

Earnings

2013 Compared with 2012

The Pipeline and Storage segment s earnings in 2013 were $63.2 million, an increase of $2.7 million when compared with earnings of $60.5 million in 2012. The increase in earnings is primarily due to the earnings impact of higher transportation and storage revenues of $19.0 million, as discussed above, combined with a decrease in depreciation expense ($2.0 million). The decrease in depreciation expense primarily reflects a decrease in depreciation rates as specified in Supply Corporation s rate case settlement offset partly by incremental depreciation expense related to the projects that were placed in service within the last year. Partially offsetting these increases was the non-recurrence of the fiscal 2012 elimination of Supply Corporation s post-retirement regulatory liability ($12.8 million), as discussed above. The earnings increases were also partially offset by higher operating expenses ($2.6 million), a decrease in the allowance for funds used during construction (equity component) of $1.4 million, higher property taxes ($0.5 million), higher interest expense ($0.4 million) and higher income taxes ($1.0 million). The increase in operating expenses can be attributed primarily to higher pension expense and an increase in compressor station costs, offset partly by lower post-retirement benefit costs. The decrease in the allowance for funds used during construction is mainly due to Supply Corporation s Line N 2012 Expansion Project and Supply Corporation s

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Northern Access expansion project, which were under construction in the prior year and have since been placed in service, and Empire s Tioga County Expansion Project, which remained under construction during a portion of the first quarter of fiscal 2012 before being placed in service in November 2011. The increase in property taxes was primarily a result of a higher tax base due to capital additions. Increased intercompany borrowings contributed to the increase in interest expense. The increase in income taxes is a result of a favorable federal return to provision adjustment in 2012 that did not recur in the current year combined with a reduced benefit associated with the allowance for funds used during construction.

2012 Compared with 2011

The Pipeline and Storage segment s earnings in 2012 were $60.5 million, an increase of $29.0 million when compared with earnings of $31.5 million in 2011. The increase in earnings was primarily due to the earnings impact of higher transportation and storage revenues of $20.3 million and the earnings impact associated with the elimination of Supply Corporation s post-retirement regulatory liability ($12.8 million), all of which are discussed above, combined with lower operating expenses ($2.7 million) and an increase in the allowance for funds used during construction (equity component) of $0.6 million mainly due to construction during the year ended September 30, 2012 on Supply Corporation s Northern Access and Line N 2012 expansion projects as well as Empire s Tioga County Extension Project. The decrease in operating expenses can be attributed primarily to a decrease in other post-retirement benefits expense, a decline in compressor station maintenance costs and a decrease in the reserve for preliminary project costs. The decrease in other post-retirement benefits expense reflects the implementation of Supply Corporation s rate settlement. These earnings increases were partially offset by the earnings impact associated with lower efficiency gas revenues ($6.1 million), as discussed above, higher depreciation expense ($0.6 million) and higher property taxes ($0.4 million). The increase in depreciation expense was mostly the result of additional projects that were placed in service in the last year offset partially by a decrease in depreciation rates as of May 2012 as a result of Supply Corporation s rate case settlement.

EXPLORATION AND PRODUCTION

Revenues

Exploration and Production Operating Revenues

	Year Ended September 30		
	2013	2012	2011
		(Thousands)	
Gas (after Hedging)	$ 424,735	$ 292,311	$ 282,646
Oil (after Hedging)	278,005	260,844	232,052
Gas Processing Plant	4,502	4,813	3,824
Other	(4,305)	212	513
Operating Revenues	$ 702,937	$ 558,180	$ 519,035

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Production

	Year Ended September 30		
	2013	2012	2011
Gas Production *(MMcf)*			
Appalachia	100,633	62,663	42,979
West Coast	3,060	3,468	3,447
Gulf Coast			4,041
Total Production	103,693	66,131	50,467
Oil Production *(Mbbl)*			
Appalachia	28	36	45
West Coast	2,803	2,834	2,628
Gulf Coast			187
Total Production	2,831	2,870	2,860

Average Prices

	Year Ended September 30		
	2013	2012	2011
Average Gas Price/Mcf			
Appalachia	$ 3.49	$ 2.71	$ 4.37
West Coast(1)	$ 6.61	$ 6.27	$ 7.63
Gulf Coast			$ 5.02
Weighted Average	$ 3.58	$ 2.89	$ 4.64
Weighted Average After Hedging(2)	$ 4.10	$ 4.42	$ 5.60
Average Oil Price/Barrel (bbl)			
Appalachia	$ 96.48	$ 93.94	$ 86.58
West Coast	$ 103.14	$ 107.13	$ 96.45
Gulf Coast			$ 88.57
Weighted Average	$ 103.07	$ 106.97	$ 95.78
Weighted Average After Hedging(2)	$ 98.21	$ 90.88	$ 81.13

(1) Prices for all periods presented reflect revenues from gas produced on the West Coast, including natural gas liquids. In previous years, natural gas liquids were reported as gas processing plant revenues as opposed to natural gas revenues.

(2) 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.

2013 Compared with 2012

Operating revenues for the Exploration and Production segment increased $144.8 million in 2013 as compared with 2012. Gas production revenue after hedging increased $132.4 million primarily due to production increases in the Appalachian division. The increase in Appalachian production was primarily due to increased development within the Marcellus Shale formation, primarily in Lycoming County, Pennsylvania. This was partially offset by a $0.32 per Mcf decrease in the weighted average price of gas after hedging. Oil production revenue after hedging increased $17.2 million due to an increase in the weighted average price of oil after hedging ($7.33 per Bbl). Oil production was slightly lower year over year, largely the result of a continued constraint in a third-party pipeline used to transport natural gas production within the Sespe Field. The constraint on natural gas transportation capacity impacts oil production in that natural gas is a byproduct of the Exploration and Production segment s oil production at the Sespe Field. The decrease in other revenue ($4.5 million) was largely due to a $3.7 million mark-to-market charge related to hedging ineffectiveness associated with certain crude oil hedges.

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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.

2012 Compared with 2011

Operating revenues for the Exploration and Production segment increased $39.1 million in 2012 as compared with 2011. Gas production revenue after hedging increased $9.7 million primarily due to production increases in the Appalachian division, partially offset by decreases in Gulf Coast production. The increase in Appalachian production was primarily due to increased development within the Marcellus Shale formation, primarily in Tioga County, Pennsylvania, with additional Marcellus Shale production from Lycoming County, Pennsylvania. The decrease in Gulf Coast gas production resulted from the sale of the Exploration and Production segment s off-shore oil and natural gas properties in April 2011. Increases in natural gas production were partially offset by a $1.18 per Mcf decrease in the weighted average price of gas after hedging. Oil production revenue after hedging increased $28.8 million due to an increase in the weighted average price of oil after hedging ($9.75 per Bbl). Oil production was largely flat year over year, as increased oil production from West Coast properties was largely offset by the decrease in this segment s off-shore oil production as a result of the aforementioned sale.

Earnings

2013 Compared with 2012

The Exploration and Production segment s earnings for 2013 were $115.4 million, compared with earnings of $96.5 million for 2012, an increase of $18.9 million. The main drivers of the increase were higher natural gas production ($107.9 million) and higher crude oil prices after hedging ($13.5 million). In addition, there was a decrease in property and other taxes ($4.2 million) which largely reflects the non-recurrence of a $4.0 million natural gas impact fee accrual recorded during the quarter ended March 31, 2012 related to Marcellus Shale wells drilled prior to fiscal 2012, as discussed below. These earnings increases were partially offset by the earnings impact of higher depletion expense ($36.3 million), lower natural gas prices after hedging ($21.8 million), higher production costs ($23.3 million), higher general, administrative and other expense ($9.0 million), higher interest expense ($6.8 million), higher income taxes ($4.0 million), a derivative mark-to-market charge ($2.7 million) and lower crude oil production ($2.3 million). The increase in depletion expense is primarily due to increased Appalachian natural gas production (primarily in the Marcellus Shale formation). The increase in production costs was largely attributable to higher transportation costs. In addition, compression and water disposal costs in the Appalachian region coupled with higher well repair, maintenance and labor costs in the West Coast region led to further increases in production costs. The increase in general, administrative and other expense was largely due to an increase in personnel costs. The increase in interest expense was attributable to an increase in the weighted average amount of debt due to the Exploration and Production segment s share of both the Company s $500 million long-term debt issuance in February 2013 and the Company s $500 million long-term debt issuance in December 2011. The increase in income tax expense is largely attributable to higher state income taxes.

2012 Compared with 2011

The Exploration and Production segment s earnings for 2012 were $96.5 million, compared with earnings of $124.2 million for 2011, a decrease of $27.7 million. The main drivers of the decrease were lower natural gas prices after hedging in the Appalachian and West Coast regions ($51.1 million), lower Gulf Coast natural gas and crude oil revenues as a result of this segment s sale of its off-shore oil and natural gas properties in 2011 ($25.2 million), and higher depletion expense ($26.5 million). In addition, higher interest expense ($7.3 million), higher production costs ($6.6 million), higher property and other taxes ($7.4 million), higher income taxes ($3.2 million), and higher general, administrative and other expenses ($2.7 million) further reduced earnings. The increase in depletion expense is primarily due to an increase in depletable base (largely due to increased capital spending in the Appalachian region, specifically related to the development of Marcellus Shale properties) and increased Appalachian natural gas production (primarily in the Marcellus Shale formation). The increase in interest expense was attributable to an increase in the weighted average amount of debt (due to the Exploration and Production segment s share ($470 million) of the $500 million long-term debt issuance in December 2011). The increase in lease operating expense is largely attributable to higher transportation, compression costs, water disposal, equipment rental and repair costs in the Appalachian region. The increase in property and other taxes was largely due to the accrual of a new impact fee imposed by Pennsylvania in 2012. In February 2012, the Commonwealth of Pennsylvania passed legislation that includes a natural gas impact fee. The legislation, which covers essentially all of Seneca s Marcellus Shale wells, imposes an annual fee for a period of 15 years on each well drilled. The per well impact fee is adjusted annually based on three factors: the age of the well, changes in the Consumer Price Index and the average monthly NYMEX price for natural gas. The fee is retroactive and applied to wells drilled in the current fiscal year and in all previous years. The impact fee increased property, franchise and other taxes in 2012 by $9.0 million, of which $4.0 million related to wells drilled prior to 2012. The increase in income taxes was largely due to higher state income taxes, which was largely the result of a larger percentage of production in higher state income tax jurisdictions in 2012 as compared to 2011. Higher personnel costs led to increases in general, administrative and other operating expenses. These earnings decreases were partially offset by higher natural gas production of $71.8 million, as well as higher crude oil prices and crude oil production of $19.1 million and $10.3 million, respectively (all amounts exclude the impact of the 2011 sale of Gulf Coast properties). Higher interest income of $0.6 million also benefitted earnings. The increase in interest income was largely due to higher money market investment balances.

ENERGY MARKETING

Revenues

Energy Marketing Operating Revenues

	Year Ended September 30		
	2013	2012	2011
		(Thousands)	
Natural Gas (after Hedging)	$ 213,324	$ 187,969	$ 284,916
Other	50	35	50
	$ 213,374	$ 188,004	$ 284,966

Energy Marketing Volume

	Year Ended September 30		
	2013	2012	2011
Natural Gas (MMcf)	46,875	45,756	52,893

2013 Compared with 2012

Operating revenues for the Energy Marketing segment increased $25.4 million in 2013 as compared with 2012. The increase reflects an increase in gas sales revenue due to a higher average price of natural gas as well as an increase in volume sold due to colder weather.

2012 Compared with 2011

Operating revenues for the Energy Marketing segment decreased $97.0 million in 2012 as compared with 2011. The decrease reflected a decline in gas sales revenue due to a lower average price of natural gas and a decrease in volume sold. Much warmer weather was primarily responsible for the decrease in volume sold.

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Earnings

2013 Compared with 2012

The Energy Marketing segment s earnings in 2013 were $4.6 million, an increase of $0.4 million when compared with earnings of $4.2 million in 2012. This increase in earnings was largely attributable to higher margin of $0.5 million, primarily driven by an increase in the benefit the Energy Marketing segment derived from its contracts for storage capacity.

2012 Compared with 2011

The Energy Marketing segment s earnings in 2012 were $4.2 million, a decrease of $4.6 million when compared with earnings of $8.8 million in 2011. This decrease was largely attributable to a decline in margin of $4.5 million, primarily driven by lower volume sold to retail customers as well as a reduction in the benefit the Energy Marketing segment derived from its contracts for storage capacity.

GATHERING

Revenues

Gathering Operating Revenues

	Year Ended September 30		
	2013	2012	2011
		(Thousands)	
Gathering	$ 33,815	$ 16,771	$ 10,017
Processing Revenues	966	704	1,234
	$ 34,781	$ 17,475	$ 11,251

Gathering Volume (MMcf)

	Year Ended September 30		
	2013	2012	2011
Gathered Volume	93,598	48,562	29,988

2013 Compared with 2012

Operating revenues for the Gathering segment increased $17.3 million in 2013 as compared with 2012 largely due to an increase in gathering revenues driven by a 45.0 Bcf increase in gathered volume. This increase was primarily due to Midstream Corporation s Trout Run Gathering System (Trout Run) which was placed in service in May 2012 and the expansion of Midstream Corporation s Covington Gathering System (Covington). Trout Run and Covington provide gathering services for Seneca s production.

2012 Compared with 2011

Operating revenues for the Gathering segment increased $6.2 million in 2012 as compared with 2011 primarily due to an increase in gathering revenues driven by an 18.6 Bcf increase in gathered volume. The increase was primarily due to the growth in Seneca s Marcellus Shale production at Covington in Tioga County, Pennsylvania and Trout Run in Lycoming County, Pennsylvania. Trout Run was placed in service in May 2012, as discussed above.

Earnings

2013 Compared with 2012

The Gathering segment s earnings in 2013 were $13.3 million, an increase of $6.4 million when compared with earnings of $6.9 million in 2012. The increase in earnings is due to higher gathering and processing revenues ($11.2 million). This was partially offset by higher operating expenses ($1.5 million), higher depreciation expense ($1.5 million), higher income tax expense ($1.3 million), and higher interest expense ($0.5 million). The completion of Trout Run and the expansion of Covington are primarily responsible for the revenue, operating expense and depreciation expense variations. The increase in income tax expense was largely due to higher state taxes and a true-up adjustment related to the filed federal return. The increase in interest expense was due to an increase in the weighted average amount of debt due to the Gathering segment s share of both the Company s $500 million long-term debt issuance in February 2013 and the Company s $500 million long-term debt issuance in December 2011.

2012 Compared with 2011

The Gathering segment s earnings in 2012 were $6.9 million, an increase of $2.0 million when compared with earnings of $4.9 million in 2011. The increase in earnings is due to higher gathering revenues ($4.0 million). This was partially offset by higher operating expenses ($0.4 million), higher depreciation expense ($0.7 million), and higher interest expense ($0.9 million). Continued production growth at Covington and the completion of Trout Run in May 2012 are the primary reasons for the revenue, operating expense and depreciation expense variations. The increase in interest expense was due to an increase in the weighted average amount of debt due to the Gathering segment s share of the Company s $500 million long-term debt issuance in December 2011.

ALL OTHER AND CORPORATE OPERATIONS

All Other and Corporate operations primarily includes the operations of Seneca s Northeast Division, Highland (which was merged into Seneca s Northeast Division in June 2011) and corporate operations. Seneca s Northeast Division markets timber from its New York and Pennsylvania land holdings. In September 2012, the Company recorded an impairment charge ($1.1 million) to write-off the remaining value of Horizon Power s investment in ESNE, a dormant 80-megawatt, combined cycle, natural gas-fired power plant in North East, Pennsylvania. In February 2011, Horizon Power sold its 50% equity method investments in Seneca Energy and Model City for $59.4 million. Seneca Energy and Model City generated and sold electricity using methane gas obtained from landfills owned by outside parties. The sale is the result of the Company s strategy to pursue the sale of smaller, non-core assets in order to focus on its core businesses, including the development of the Marcellus Shale and the expansion of its pipeline business throughout the Appalachian region.

Earnings

2013 Compared with 2012

All Other and Corporate operations recorded a loss of $2.2 million in 2013, which was $4.4 million lower than the loss of $6.6 million in 2012. The decrease in loss was primarily due to lower income tax expense of $3.4 million (primarily due to an intercompany deferred tax reallocation), lower property, franchise and other taxes of $1.8 million (largely due to a reduction in New York State capital stock tax) and a reduction in loss from unconsolidated subsidiaries of $0.8 million (as noted above, a $1.1 million impairment charge was recorded in September 2012 that did not recur in 2013). This was partially offset by higher operating costs of $1.2 million (largely due to higher personnel costs).

2012 Compared with 2011

All Other and Corporate operations recorded a loss of $6.6 million in 2012, a decrease of $32.4 million when compared with earnings of $25.8 million in 2011. The decrease in earnings was primarily due to the gain recorded on the sale of Horizon Power s investments in Seneca Energy and Model City of $31.4 million during the quarter ended March 31, 2011 that did not recur in 2012. In addition, lower income from unconsolidated subsidiaries of $0.4 million further decreased earnings.

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 increased $8.3 million in 2013 as compared to 2012. This increase is due to a higher average amount of long-term debt outstanding partially offset by a decrease in the weighted average interest rate on such debt. The Company issued $500 million of 3.75% notes in February 2013 and repaid $250 million of 5.25% notes that matured in March 2013. In addition, there was a decrease in capitalized interest associated with decreased Exploration and Production segment capital expenditures in the Appalachian region, which increased interest expense in comparison to the prior year.

Interest on long-term debt increased $8.4 million in 2012 as compared to 2011. This increase was primarily the result of a higher average amount of long-term debt outstanding. The Company issued $500 million of notes at 4.90% in December 2011 and repaid $150 million of 6.70% notes that matured in November 2011. This was partially offset by an increase in capitalized interest associated with increased Exploration and Production segment capital expenditures in the Appalachian region, which decreased interest expense in comparison to the prior year.

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		
	2013	2012	2011
		(Millions)	
Provided by Operating Activities	$ 738.6	$ 659.0	$ 654.0
Capital Expenditures	(703.5)	(1,035.0)	(814.3)
Net Proceeds from Sale of Unconsolidated Subsidiaries			59.4
Net Proceeds from Sale of Oil and Gas Producing Properties			63.5
Other Investing Activities	(2.5)	0.5	(2.9)
Reduction of Long-Term Debt	(250.0)	(150.0)	(200.0)
Change in Notes Payable to Banks and Commercial Paper	(171.0)	131.0	40.0
Net Proceeds from Issuance of Long-Term Debt	495.4	496.1	
Net Proceeds from Issuance (Repurchase) of Common Stock	5.4	10.3	(0.6)
Dividends Paid on Common Stock	(122.7)	(118.8)	(114.6)
Excess Tax (Costs) Benefits Associated with Stock-Based Compensation Awards	0.7	1.0	(1.2)
Net Decrease in Cash and Temporary Cash Investments	$ (9.6)	$ (5.9)	$ (316.7)

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OPERATING CASH FLOW

Internally generated cash from operating activities consists of net income available for common stock, adjusted for non-cash expenses, non-cash income and changes in operating assets and liabilities. Non-cash items include depreciation, depletion and amortization, deferred income taxes and the elimination of an other post-retirement regulatory liability. Net income available for common stock is also adjusted for the gain on sale of unconsolidated subsidiaries.

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 $738.6 million in 2013, an increase of $79.6 million compared with the $659.0 million provided by operating activities in 2012. The increase in cash provided by operating activities reflects higher cash provided by operating activities in the Exploration and Production segment and Pipeline and Storage segment, partly offset by lower cash provided by operating activities in the Utility segment. The increase in the Exploration and Production segment is primarily due to higher cash receipts from natural gas production in the Appalachian region, partially offset by a decrease in cash provided by operating activities from hedging collateral account fluctuations and higher federal and state income tax payments. The increase in the Pipeline and Storage segment is due to higher cash receipts from transportation revenues as a result of expansion projects coming on-line and higher tariff rates from the implementation of Supply Corporation s rate case proceeding, as discussed above. The decrease in the Utility segment can be attributed to the timing of gas cost recovery and the timing of receivable collections. The winter of 2012 was substantially warmer than normal, resulting in lower receivable balances at September 30, 2012 that were collected in subsequent months. The winter of 2013 saw more normal temperatures, resulting in higher receivable balances at September 30, 2013 that will be collected in subsequent months.

Net cash provided by operating activities totaled $659.0 million in 2012, an increase of $5.0 million compared with the $654.0 million provided by operating activities in 2011. The increase in cash provided by operating activities is primarily due to an increase in cash provided by operations in the Utility segment related to the timing of gas cost recovery. Partly offsetting this increase in cash provided by operating activities, the Exploration and Production segment experienced a decrease in cash provided by operating activities due to the loss of cash flows from the Company s former oil and natural gas properties in the Gulf of Mexico and the non-recurrence of federal tax refunds in fiscal 2011, partially offset by increases in cash provided by operating activities from hedging collateral account fluctuations and higher cash receipts from oil and natural gas production in the West Coast and Appalachian regions.

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INVESTING CASH FLOW

Expenditures for Long-Lived Assets

The Company s expenditures for long-lived assets totaled $717.1 million, $977.4 million and $854.2 million in 2013, 2012 and 2011, respectively. These amounts include accounts payable and accrued liabilities related to capital expenditures and will differ from capital expenditures shown on the Consolidated Statement of Cash Flows. Capital expenditures recorded as liabilities are excluded from the Consolidated Statement of Cash Flows. They are included in subsequent Consolidated Statement of Cash Flows when they are paid. The table below presents these expenditures:

	Year Ended September 30		
	2013	2012 (Millions)	2011
Utility:			
Capital Expenditures	$ 72.0(1)	$ 58.3(2)	$ 58.4(3)
Pipeline and Storage:			
Capital Expenditures	56.1(1)	144.2(2)	129.2(3)
Exploration and Production:			
Capital Expenditures	533.1(1)	693.8(2)	648.8(3)
Gathering:			
Capital Expenditures	54.8(1)	80.0(2)	17.0(3)
All Other and Corporate:			
Capital Expenditures	1.1	1.1	0.8
Total Expenditures	$ 717.1	$ 977.4	$ 854.2

(1) 2013 capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $58.5 million, $5.6 million, $6.7 million and $10.3 million, respectively, of accounts payable and accrued liabilities related to capital expenditures.

(2) 2012 capital expenditures for the Exploration and Production segment, Pipeline and Storage segment, the Gathering segment and the Utility segment include $38.9 million, $12.7 million, $12.7 million and $3.2 million, respectively, of accounts payable and accrued liabilities related to capital expenditures.

(3) 2011 capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment, the Gathering segment and the Utility segment include $103.3 million, $16.4 million, $3.1 million and $2.3 million, respectively, of accounts payable and accrued liabilities related to capital expenditures.

Utility

The majority of the Utility segment s capital expenditures for 2013, 2012 and 2011 were made for replacement of mains and main extensions and for the replacement of service lines. The capital expenditures for 2013 include $9.1 million related to the planned replacement of the Utility segment s legacy mainframe systems.

Pipeline and Storage

The majority of the Pipeline and Storage segment s capital expenditures for 2013 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 2013 include expenditures for the construction of Supply Corporation s Northern Access expansion project ($14.5 million), Supply Corporation s Line N 2012 Expansion Project ($4.2 million), Supply Corporation s Line N 2013 Project ($2.8 million) and Supply Corporation s Mercer Expansion Project ($0.7 million), as discussed below.

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The majority of the Pipeline and Storage segment s capital expenditures for 2012 were related to the construction of Supply Corporation s Northern Access expansion project ($50.8 million), Supply Corporation s Line N 2012 Expansion Project ($30.5 million), Empire s Tioga County Extension Project ($24.1 million) and Supply Corporation s Line N Expansion Project ($2.9 million). The Pipeline and Storage segment capital expenditures for 2012 also include additions, improvements, and replacements to this segment s transmission and gas storage systems.

The majority of the Pipeline and Storage segment s capital expenditures for 2011 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 2011 include expenditures for the construction of Empire s Tioga County Extension Project ($31.8 million), Supply Corporation s Line N Expansion Project ($18.1 million) and Supply Corporation s Lamont Phase II Project ($8.1 million).

Exploration and Production

In 2013, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $428.5 million for the Appalachian region (including $393.3 million in the Marcellus Shale area) and $104.6 million for the West Coast region. These amounts included approximately $148.5 million spent to develop proved undeveloped reserves.

In 2012, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $630.9 million for the Appalachian region (including $567.9 million in the Marcellus Shale area) and $62.9 million for the West Coast region. These amounts included approximately $216.6 million spent to develop proved undeveloped reserves. The capital expenditures in the West Coast region include the Company s establishment of a position within the Mississippian Lime crude oil play for approximately $6.2 million in August 2012, including approximately 9,300 net acres in Pratt County, Kansas. Seneca is now the operator on 4,600 net acres and has a non-operating interest on the remaining net acreage position.

In 2011, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $595.8 million for the Appalachian region (including $585.1 million in the Marcellus Shale area), $47.4 million for the West Coast region and $5.6 million for the Gulf Coast region (former off-shore oil and natural gas properties in the Gulf of Mexico). These amounts included approximately $199.2 million spent to develop proved undeveloped reserves. The capital expenditures in the Appalachian region included the Company s acquisition of oil and gas properties in the Covington Township area of Tioga County, Pennsylvania from EOG Resources, Inc. for approximately $24.1 million in November 2010.

In April 2011, the Company completed the sale of its off-shore oil and natural gas properties in the Gulf of Mexico. The Company received net proceeds of $55.4 million from this sale. 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.

In May 2011, the Company sold the Sprayberry property that was accounted for in its West Coast region for $8.1 million. 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.

Gathering

The majority of the Gathering segment s capital expenditures for 2013 were related to the expansion of Midstream Corporation s Trout Run Gathering System ($48.0 million).

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The majority of the Gathering segment s capital expenditures for 2012 were related to the construction of Midstream Corporation s Trout Run Gathering System ($64.5 million) and the expansion of Midstream Corporation s Covington Gathering System ($12.2 million).

The majority of the Gathering segment s capital expenditures for 2011 were related to the construction of Midstream Corporation s Trout Run Gathering System ($15.4 million) and the expansion of Midstream Corporation s Covington Gathering System ($1.6 million).

Estimated Capital Expenditures

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

	Year Ended September 30		
	2014	2015 (Millions)	2016
Utility	$ 84.8	$ 87.7	$ 72.1
Pipeline and Storage	126.5	240.8	281.3
Exploration and Production(1)	634.8	728.3	823.1
Gathering	121.0	124.8	146.8
All Other	0.6	0.4	0.3
	$ 967.7	$ 1,182.0	$ 1,323.6

(1) Includes estimated expenditures for the years ended September 30, 2014, 2015 and 2016 of approximately $169 million, $246 million and $101 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.

Utility

Capital expenditures for the Utility segment in 2014 through 2016 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. Estimated capital expenditures in the Utility segment for 2014 through 2016 also include amounts for the replacement of its legacy mainframe systems.

Pipeline and Storage

Capital expenditures for the Pipeline and Storage segment in 2014 through 2016 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 are discussed below.

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

component of Property, Plant and Equipment on the Consolidated Balance Sheet. As of September 30, 2013, the total amount reserved for the Pipeline and Storage segment s preliminary survey and investigation costs was $7.8 million.

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

Supply Corporation has begun service under a transportation service agreement with Statoil Natural Gas LLC (Statoil) which provides 320,000 Dth per day of firm transportation capacity for a 20-year term in conjunction with Supply Corporation s Northern Access expansion project. This capacity provides Statoil with a firm transportation path from the Tennessee Gas Pipeline (TGP) 300 Line at Ellisburg and Transcontinental Pipeline at Leidy to the TransCanada Pipeline at Niagara. These receipt points are attractive because they provide routes for Marcellus Shale gas from the TGP 300 Line and Transco Leidy Line in northern Pennsylvania, to be transported from the Marcellus supply basin to northern markets. Supply Corporation received from the FERC its NGA Section 7(c) Certificate authorization of this project on October 20, 2011, and received its Notice to Proceed on April 13, 2012. The project facilities involve approximately 9,500 horsepower of additional compression at Supply Corporation s existing Ellisburg Station and a new approximately 5,000 horsepower compressor station in Wales, New York, along with other system enhancements including enhancements to the jointly owned Niagara Spur Loop Line. Initial service began on November 1, 2012, with full service implemented on January 16, 2013. As of September 30, 2013, approximately $68.4 million has been spent on the Northern Access Expansion Project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2013.

Supply Corporation has also begun service under three service agreements for a total of 163,000 Dth per day of additional capacity on Line N to TETCO at Holbrook (Line N 2012 Expansion Project). The FERC issued the NGA Section 7(c) Certificate on March 29, 2012 authorizing construction and operation of the Line N 2012 Expansion Project, which consists of an additional 20,620 horsepower of compression at its Buffalo Compressor Station, and the replacement of 4.85 miles of 20 pipe with 24 pipe, to enhance the integrity and reliability of its system and to create the additional capacity. On October 3, 2012, Supply Corporation put in service a portion of the Project facilities and began early interim service for Range Resources. It began full service for all Project shippers on November 1, 2012. As of September 30, 2013, approximately $37.1 million has been spent on the Line N 2012 Expansion Project for the incremental capacity and system replacement, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2013.

In 2011, Supply Corporation concluded an Open Season to increase its capability to move gas north on its Line N system and deliver gas to a new interconnection with Tennessee Gas Pipeline at Mercer, Pennsylvania, a pooling point recently established at Tennessee s Station 219 (Mercer Expansion Project). Supply Corporation has executed a precedent agreement with Range Resources for 105,000 Dth per day, all of the project capacity, for service expected to begin November 2014. The preliminary cost estimate is $30.4 million, of which $27.2 million is for expansion and $3.2 million is for system modernization. Supply Corporation expects to construct the required approximately 3,500 horsepower of compression at Mercer, and replace 2.08 miles of pipeline, all under its FERC blanket certificate authorization. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above, except for approximately $0.7 million already spent through September 30, 2013. The Company has determined that it is highly probable that this project will be built. Accordingly, previous reserves have been reversed and the project costs have been capitalized as Construction Work in Progress.

On April 11, 2012, Supply Corporation concluded an Open Season to increase its capacity to move gas south on its Line N system to TETCO at Holbrook (Line N 2013 Project). Supply Corporation has executed a service agreement with Shell Energy NA for 30,000 Dth per day, all of the project capacity, and service began on November 1, 2013. The estimated cost is $3.4 million. Supply Corporation replaced 1.27 miles of 20 pipeline with 24 pipeline under its FERC blanket certificate authorization. Approximately $2.8 million has been spent on the Line N 2013 Project through September 30, 2013, all of which has been capitalized as Construction Work in Progress. The remainder is expected to be spent in fiscal 2014 and is included as Pipeline and Storage estimated capital expenditures in the table above.

On January 18, 2013, Supply Corporation concluded an Open Season to further increase its capacity to move gas north and south on its Line N system to TETCO at Holbrook and TGP at Mercer (Westside Expansion and Modernization Project). Supply Corporation executed a precedent agreement for 145,000 Dth per day of the project capacity, for service expected to begin in 2015. A precedent agreement has been extended to one additional shipper for the remaining 30,000 Dth per day of Line N capacity. The Westside Expansion and Modernization Project facilities are expected to include the replacement of approximately 23.5 miles of 20 pipe with 24 pipe and the addition of approximately 3,600 horsepower of compression at Mercer. The preliminary cost estimate is $74 million, of which $39 million is related to expansion and the remainder is for replacement. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above. Approximately $0.2 million has been spent to study the Westside Expansion and Modernization Project through September 30, 2013. The Company has determined it is highly probable that the project will be built. Accordingly, previous reserves have been reversed and the project costs have been reestablished as a Deferred Charge on the Consolidated Balance Sheet.

On April 12, 2013, Supply Corporation concluded an Open Season to increase its capacity to move gas south on its Line N system by an expansion of the interconnection facilities to TETCO at Holbrook (Holbrook Expansion Project). Supply Corporation received requests for approximately 13,000 Dth per day of capacity, for service which began November 2, 2013. The preliminary cost estimate is $0.9 million. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above, except for approximately $0.2 million already spent through September 30, 2013, that has been capitalized as Construction Work in Progress.

Supply Corporation and TGP have been jointly developing a project that would combine expansions on both pipeline systems, providing a seamless transportation path from TGP s 300 Line in the Marcellus fairway to the TransCanada Pipeline delivery point at Niagara. Supply Corporation would offer 140,000 Dth per day of capacity on its system to TGP under a lease, from its Ellisburg Station for redelivery to TGP in East Eden, NY (Northern Access 2015). The Northern Access 2015 project would involve the construction of a new 15,400 horsepower compressor station in Hinsdale, NY and a 7,700 horsepower addition to its compressor station in Concord, NY, for service expected to commence in late 2015. Supply Corporation and TGP are currently negotiating the terms of the lease agreement, and TGP is negotiating a precedent agreement with an anchor shipper. The preliminary cost estimate for the Northern Access 2015 project is $67 million. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above. No significant amounts have been spent on this project through September 30, 2013.

On August 12, 2013, Empire concluded an Open Season, offering for the first time no-notice transportation and storage service to new and existing shippers on the Empire pipeline system. Rochester Gas & Electric (RG&E), Empire s largest LDC connected market, has executed a precedent agreement to convert all 172,500 Dth per day of its standard firm transportation services to no-notice service, including 3.3 Bcf of no-notice storage service. The new services will provide RG&E with a superior flexible delivery service with daily and seasonal load balancing capabilities and greater access to Marcellus supplies. The project would require Empire to construct a 17.2 mile, 20 pipeline and interconnection between Empire s pipeline system and Supply Corporation s system at Tuscarora, NY, and Supply Corporation to construct 1,500 horsepower of compression at its Tuscarora compressor station (Tuscarora Lateral Project). It is anticipated that Supply Corporation would provide Empire with the necessary storage services under a lease agreement. Empire and Supply Corporation began the FERC pre-filing process on April 12, 2013. The preliminary cost estimate for the Tuscarora Lateral Project is $56 million. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above. Approximately $0.2 million has been spent to study the Tuscarora Lateral Project through September 30, 2013. The Company has determined it is highly probable that the project will be built. Accordingly, previous reserves have been reversed and the project costs have been reestablished as a Deferred Charge on the Consolidated Balance Sheet.

Empire is developing an expansion of its system that would allow for the transportation of approximately 250,000 Dth per day of additional Marcellus supplies from Tioga County, Pennsylvania, to TransCanada Pipeline and the TGP 200 Line (Central Tioga County Extension). The connection to Supply Corporation afforded by the Tuscarora Lateral Project could allow those Marcellus supplies to be sourced on other parts of the Supply Corporation system in addition to, or instead of, Tioga County. Such a configuration would likely involve facility investments on the Supply Corporation system as well. The preliminary cost estimate for the Central Tioga County Extension is $150 million, and for a combined project involving Empire and Supply Corporation facilities the cost estimate is $250 million. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above. As of September 30, 2013, approximately $0.2 million has been spent to study the Central Tioga County Extension project, which has been included in preliminary survey and investigation charges and has been fully reserved for at September 30, 2013.

Exploration and Production

Estimated capital expenditures in 2014 for the Exploration and Production segment include approximately $530.1 million for the Appalachian region and $104.7 million for the West Coast region.

Estimated capital expenditures in 2015 for the Exploration and Production segment include approximately $612.1 million for the Appalachian region and $116.2 million for the West Coast region.

Estimated capital expenditures in 2016 for the Exploration and Production segment include approximately $722.9 million for the Appalachian region and $100.2 million for the West Coast region.

Gathering

The majority of the Gathering segment capital expenditures in 2014 through 2016 are expected to be for construction and expansion of gathering systems, as discussed below.

NFG Midstream Trout Run, LLC, a wholly owned subsidiary of Midstream Corporation, continues to develop its Trout Run Gathering System in Lycoming County, Pennsylvania. The Trout Run Gathering System was initially placed in service in May 2012. The current system consists of approximately 40 miles of backbone and in-field gathering system. The complete buildout will include in-field gathering pipelines and two compressor stations at a cost of approximately $215 million. As of September 30, 2013, the Company has spent approximately $128.0 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, 2013.

NFG Midstream Covington, LLC, a wholly owned subsidiary of Midstream Corporation, has been expanding its gathering system in Tioga County, Pennsylvania. As of September 30, 2013, the Company has spent approximately $28.3 million in costs related to the Covington gathering system. All costs associated with this gathering system are included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2013.

In addition, two other wholly owned subsidiaries of Midstream Corporation, NFG Midstream Mt. Jewett, LLC and NFG Midstream Tionesta, LLC have constructed gathering pipelines and interconnects. As of September 30, 2013, approximately $3.8 million has been spent on the NFG Midstream Mt. Jewett gathering system and approximately $2.2 million has been spent on the NFG Midstream Tionesta gathering system, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2013.

NFG Midstream Clermont, LLC, a wholly owned subsidiary of Midstream Corporation, plans to build an extensive gathering system with compression in the Pennsylvania counties of McKean, Elk and Cameron. Fiscal 2014 through 2016 capital spending on the Clermont gathering system will include trunkline and related facilities. As of September 30, 2013, approximately $3.4 million has been spent on the NFG Midstream Clermont gathering system, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2013.

Midstream Corporation is planning the construction of several other gathering systems. As of September 30, 2013, the Company has spent approximately $0.7 million in costs related to these projects, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2013.

Project Funding

The Company has been financing the Pipeline and Storage segment and Gathering segment projects mentioned above, as well as the Exploration and Production segment capital expenditures, with cash from operations and both short and long-term borrowings. The Company issued additional long-term debt in February 2013 to enhance its liquidity position. Going forward, while the Company expects to use cash from operations as the first means of financing these projects, it is expected that the Company will use short-term borrowings as necessary during fiscal 2014. The level of such short-term borrowings will depend upon the amounts of cash provided by operations, which, in turn, will likely be impacted by natural gas and crude oil prices combined with production from existing wells.

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

FINANCING CASH FLOW

Consolidated short-term debt decreased $171.0 million when comparing the balance sheet at September 30, 2013 to the balance sheet at September 30, 2012. The maximum amount of short-term debt outstanding during the year ended September 30, 2013 was $272.8 million. The Company used its $500.0 million long-term debt issuance in February 2013 to substantially reduce its short-term debt. While the Company did not have any outstanding commercial paper and short-term notes payable to banks at September 30, 2013, the Company continues to consider short-term debt an important source of cash for temporarily financing capital expenditures and investments in corporations and/or partnerships, gas-in-storage inventory, unrecovered purchased gas costs, margin calls on derivative financial instruments, exploration and development expenditures, other working capital needs and repayment of long-term debt. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt.

As for bank loans, the Company maintains a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under these lines of credit are made at competitive market rates. These credit lines, which totaled $335.0 million at September 30, 2013, are revocable at the option of the financial institutions and are reviewed on an annual basis. The Company anticipates that its uncommitted lines of credit generally will be renewed at amounts near current levels, or substantially replaced by similar lines.

The total amount available to be issued under the Company s commercial paper program is $300.0 million. At September 30, 2013, the commercial paper program was backed by a syndicated committed credit facility totaling $750.0 million, which commitment extends through January 6, 2017. Under the committed credit facility, the Company agreed that its debt to capitalization ratio would not exceed .65 at the last day of any fiscal quarter through January 6, 2017. At September 30, 2013, the Company s debt to capitalization ratio (as calculated under the facility) was .43. The constraints specified in the committed credit facility would have permitted an additional $2.42 billion in short-term and/or long-term debt to be outstanding (further limited by the indenture covenants discussed below) before the Company s debt to capitalization ratio exceeded .65.

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

Under the Company s existing indenture covenants, at September 30, 2013, the Company would have been permitted to issue up to a maximum of $1.6 billion in additional long-term unsecured indebtedness at then current market interest rates in addition to being able to issue new indebtedness to replace maturing debt. The Company s present liquidity position is believed to be adequate to satisfy known demands. However, if the Company were to experience a significant loss in the future (for example, as a result of an impairment of oil and gas properties), it is possible, depending on factors including the magnitude of the loss, that these indenture covenants would restrict the Company s ability to issue additional long-term unsecured indebtedness for a period of up to nine calendar months, beginning with the fourth calendar month following the loss. This would not at any time preclude the Company from issuing new indebtedness to replace maturing debt.

The Company s 1974 indenture pursuant to which $99.0 million (or 6.0%) of the Company s long-term debt (as of September 30, 2013) was issued, contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

The Company s $750.0 million committed credit facility also contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the committed credit facility. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $40.0 million or more or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $40.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of September 30, 2013, the Company did not have any debt outstanding under the committed credit facility.

The Company s embedded cost of long-term debt was 5.58% at September 30, 2013 and 6.17% at September 30, 2012. Refer to Interest Rate Risk in this Item for a more detailed breakdown of the Company s embedded cost of long-term debt.

The Company repaid $250.0 million of 5.25% notes that matured in March 2013, which had been classified as Current Portion of Long-Term Debt at September 30, 2012. None of the Company s long-term debt at September 30, 2013 will mature within the following twelve-month period.

On February 15, 2013, the Company issued $500.0 million of 3.75% notes due March 1, 2023. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $495.4 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 both a change in control and a ratings downgrade to a rating below investment grade. The proceeds of this debt issuance were used to refund the $250.0 million of 5.25% notes that matured in March 2013, as well as for general corporate purposes, including the reduction of short-term debt.

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On December 1, 2011, the Company issued $500.0 million of 4.90% notes due December 1, 2021. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $496.1 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 both a change in control and a ratings downgrade to a rating below investment grade. The proceeds of this debt issuance were used for general corporate purposes, including refinancing short-term debt that was used to pay the $150.0 million due at the maturity of the Company s 6.70% notes in November 2011.

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

OFF-BALANCE SHEET ARRANGEMENTS

The Company has entered into certain off-balance sheet financing arrangements. These financing arrangements are primarily operating leases. The Company s consolidated subsidiaries have operating leases, the majority of which are with the Exploration and Production segment and Corporate operations, having a remaining lease commitment of approximately $64.1 million. These leases have been entered into for the use of compressors, drilling rigs, buildings, meters and other items and are accounted for as operating leases.

CONTRACTUAL OBLIGATIONS

The following table summarizes the Company s expected future contractual cash obligations as of September 30, 2013, and the twelve-month periods over which they occur:

	Payments by Expected Maturity Dates						
	2014	2015	2016	2017 (Millions)	2018	Thereafter	Total
Long-Term Debt, including interest expense(1)	$ 91.9	$ 91.9	$ 91.9	$ 91.9	$ 383.0	$ 1,563.3	$ 2,313.9
Operating Lease Obligations	$ 34.4	$ 6.2	$ 6.1	$ 6.0	$ 5.8	$ 5.6	$ 64.1
Purchase Obligations:							
Gas Purchase Contracts(2)	$ 209.3	$ 26.4	$ 2.4	$	$	$	$ 238.1
Transportation and Storage Contracts	$ 48.1	$ 45.1	$ 48.7	$ 48.2	$ 26.3	$ 54.3	$ 270.7
Hydraulic Fracturing and Fuel Obligations	$ 13.8	$ 0.2	$ 0.2	$ 0.1	$	$	$ 14.3
Expansion Projects Related to Exploration and Production, Pipeline and Storage, and Gathering segments	$ 124.3	$	$	$	$	$	$ 124.3
Mainframe Replacement Project	$ 9.4	$ 17.3	$ 4.7	$	$	$	$ 31.4
Other	$ 39.7	$ 11.9	$ 8.0	$ 7.4	$ 6.8	$ 15.3	$ 89.1

(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.

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

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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 2013, the Company contributed $54.0 million to the Retirement Plan. The Company anticipates that the annual contribution to the Retirement Plan in 2014 will be in the range of $30.0 million to $40.0 million.

Changes in the discount rate, other actuarial assumptions, and asset performance could ultimately cause the Company to fund larger amounts to the Retirement Plan in 2014 in order to be in compliance with the Pension Protection Act of 2006 (as impacted by the Moving Ahead for Progress in the 21st Century Act). In July 2012, the Surface Transportation Extension Act, which is also referred to as the Moving Ahead for Progress in the 21st Century Act (the Act), was passed by Congress and signed by the President. The Act included pension funding stabilization provisions. The Company is continually evaluating its future contributions in light of the provisions of the Act. 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 short-term borrowings or through cash from operations.

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 401(h) accounts over the last several years and anticipates that it will continue making contributions to the VEBA trusts and 401(h) accounts. During 2013, the Company contributed $18.1 million to its VEBA trusts and 401(h) accounts. The Company anticipates that the annual contribution to its VEBA trusts and 401(h) accounts in 2014 will be in the range of $5.0 million to $15.0 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, 2013 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. Certain provisions of the Dodd-Frank Act related to derivatives became effective July 16, 2011, but other provisions related to derivatives have or will become effective as federal agencies (including the CFTC, various banking regulators and the SEC) adopt rules to implement the law. Among other things, the Dodd-Frank Act (1) regulates certain participants in the swaps markets, including new entities defined as swap dealers and major swap participants, (2) requires clearing and exchange-trading of certain swaps that the CFTC determines must be cleared, (3) requires reporting and recordkeeping of swaps, and (4) enhances the CFTC s enforcement authority, including the authority to establish position limits on derivatives and increases penalties for violations of the Commodity Exchange Act. For purposes of the Dodd-Frank Act, under rules adopted by the SEC and/or CFTC, the Company believes that it qualifies as a non-financial end user of derivatives, that is, as a non-financial entity that uses derivatives to hedge or mitigate commercial risk. Nevertheless, other rules that are being developed could have a significant impact on the Company. For example, banking regulators have proposed a rule that would require swap dealers and major swap participants subject to their jurisdiction to collect initial and variation margin from counterparties that are non-financial end users, though such swap dealers and major swap participants would have the discretion to set thresholds for posting margin (unsecured credit limits). Regardless of the levels of margin that might be required, concern remains that swap dealers and major swap participants will pass along their increased costs through higher transaction costs and prices, and reductions in thresholds for posting margin. In addition, while the Company expects to be exempt from the Dodd-Frank Act s requirement that swaps be cleared and traded on exchanges or swap execution facilities, the cost of entering into a non-exchange cleared swap that is available as an exchange cleared swap may be greater. The Dodd-Frank Act may also increase costs for derivative recordkeeping, reporting, position limit compliance, and other compliance; cause parties to materially alter the terms of derivative contracts; cause parties to restructure certain derivative contracts; reduce the availability of derivatives to protect against risks that the Company encounters or to optimize assets; reduce the Company s ability to monetize or restructure existing derivative contracts; and increase the Company s exposure to less creditworthy counterparties, all of which could increase the Company s business costs. The Company continues to monitor these developments but cannot predict the impact the Dodd-Frank Act may ultimately have on its operations.

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

The Company uses the crude oil swaps classified as Level 3 to hedge against the risk of declining commodity prices and not as speculative investments. Gains or losses related to these Level 3 derivative net liabilities (including any reduction for credit risk) are deferred until the hedged commodity transaction occurs in accordance with the provisions of the existing guidance for derivative instruments and hedging activities. The Level 3 derivative net liabilities amount to $5.2 million at September 30, 2013 and represent 3.7% of the Total Net Assets shown in Item 8 at Note F Fair Value Measurements at September 30, 2013.

The decrease in the net fair value liability of the Level 3 positions from October 1, 2012 to September 30, 2013, as shown in Item 8 at Note F, was attributable to a decrease in the commodity price of crude oil relative to the swap prices during that period. The Company believes that these fair values reasonably represent the amounts that the Company would realize upon settlement based on commodity prices that were present at September 30, 2013.

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The accounting rules for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At September 30, 2013, the Company determined that nonperformance risk would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty (for an asset) or the Company s (for a liability) credit default swaps rates.

The 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, 2013. At September 30, 2013, the Company had not entered into any natural gas or crude oil price swap agreements extending beyond 2018.

Natural Gas Price Swap Agreements

	Expected Maturity Dates					
	2014	**2015**	**2016**	**2017**	**2018**	**Total**
Notional Quantities (Equivalent Bcf)	76.6	52.6	40.4	38.9	5.3	213.8
Weighted Average Fixed Rate (per Mcf)	$ 4.27	$ 4.28	$ 4.35	$ 4.45	$ 4.81	$ 4.33
Weighted Average Variable Rate (per Mcf)	$ 3.85	$ 4.09	$ 4.17	$ 4.30	$ 4.60	$ 4.07

Of the total Bcf above, 0.5 Bcf is accounted for as fair value hedges at a weighted average fixed rate of $4.74 per Mcf. The remaining 213.3 Bcf are accounted for as cash flow hedges at a weighted average fixed rate of $4.34 per Mcf.

Crude Oil Price Swap Agreements

	Expected Maturity Dates					
	2014	**2015**	**2016**	**2017**	**2018**	**Total**
Notional Quantities (Equivalent Bbls)	1,968,000	1,056,000	900,000	300,000	75,000	4,299,000
Weighted Average Fixed Rate (per Bbl)	$ 100.22	$ 94.95	$ 91.77	$ 91.55	$ 91.00	$ 96.39
Weighted Average Variable Rate (per Bbl)	$ 104.06	$ 95.11	$ 91.30	$ 91.55	$ 90.32	$ 98.08

At September 30, 2013, the Company would have received from its respective counterparties an aggregate of approximately $54.7 million to terminate the natural gas price swap agreements outstanding at that date. The Company would have to pay its respective counterparties an aggregate of approximately $7.3 million to terminate the crude oil price swap agreements outstanding at September 30, 2013.

At September 30, 2012, the Company had natural gas price swap agreements covering 133.9 Bcf at a weighted average fixed rate of $4.37 per Mcf. The Company also had crude oil price swap agreements covering 2,316,000 Bbls at a weighted average fixed rate of $94.24 per Bbl.

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, 2013, the Company did not hold any futures contracts with maturity dates extending beyond 2017.

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Futures Contracts

	Expected Maturity Dates				
	2014	2015	2016	2017	Total
Net Contract Volume Purchased (Sold) (Equivalent Bcf)	(1)	0.8	0.5	0.1	1.4
Weighted Average Contract Price (per Mcf)	$ 4.20	$ 4.46	$ 4.60	$ 4.59	$ 4.25
Weighted Average Settlement Price (per Mcf)	$ 4.14	$ 4.44	$ 4.59	$ 4.65	$ 4.20

(1) The Energy Marketing segment has long (purchased) contracts covering 6.6 Bcf of gas and short (sold) contracts covering 6.6 Bcf of gas in 2014.

At September 30, 2013, the Company had long (purchased) contracts covering 8.7 Bcf of gas extending through 2017 at a weighted average contract price of $4.19 per Mcf and a weighted average settlement price of $4.02 per Mcf. Of this amount, 8.2 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 0.5 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 $1.5 million to terminate these contracts at September 30, 2013.

At September 30, 2013, the Company had short (sold) contracts covering 7.3 Bcf of gas extending through 2016 at a weighted average contract price of $4.33 per Mcf and a weighted average settlement price of $4.00 per Mcf. Of this amount, 6.4 Bcf is accounted for as cash flow hedges as these contracts relate to the anticipated sale of natural gas by the Energy Marketing segment. The remaining 0.9 Bcf is accounted for as fair value hedges 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 $2.4 million to terminate these contracts at September 30, 2013.

At September 30, 2012, the Company had long (purchased) contracts covering 8.7 Bcf of gas extending through 2016 at a weighted average contract price of $3.97 per Mcf and a weighted average settlement price of $4.01 per Mcf.

At September 30, 2012, the Company had short (sold) contracts covering 6.8 Bcf of gas extending through 2016 at a weighted average contract price of $4.10 per Mcf and a weighted average settlement price of $3.92 per Mcf.

The Company may be exposed to credit risk on any of the derivative financial instruments that are in a gain position. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check, and then on a quarterly basis monitors counterparty credit exposure. The majority of the Company s counterparties are financial institutions and energy traders. The Company has over-the-counter swap positions with thirteen counterparties of which eleven are in a net gain position. On average, the Company had $4.4 million of credit exposure per counterparty in a gain position at September 30, 2013. The maximum credit exposure per counterparty in a gain position at September 30, 2013 was $8.1 million. As of September 30, 2013, the Company had not received any collateral from the counterparties. 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, 2013, eleven of the thirteen counterparties to the Company s outstanding derivative instrument contracts (specifically the over-the-counter swaps) had a common credit-risk related contingency feature. In the event the Company s credit rating increases or falls below a certain threshold (applicable debt ratings), the available credit extended to the Company would either increase or decrease. A decline in the Company s credit rating, in and of itself, would not cause the Company to be required to increase the level of

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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, 2013, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $34.7 million according to the Company s internal model (discussed in Item 8 at Note F Fair Value Measurements). At September 30, 2013, the fair market value of the derivative financial instrument liabilities with a credit-risk related contingency feature was $0.6 million according to the Company s internal model (discussed in Item 8 at Note F Fair Value Measurements). For its over-the-counter swap agreements, the Company was not required to post any hedging collateral deposits at September 30, 2013.

For its exchange traded futures contracts, which are in an asset position, the Company was required to post $1.1 million in hedging collateral deposits as of September 30, 2013. As these are exchange traded futures contracts, there are no specific credit-risk related contingency features. The Company posts hedging collateral based on open positions and margin requirements it has with its counterparties.

The Company s requirement to post hedging collateral deposits 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 Item 8 at Note A under Hedging Collateral Deposits.

Interest Rate Risk

The fair value of long-term fixed rate debt is $1.8 billion at September 30, 2013. 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 (Dollars in millions)						
	2014	**2015**	**2016**	**2017**	**2018**	**Thereafter**	**Total**
Long-Term Fixed Rate Debt	$	$	$	$	$ 300.0	$ 1,349.0	$ 1,649.0
Weighted Average Interest Rate Paid					6.5%	5.4%	5.6%

RATE AND REGULATORY MATTERS

Utility Operation

Delivery rates for both the New York and Pennsylvania divisions are regulated by the states respective public utility commissions and typically are changed only when approved through a procedure known as a rate case. Although neither division has a rate case on file, see below for a description of other rate proceedings affecting the New York division. In both jurisdictions, delivery rates do not reflect the recovery of purchased gas costs. Prudently-incurred gas costs are recovered through operation of automatic adjustment clauses, and are collected primarily through a separately-stated supply charge on the customer bill.

New York Jurisdiction

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

Following discussions with regulatory staff with respect to earnings levels, on March 27, 2013, Distribution Corporation filed a plan (Plan) with the NYPSC proposing to adopt an earnings stabilization and sharing mechanism that would allocate earnings above a rate of return on equity of 9.96% evenly between shareholders and an accounting reserve (Reserve). The Reserve would be utilized to stabilize Distribution Corporation s earnings and to fund customer benefit programs. The Plan also proposed to increase capital spending and to aid new customer system expansion efforts. Discussions were held with NYPSC staff and others with respect to the Plan.

In a related development, on April 19, 2013, the NYPSC issued an order directing Distribution Corporation to either agree to make its rates and charges temporary subject to refund effective June 1, 2013, or show cause why its gas rates and charges should not be set on a temporary basis subject to refund (Order). The Order recognized Distribution Corporation s Plan and, while acknowledging the Company s cost-cutting and efficiency achievements, determined nonetheless that the Plan did not propose to adjust existing rates . . . enough to compensate for the imbalance between ratepayer and shareholder interests that has developed since . . . 2007 . . . Pursuant to the Order, the NYPSC commenced a temporary rate proceeding and, following hearings, on June 14, 2013, the NYPSC issued an order (Temporary Rates Order) making Distribution Corporation s rates and charges temporary and subject to refund pending the determination of permanent gas rates through further rate proceedings. Discussions for settlement of Distribution Corporation s rates and charges were commenced and are expected to continue as the formal case to establish permanent rates proceeds along a parallel path. The Consolidated Balance Sheet at September 30, 2013 reflects a $7.5 million ($4.9 million after-tax) refund provision in anticipation of a potential settlement.

In addition to authorizing a temporary rate proceeding, the Order also suggested an examination of the applicability of a provision of New York public utility law, PSL §66(20), that provides the NYPSC with stated authority to direct a refund of revenues received by a utility in excess of its authorized rate of return for a period of twelve months. On May 17, 2013, Distribution Corporation commenced an action in New York Supreme Court, Erie County, seeking the court s declaration that PSL §66(20) is unconstitutional. On October 25, 2013, the court dismissed Distribution Corporation s complaint without prejudice to recommence the action after a decision is rendered in the rate proceeding before the NYPSC. In addition, on September 25, 2013, Distribution Corporation commenced an appeal in New York Supreme Court, Albany County, seeking to annul the Temporary Rates Order on various grounds. Distribution Corporation is unable to predict the outcome of the administrative or judicial proceedings at this time.

Pennsylvania Jurisdiction

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

Pipeline and Storage

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

Empire also has no rate case currently on file with the FERC, but is not subject to any requirement to make any future general rate filing. Empire is also not barred from filing a general rate case at any time.

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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 policies and procedures. 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, 2013, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites will be approximately $14.7 million. This estimated liability has been recorded in Other Deferred Credits on the Consolidated Balance Sheet at September 30, 2013. The Company expects to recover its environmental clean-up costs through rate recovery. Other than as discussed in Note I (referred to below), 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 adversely impact the Company.

For further discussion refer to Item 8 at Note I Commitments and Contingencies under the heading Environmental Matters.

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussion or implementation. In the United States, these efforts include legislative proposals and EPA regulations at the federal level, actions at the state level, and private party litigation related to greenhouse gas emissions. While the U.S. Congress has from time to time considered legislation aimed at reducing emissions of greenhouse gases, Congress has not yet passed any federal climate change legislation and we cannot predict when or if Congress will pass such legislation and in what form. In the absence of such legislation, the EPA is regulating greenhouse gas emissions pursuant to the authority granted to it by the federal Clean Air Act. For example, in April 2012, the EPA adopted rules which restrict emissions associated with oil and natural gas drilling. Compliance with these new rules will not materially change the Company s ongoing emissions limiting technologies and practices, and is not expected to have a significant impact on the Company. In addition, the U.S. Congress has from time to time considered bills that would establish a cap-and-trade program to reduce emissions of greenhouse gases. Legislation or regulation that restricts carbon emissions could increase the Company s cost of environmental compliance by requiring the Company to install new equipment to reduce emissions from larger facilities and/or purchase emission allowances. International, federal, state or regional climate change and greenhouse gas measures could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard to existing and new facilities, or impose additional monitoring and reporting requirements. Climate change and greenhouse gas initiatives, and incentives to conserve energy or use alternative energy sources, could also reduce demand for oil and natural gas. But legislation or regulation that sets a price on or otherwise restricts carbon emissions could also benefit the Company by increasing demand for natural gas, because substantially fewer carbon emissions per Btu of heat generated are associated with the use of natural gas than with certain alternate fuels such as coal and oil. The effect (material or not) on the Company of any new legislative or regulatory measures will depend on the particular provisions that are ultimately adopted.

NEW AUTHORITATIVE ACCOUNTING AND FINANCIAL REPORTING GUIDANCE

In December 2011, the FASB issued authoritative guidance requiring enhanced disclosures regarding offsetting assets and liabilities. Companies are required to disclose both gross information and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. This authoritative guidance will be effective as of the Company s first quarter of fiscal 2014 and is not expected to have a significant impact on the Company s financial statements.

In February 2013, the FASB issued authoritative guidance requiring enhanced disclosures regarding the reporting of amounts reclassified out of accumulated other comprehensive income. The authoritative guidance requires parenthetical disclosure on the face of the financial statements or a single footnote that

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would provide more detail about the components of reclassification adjustments that are reclassified in their entirety to net income. If a component of a reclassification adjustment is not reclassified in its entirety to net income, a cross reference would be made to the footnote disclosure that provides a more thorough discussion of the component involved in that reclassification adjustment. This authoritative guidance will be effective as of the Company s first quarter of fiscal 2014. The Company does not expect this guidance to have a material impact.

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-l defined in the Private Securities Litigation Reform Act of 1995 and accordingly involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. The Company s expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, but there can be no assurance that management s expectations, beliefs or projections will result or be achieved or accomplished. In addition to other factors and matters discussed elsewhere herein, the following are important factors that, in the view of the Company, could cause actual results to differ materially from those discussed in the forward-looking statements:

1. Factors affecting the Company s ability to successfully identify, drill for and produce economically viable natural gas and oil reserves, including among others geology, lease availability, title disputes, weather conditions, shortages, delays or unavailability of equipment and services required in drilling operations, insufficient gathering, processing and transportation capacity, the need to obtain governmental approvals and permits, and compliance with environmental laws and regulations;

2. 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;

3. Governmental/regulatory actions, initiatives and proceedings, including those involving rate cases (which address, among other things, allowed rates of return, rate design and retained natural gas), environmental/safety requirements, affiliate relationships, industry structure, and franchise renewal;

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

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

6. Uncertainty of oil and gas reserve estimates;

7. Significant differences between the Company s projected and actual production levels for natural gas or oil;

8. Changes in demographic patterns and weather conditions;

9. Changes in the availability, price or accounting treatment of derivative financial instruments;

10. 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;

11. 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;

12. 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;

13. The creditworthiness or performance of the Company s key suppliers, customers and counterparties;

14. Economic disruptions or uninsured losses resulting from major accidents, fires, severe weather, natural disasters, terrorist activities, acts of war, cyber attacks or pest infestation;

15. Changes in price differential between similar quantities of natural gas at different geographic locations, and the effect of such changes on natural gas revenues and production, and on the demand for pipeline transportation capacity to or from such locations;

16. Other changes in price differentials between similar quantities of oil or natural gas having different quality, heating value, geographic location or delivery date;

17. Significant differences between the Company s projected and actual capital expenditures and operating expenses;

18. 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;

19. The cost and effects of legal and administrative claims against the Company or activist shareholder campaigns to effect changes at the Company;

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

21. Increasing costs of insurance, changes in coverage and the ability to obtain insurance.

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

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

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

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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 M Supplementary Information for Oil and Gas Producing Activities (unaudited), appears under this Item, and reference is made thereto.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

In our opinion, the consolidated financial statements listed in the accompanying index present fairly, in all material respects, the financial position of National Fuel Gas Company and its subsidiaries at September 30, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2013 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of September 30, 2013, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company s management is responsible for these financial statements and financial statement schedule, 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 Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company s internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. 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.

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.

PricewaterhouseCoopers LLP

Buffalo, New York

November 22, 2013

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NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND EARNINGS

REINVESTED IN THE BUSINESS

	Year Ended September 30		
	2013	2012	2011
	(Thousands of dollars, except per common share amounts)		
INCOME			
Operating Revenues	$ 1,829,551	$ 1,626,853	$ 1,778,842
Operating Expenses			
Purchased Gas	460,432	415,589	628,732
Operation and Maintenance	442,090	401,397	400,519
Property, Franchise and Other Taxes	82,431	90,288	81,902
Depreciation, Depletion and Amortization	326,760	271,530	226,527
	1,311,713	1,178,804	1,337,680
Operating Income	517,838	448,049	441,162
Other Income (Expense):			
Gain on Sale of Unconsolidated Subsidiaries			50,879
Other Income	4,697	5,133	5,947
Interest Income	4,335	3,689	2,916
Interest Expense on Long-Term Debt	(90,273)	(82,002)	(73,567)
Other Interest Expense	(3,838)	(4,238)	(4,554)
Income Before Income Taxes	432,759	370,631	422,783
Income Tax Expense	172,758	150,554	164,381
Net Income Available for Common Stock	260,001	220,077	258,402
EARNINGS REINVESTED IN THE BUSINESS			
Balance at Beginning of Year	1,306,284	1,206,022	1,063,262
	1,566,285	1,426,099	1,321,664
Dividends on Common Stock	(123,668)	(119,815)	(115,642)
Balance at End of Year	$ 1,442,617	$ 1,306,284	$ 1,206,022
Earnings Per Common Share:			
Basic:			
Net Income Available for Common Stock	$ 3.11	$ 2.65	$ 3.13
Diluted:			
Net Income Available for Common Stock	$ 3.08	$ 2.63	$ 3.09
Weighted Average Common Shares Outstanding:			
Used in Basic Calculation	83,518,857	83,127,844	82,514,015
Used in Diluted Calculation	84,341,220	83,739,771	83,670,802

See Notes to Consolidated Financial Statements

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NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended September 30		
	2013	**2012**	**2011**
	(Thousands of dollars)		
Net Income Available for Common Stock	$ 260,001	$ 220,077	$ 258,402
Other Comprehensive Income (Loss), Before Tax:			
Increase (Decrease) in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	55,940	(27,552)	(24,172)
Reclassification Adjustment for Amortization of Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans	15,282	10,270	8,536
Foreign Currency Translation Adjustment			17
Reclassification Adjustment for Realized Foreign Currency Translation Loss in Net Income			34
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	5,041	3,545	(1,199)
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	91,790	(7,248)	30,238
Reclassification Adjustment for Realized Gains on Derivative Financial Instruments in Net Income	(36,029)	(65,691)	(15,485)
Other Comprehensive Income (Loss), Before Tax	132,024	(86,676)	(2,031)
Income Tax Expense (Benefit) Related to the Increase (Decrease) in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	21,304	(10,144)	(8,735)
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	5,650	3,836	3,221
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	1,847	1,311	(453)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	38,236	(8,244)	12,836
Reclassification Adjustment for Income Tax Expense on Realized Gains on Derivative Financial Instruments in Net Income	(14,799)	(22,114)	(6,186)
Income Taxes Net	52,238	(35,355)	683
Other Comprehensive Income (Loss)	79,786	(51,321)	(2,714)
Comprehensive Income	$ 339,787	$ 168,756	$ 255,688

See Notes to Consolidated Financial Statements

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NATIONAL FUEL GAS COMPANY

CONSOLIDATED BALANCE SHEETS

	At September 30 2013	2012
	(Thousands of dollars)	
ASSETS		
Property, Plant and Equipment	$ 7,313,203	$ 6,615,813
Less Accumulated Depreciation, Depletion and Amortization	2,161,477	1,876,010
	5,151,726	4,739,803
Current Assets		
Cash and Temporary Cash Investments	64,858	74,494
Hedging Collateral Deposits	1,094	364
Receivables Net of Allowance for Uncollectible Accounts of $27,144 and $30,317, Respectively	133,182	115,818
Unbilled Utility Revenue	19,483	19,652
Gas Stored Underground	51,484	49,795
Materials and Supplies at average cost	29,904	28,577
Unrecovered Purchased Gas Costs	12,408	
Other Current Assets	56,905	56,121
Deferred Income Taxes	79,359	10,755
	448,677	355,576
Other Assets		
Recoverable Future Taxes	163,355	150,941
Unamortized Debt Expense	16,645	13,409
Other Regulatory Assets	252,568	546,851
Deferred Charges	9,382	7,591
Other Investments	96,308	86,774
Goodwill	5,476	5,476
Prepaid Post-Retirement Benefit Costs	22,774	
Fair Value of Derivative Financial Instruments	48,989	27,616
Other	2,447	1,105
	617,944	839,763
Total Assets	$ 6,218,347	$ 5,935,142
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders Equity		
Common Stock, $1 Par Value		
Authorized 200,000,000 Shares; Issued and Outstanding 83,661,969 Shares and 83,330,140 Shares, Respectively	$ 83,662	$ 83,330
Paid In Capital	687,684	669,501
Earnings Reinvested in the Business	1,442,617	1,306,284
Accumulated Other Comprehensive Loss	(19,234)	(99,020)
Total Comprehensive Shareholders Equity	2,194,729	1,960,095
Long-Term Debt, Net of Current Portion	1,649,000	1,149,000
Total Capitalization	3,843,729	3,109,095
Current and Accrued Liabilities		

Notes Payable to Banks and Commercial Paper		171,000
Current Portion of Long-Term Debt		250,000
Accounts Payable	105,283	87,985
Amounts Payable to Customers	12,828	19,964
Dividends Payable	31,373	30,416
Interest Payable on Long-Term Debt	29,960	29,491
Customer Advances	21,959	24,055
Customer Security Deposits	16,183	17,942
Other Accruals and Current Liabilities	83,946	79,099
Fair Value of Derivative Financial Instruments	639	24,527
	302,171	734,479
Deferred Credits		
Deferred Income Taxes	1,347,007	1,065,757
Taxes Refundable to Customers	85,655	66,392
Unamortized Investment Tax Credit	1,579	2,005
Cost of Removal Regulatory Liability	157,622	139,611
Other Regulatory Liabilities	61,549	21,014
Pension and Other Post-Retirement Liabilities	158,014	516,197
Asset Retirement Obligations	119,511	119,246
Other Deferred Credits	141,510	161,346
	2,072,447	2,091,568
Commitments and Contingencies		
Total Capitalization and Liabilities	$ 6,218,347	$ 5,935,142

See Notes to Consolidated Financial Statements

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NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2013	2012	2011
	(Thousands of dollars)		
Operating Activities			
Net Income Available for Common Stock	$ 260,001	$ 220,077	$ 258,402
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Gain on Sale of Unconsolidated Subsidiaries			(50,879)
Depreciation, Depletion and Amortization	326,760	271,530	226,527
Deferred Income Taxes	167,887	144,150	164,251
Excess Tax Costs (Benefits) Associated with Stock-Based Compensation Awards	(675)	(985)	1,224
Elimination of Other Post-Retirement Regulatory Liability		(21,672)	
Stock-Based Compensation	12,446	7,939	7,683
Other	14,965	5,013	7,968
Change in:			
Hedging Collateral Deposits	(730)	19,337	(8,567)
Receivables and Unbilled Utility Revenue	(17,135)	13,859	3,887
Gas Stored Underground and Materials and Supplies	(3,016)	5,405	(9,934)
Unrecovered Purchased Gas Costs	(12,408)		
Other Current Assets	(109)	9,790	83,245
Accounts Payable	8,303	(16,773)	13,698
Amounts Payable to Customers	(7,136)	4,445	(22,590)
Customer Advances	(2,096)	4,412	(7,995)
Customer Security Deposits	(1,759)	621	(999)
Other Accruals and Current Liabilities	666	10,633	242
Other Assets	(5,757)	(4,396)	18,042
Other Liabilities	(1,635)	(14,375)	(30,253)
Net Cash Provided by Operating Activities	738,572	659,010	653,952
Investing Activities			
Capital Expenditures	(703,461)	(1,035,007)	(814,278)
Net Proceeds from Sale of Unconsolidated Subsidiaries			59,365
Net Proceeds from Sale of Oil and Gas Producing Properties			63,501
Other	(2,522)	446	(2,908)
Net Cash Used in Investing Activities	(705,983)	(1,034,561)	(694,320)
Financing Activities			
Change in Notes Payable to Banks and Commercial Paper	(171,000)	131,000	40,000
Excess Tax (Costs) Benefits Associated with Stock-Based Compensation Awards	675	985	(1,224)
Net Proceeds from Issuance of Long-Term Debt	495,415	496,085	
Reduction of Long-Term Debt	(250,000)	(150,000)	(200,000)
Net Proceeds from Issuance (Repurchase) of Common Stock	5,395	10,345	(592)
Dividends Paid on Common Stock	(122,710)	(118,798)	(114,559)
Net Cash Provided By (Used in) Financing Activities	(42,225)	369,617	(276,375)
Net Decrease in Cash and Temporary Cash Investments	(9,636)	(5,934)	(316,743)
Cash and Temporary Cash Investments At Beginning of Year	74,494	80,428	397,171

Cash and Temporary Cash Investments At End of Year	$ 64,858	$ 74,494	$ 80,428
Supplemental Disclosure of Cash Flow Information			
Cash Paid For:			
Interest	$ 91,215	$ 79,820	$ 80,929
Income Taxes (Refunded)	$ 13,187	$ 474	$ (63,105)

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.

During the quarter ended March 31, 2011, the Company sold its 50% equity method investments in Seneca Energy and Model City for $59.4 million, resulting in a gain of $50.9 million. Seneca Energy and Model City generate and sell electricity using methane gas obtained from landfills owned by outside parties.

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.

Reclassifications and Revisions

Certain prior year amounts have been reclassified to conform with current year presentation.

Revisions were made on the Consolidated Statement of Cash Flows for the years ended September 30, 2012 and September 30, 2011 to reflect non-cash investing activities embedded in Accounts Payable on the Consolidated Balance Sheets at September 30, 2012, September 30, 2011 and September 30, 2010. These revisions reduced the operating cash flows related to the change in Accounts Payable for the years ended September 30, 2012 and September 30, 2011 by $1.8 million and $6.6 million, respectively, and increased investing cash flows related to Capital Expenditures by the same amounts. The revisions in the Consolidated Statements of Cash Flows noted above represent errors that are not deemed material, individually or in the aggregate, to the prior period consolidated financial statements.

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 Utility segment records revenue as bills are rendered, except that service supplied but not billed is reported as unbilled utility revenue and is included in operating revenues for the year in which service is furnished.

The Company s Energy Marketing segment records revenue as bills are rendered for service supplied on a monthly basis.

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

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 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.

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,

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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.

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

Capitalized costs include costs related to unproved properties, which are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. 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 April 2011, the Company completed the sale of its off-shore oil and natural gas properties in the Gulf of Mexico. The Company received net proceeds of $55.4 million from this sale. The Company also eliminated the asset retirement obligation associated with its off-shore oil and gas properties. This obligation amounted to $37.5 million and was accounted for as a reduction of capitalized costs under the full cost method of accounting for oil and natural gas properties as well as a reduction of the asset retirement obligation. Asset retirement obligations are discussed further in Note B Asset Retirement Obligations.

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. In adjusting estimated future net cash flows for hedging under the ceiling test at September 30, 2013, 2012, and 2011, estimated future net cash flows were increased by $71.6 million, $128.4 million and $35.4 million, respectively. At September 30, 2013, the ceiling exceeded the book value of the oil and gas properties by approximately $159.4 million.

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.

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, depletion 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	
	2013	2012
	(Thousands)	
Utility	$ 1,778,140	$ 1,737,645
Pipeline and Storage	1,547,192	1,406,433
Exploration and Production	3,437,767	2,828,358
Energy Marketing	3,460	2,865
Gathering	130,082	86,019
All Other and Corporate	109,690	110,574
	$ 7,006,331	$ 6,171,894

Average depreciation, depletion and amortization rates are as follows:

	Year Ended September 30		
	2013	2012	2011
Utility	2.6%	2.6%	2.6%
Pipeline and Storage	2.5%	2.9%	3.1%
Exploration and Production, per Mcfe(1)	$ 2.02	$ 2.25	$ 2.17
Energy Marketing	3.9%	3.6%	2.5%
Gathering	3.7%	3.3%	4.3%
All Other and Corporate	1.3%	1.1%	0.8%

(1) Amounts include depletion of oil and gas producing properties as well as depreciation of fixed assets. As disclosed in Note M Supplementary Information for Oil and Gas Producing Properties, depletion of oil and gas producing properties amounted to $1.98, $2.19 and $2.12 per Mcfe of production in 2013, 2012 and 2011, respectively.

Goodwill

The Company has recognized goodwill of $5.5 million as of September 30, 2013 and 2012 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, 2013, 2012 and 2011, 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.

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Financial Instruments

Unrealized gains or losses from the Company s investments in an equity 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. 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 or purchased gas expense on the Consolidated Statements of Income. Any ineffectiveness associated with the cash flow hedges is recorded in the Consolidated Statements of Income. The Company recorded a $2.0 million loss in Operating Revenues on the Consolidated Statement of Income related to mark-to-market adjustments associated with its cash flow hedges during 2013. The Company did not experience any material ineffectiveness with regard to its cash flow hedges during 2012 or 2011. In addition, the Company has certain derivative instruments that while considered economic hedges do not qualify as either cash flow or fair value hedges. The Company recorded $1.7 million of mark-to-market losses in Operating Revenues on the Consolidated Statement of Income associated with these derivative instruments in fiscal 2013.

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. The Company did not experience any material ineffectiveness with regard to its fair value hedges during 2013, 2012 or 2011.

Accumulated Other Comprehensive Income (Loss)

The components of Accumulated Other Comprehensive Income (Loss) are as follows:

	Year Ended September 30	
	2013	2012
	(Thousands)	
Funded Status of the Pension and Other Post-Retirement Benefit Plans	$ (56,293)	$ (100,561)
Net Unrealized Gain (Loss) on Derivative Financial Instruments	30,722	(1,602)
Net Unrealized Gain on Securities Available for Sale	6,337	3,143
Accumulated Other Comprehensive Loss	$ (19,234)	$ (99,020)

At September 30, 2013, it is estimated that $15.2 million of unrealized gains on derivative financial instruments will be reclassified into the Consolidated Statement of Income during 2014 with $15.5 million of

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

unrealized gains on derivative financial instruments being reclassified into the Consolidated Statement of Income in subsequent years. These instruments, which are classified as cash flow hedges, extend out to 2018.

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 credit was $0.3 million and $0.4 million at September 30, 2013 and 2012, respectively. The total amount for accumulated losses was $56.6 million and $100.9 million at September 30, 2013 and 2012, respectively.

Gas Stored Underground Current

In the Utility segment, gas stored underground current in the amount of $30.7 million is carried at lower of cost or market, on a LIFO method. Based upon the average price of spot market gas purchased in September 2013, including transportation costs, the current cost of replacing this inventory of gas stored underground current exceeded the amount stated on a LIFO basis by approximately $59.1 million at September 30, 2013. All other gas stored underground current, which is in the Energy Marketing segment, is carried at an average cost method, subject to lower of cost or market adjustments.

Unamortized Debt Expense

Costs associated with the issuance of debt by the Company are deferred and amortized over the lives of the related debt.

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, 2013, the remaining weighted average amortization period for such costs was approximately 6 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. Investment tax credit, prior to its repeal in 1986, was deferred and is being amortized over the estimated useful lives of the related property, as required by regulatory authorities having jurisdiction.

Consolidated Statements of Cash Flows

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

The Company has accounts payable and accrued liabilities recorded on its Consolidated Balance Sheets that are related to capital expenditures. These amounts represent non-cash investing activities at the balance sheet date. Accordingly, they are excluded from the Consolidated Statement of Cash Flows when they are recorded as liabilities and included in the Consolidated Statement of Cash Flows when they are paid in the subsequent period. The following table summarizes the Company s non-cash capital expenditures recorded as Accounts Payable and Other Accruals and Current Liabilities on the Consolidated Balance Sheet:

	At September 30			
	2013	**2012**	**2011**	**2010**
	(Thousands)			
Non-cash Capital Expenditures	$ 81,138	$ 67,503	$ 125,115	$ 85,206

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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. At September 30, 2013, the Company had hedging collateral deposits of $1.1 million related to its exchange-traded futures contracts. At September 30, 2012, the Company had hedging collateral deposits of $0.4 million related to its exchange-traded futures contracts. 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	
	2013	2012
	(Thousands)	
Prepayments	$ 10,605	$ 8,316
Prepaid Property and Other Taxes	13,079	14,455
Federal Income Taxes Receivable	1,122	268
State Income Taxes Receivable	3,275	2,065
Fair Values of Firm Commitments	1,829	1,291
Regulatory Assets	26,995	29,726
	$ 56,905	$ 56,121

Other Accruals and Current Liabilities

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

	Year Ended September 30	
	2013	2012
	(Thousands)	
Accrued Capital Expenditures	$ 41,100	$ 36,460
Regulatory Liabilities	20,013	18,289
Other	22,833	24,350
	$ 83,946	$ 79,099

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, 2013 and 2012, customers in the balanced billing programs had advanced excess funds of $22.0 million and $24.1 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, 2013 and 2012, the Company had received customer security deposits amounting to $16.2 million and $17.9 million, respectively.

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Earnings Per Common Share

Basic earnings per common share is computed by dividing income available for common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. For purposes of determining earnings per common share, the only potentially dilutive securities the Company has outstanding are stock options, SARs and restricted stock units. 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 and restricted stock units that are antidilutive are excluded from the calculation of diluted earnings per common share. For 2013 and 2012, 181,418 securities and 844,872 securities were excluded as being antidilutive, respectively. For 2011, there were no securities excluded as being antidilutive.

Stock-Based Compensation

The Company has various stock option and stock award plans which provide or provided for the issuance of one or more of the following to key employees: incentive stock options, nonqualified stock options, SARs, restricted stock, restricted stock units, performance units or performance shares. Stock options and SARs under all plans have exercise prices equal to the average market price of Company common stock on the date of grant, and generally no stock option or SAR is exercisable less than one year or more than ten years after the date of each grant. 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 option and 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.

The Company follows authoritative guidance which requires the measurement and recognition of compensation cost at fair value for all share-based payments, including stock options and SARs. The Company has chosen the Black-Scholes-Merton closed form model to calculate the compensation expense associated with such share-based payments since it does not have complex stock-based compensation awards.

Stock-based compensation expense for the years ended September 30, 2013, 2012 and 2011 was approximately $11.5 million, $7.2 million, and $6.7 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, 2013, 2012 and 2011 was approximately $4.6 million, $2.9 million and $2.7 million, respectively. A portion of stock-based compensation expense is subject to capitalization under IRS uniform capitalization rules. Less than $0.1 million was capitalized under these rules during the year ended September 30, 2013 and nothing was capitalized during the years ended September 30, 2012 and 2011.

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company realized excess tax benefits related to stock-based compensation of $4.4 million, $14.2 million, and $19.0 million for the fiscal years ended September 30, 2013, 2012 and 2011, respectively. The Company only recorded tax benefits of $0.7 million, $0.6 million, and $0.4 million related to the fiscal years ended September 30, 2013, 2012 and 2011, respectively, due to tax loss carryforwards.

For a summary of transactions during 2013 involving option shares, SARs, restricted share awards, non-performance based restricted stock units and performance based restricted stock units for all plans, refer to Note E Capitalization and Short-Term Borrowings.

Stock Options

The total intrinsic value of stock options exercised during the years ended September 30, 2013, 2012 and 2011 totaled approximately $11.6 million, $13.5 million, and $44.6 million, respectively. For 2013, 2012 and 2011, the amount of cash received by the Company from the exercise of such stock options was approximately $2.6 million, $7.6 million, and $9.5 million, respectively.

There were not any stock options granted during the years ended September 30, 2013, 2012 and 2011. For the years ended September 30, 2013, 2012 and 2011, there were not any stock options that became fully vested. There was not any unrecognized compensation expense related to stock options at September 30, 2013.

SARs

The Company granted 412,970, 166,000 and 195,000 SARs during the years ended September 30, 2013, 2012 and 2011, respectively. The SARs granted in 2013 and 2011 may be settled in cash, in shares of common stock of the Company, or in a combination of cash and shares of common stock of the Company, as determined by the Company. The SARs granted in 2012 will be settled in shares of common stock of the Company. 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 SARs granted during the years ended September 30, 2013 and September 30, 2011 vest and become exercisable annually in one-third increments. The SARs granted during the year ended September 30, 2012 vest annually in one-third increments and become exercisable on the third anniversary of the date of grant. The weighted average grant date fair value of the SARs granted during the years ended September 30, 2013, 2012 and 2011 was estimated on the date of grant using the same accounting treatment that is applied for stock options.

The weighted average grant date fair value of SARs granted in 2013, 2012 and 2011 was $10.66, $11.20 and $15.01, respectively. The total intrinsic value of SARs exercised during the years ended September 30, 2013, 2012 and 2011 totaled approximately $0.8 million, less than $0.1 million, and approximately $0.3 million, respectively. For the years ended September 30, 2013, 2012 and 2011, 287,168, 435,169 and 376,819 SARs became fully vested. The total fair value of the SARs that became vested during each of the years ended September 30, 2013, 2012 and 2011 was approximately $3.6 million, $3.8 million and $2.9 million, respectively. As of September 30, 2013, unrecognized compensation expense related to SARs totaled approximately $1.5 million, which will be recognized over a weighted average period of 10.6 months.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The fair value of SARs at the date of grant was estimated using the Black-Scholes-Merton closed form model. The following weighted average assumptions were used in estimating the fair value of SARs at the date of grant:

	Year Ended September 30		
	2013	2012	2011
Risk-Free Interest Rate	1.55%	1.59%	2.94%
Expected Life (Years)	8.25	8.25	8.00
Expected Volatility	25.61%	24.97%	23.38%
Expected Dividend Yield (Quarterly)	0.69%	0.64%	0.55%

The risk-free interest rate is based on the yield of a Treasury Note with a remaining term commensurate with the expected term of the SARs. The expected life and expected volatility are based on historical experience.

For grants during the years ended September 30, 2013, 2012 and 2011, it was assumed that there would be no forfeitures, based on the vesting term and the number of grantees.

Restricted Share Awards

The Company did not grant any restricted share awards (non-vested stock as defined by the current accounting literature) during the year ended September 30, 2013. The Company granted 41,525 and 47,250 restricted share awards during the years ended September 30, 2012 and 2011, respectively. The weighted average fair value of restricted share awards granted in 2012 and 2011 is $55.09 per share and $63.98 per share, respectively. As of September 30, 2013, unrecognized compensation expense related to restricted share awards totaled approximately $2.2 million, which will be recognized over a weighted average period of 2.6 years.

Restricted Stock Units

The Company granted 44,200, 68,450 and 41,800 non-performance based restricted stock units during the years ended September 30, 2013, 2012 and 2011, respectively. The weighted average fair value of such non-performance based restricted stock units granted in 2013, 2012 and 2011 was $51.11 per share, $47.10 per share and $59.35 per share, respectively. As of September 30, 2013, unrecognized compensation expense related to non-performance based restricted stock units totaled approximately $4.1 million, which will be recognized over a weighted average period of 1.9 years.

The Company granted 255,604 performance based restricted stock units during the year ended September 30, 2013. The Company did not grant any performance based restricted stock units during the years ended September 30, 2012 and 2011. The weighted average fair value of such performance based restricted stock units granted in 2013 was $49.51 per share. The performance based restricted stock units granted during the year ended September 30, 2013 must meet a performance condition over the performance cycle of October 1, 2012 to September 30, 2015. The performance condition over the performance cycle, generally stated, is the Company s total return on capital as compared to the same metric for companies in the Natural Gas Distribution and Integrated Natural Gas Companies group as calculated and reported in the Monthly Utility Reports of AUS, Inc., a leading industry consultant. The number of performance based restricted stock units that will vest will depend upon the Company s performance relative to the report group and not upon the absolute level of return achieved by the Company. As of September 30, 2013, unrecognized compensation expense related to performance based restricted stock units totaled approximately $7.9 million, which will be recognized over a weighted average period of 1.5 years.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

New Authoritative Accounting and Financial Reporting Guidance

In December 2011, the FASB issued authoritative guidance requiring enhanced disclosures regarding offsetting assets and liabilities. Companies are required to disclose both gross information and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. This authoritative guidance will be effective as of the Company s first quarter of fiscal 2014 and is not expected to have a significant impact on the Company s financial statements.

In February 2013, the FASB issued authoritative guidance requiring enhanced disclosures regarding the reporting of amounts reclassified out of accumulated other comprehensive income. The authoritative guidance requires parenthetical disclosure on the face of the financial statements or a single footnote that would provide more detail about the components of reclassification adjustments that are reclassified in their entirety to net income. If a component of a reclassification adjustment is not reclassified in its entirety to net income, a cross reference would be made to the footnote disclosure that provides a more thorough discussion of the component involved in that reclassification adjustment. This authoritative guidance will be effective as of the Company s first quarter of fiscal 2014. The Company does not expect this guidance to have a material impact.

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). 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.

The full cost method of accounting provides a limit to the amount of costs that can be capitalized in the full cost pool. This limit is referred to as the full cost ceiling. 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.

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

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 and services components of the pipeline system in the Utility segment and with the transmission mains and other components in the pipeline system in the Pipeline and Storage segment. These retirement costs within the distribution and transmission 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.

A reconciliation of the Company s asset retirement obligations are shown below:

	Year Ended September 30		
	2013	2012	2011
		(Thousands)	
Balance at Beginning of Year	$ 119,246	$ 75,731	$ 101,618
Liabilities Incurred and Revisions of Estimates	(4,796)	41,653	10,346
Liabilities Settled	(1,744)	(2,997)	(41,704)
Accretion Expense	6,805	4,859	5,471
Balance at End of Year	$ 119,511	$ 119,246	$ 75,731

Note C Regulatory Matters

Regulatory Assets and Liabilities

The Company has recorded the following regulatory assets and liabilities:

	At September 30	
	2013	2012
	(Thousands)	
Regulatory Assets(1):		
Pension Costs(2) (Note H)	$ 187,181	$ 344,228
Post-Retirement Benefit Costs(2) (Note H)	29,838	154,415
Recoverable Future Taxes (Note D)	163,355	150,941
Environmental Site Remediation Costs(2) (Note I)	18,104	17,843
NYPSC Assessment(3)	13,169	17,420
Asset Retirement Obligations(2) (Note B)	11,837	26,942
Unamortized Debt Expense (Note A)	3,276	3,997
Other(4)	19,434	15,729
Total Regulatory Assets	446,194	731,515
Less: Amounts Included in Other Current Assets	(26,995)	(29,726)
Total Long-Term Regulatory Assets	$ 419,199	$ 701,789

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	At September 30 2013	2012
	(Thousands)	
Regulatory Liabilities:		
Cost of Removal Regulatory Liability	$ 157,622	$ 139,611
Taxes Refundable to Customers (Note D)	85,655	66,392
Post-Retirement Benefit Costs (Note H)	37,923	3,885
Amounts Payable to Customers (See Regulatory Mechanisms in Note A)	12,828	19,964
Off-System Sales and Capacity Release Credits(5)	10,228	16,262
Other(6)	33,411	19,156
Total Regulatory Liabilities	337,667	265,270
Less: Amounts included in Current and Accrued Liabilities	(32,841)	(38,253)
Total Long-Term Regulatory Liabilities	$ 304,826	$ 227,017

(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) Amounts are included in Other Current Assets on the Consolidated Balance Sheets at September 30, 2013 and September 30, 2012 since such amounts are expected to be recovered from ratepayers in the next 12 months.

(4) $13,826 and $12,306 are included in Other Current Assets on the Consolidated Balance Sheets at September 30, 2013 and 2012, respectively, since such amounts are expected to be recovered from ratepayers in the next 12 months. $5,608 and $3,423 are included in Other Regulatory Assets on the Consolidated Balance Sheets at September 30, 2013 and 2012, respectively.

(5) Amounts are included in Other Accruals and Current Liabilities on the Consolidated Balance Sheets at September 30, 2013 and September 30, 2012 since such amounts are expected to be passed back to ratepayers in the next 12 months.

(6) $9,785 and $2,027 are included in Other Accruals and Current Liabilities on the Consolidated Balance Sheets at September 30, 2013 and 2012, respectively, since such amounts are expected to be recovered from ratepayers in the next 12 months. $23,626 and $17,129 are included in Other Regulatory Liabilities on the Consolidated Balance Sheets at September 30, 2013 and 2012, 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

NYPSC Assessment

On April 7, 2009, the Governor of the State of New York signed into law an amendment to the Public Service Law increasing the allowed utility assessment from the then current rate of one-third of one percent to one percent of a utility s in-state gross operating revenue, together with a temporary surcharge (expiring March 31, 2014) equal, as applied, to an additional one percent of the utility s in-state gross operating revenue. The NYPSC, in a generic proceeding initiated for the purpose of implementing the amended law, has authorized the recovery, through rates, of the full cost of the increased assessment. The assessment is currently being applied to customer bills in the Utility segment s New York jurisdiction.

NYPSC Rate Proceeding

Following discussions with regulatory staff with respect to earnings levels, on March 27, 2013, Distribution Corporation filed a plan (Plan) with the NYPSC proposing to adopt an earnings stabilization and sharing mechanism that would allocate earnings above a rate of return on equity of 9.96% evenly between shareholders and an accounting reserve (Reserve). The Reserve would be utilized to stabilize Distribution Corporation s earnings and to fund customer benefit programs. The Plan also proposed to increase capital spending and to aid new customer system expansion efforts. Discussions were held with NYPSC staff and others with respect to the Plan.

In a related development, on April 19, 2013, the NYPSC issued an order directing Distribution Corporation to either agree to make its rates and charges temporary subject to refund effective June 1, 2013, or show cause why its gas rates and charges should not be set on a temporary basis subject to refund (Order). The Order recognized Distribution Corporation s Plan and, while acknowledging the Company s cost-cutting and efficiency achievements, determined nonetheless that the Plan did not propose to adjust existing rates . . . enough to compensate for the imbalance between ratepayer and shareholder interests that has developed since . . . 2007 . . . Pursuant to the Order, the NYPSC commenced a temporary rate proceeding and, following hearings, on June 14, 2013, the NYPSC issued an order (Temporary Rates Order) making Distribution Corporation s rates and charges temporary and subject to refund pending the determination of permanent gas rates through further rate proceedings. Discussions for settlement of Distribution Corporation s rates and charges were commenced and are expected to continue as the formal case to establish permanent rates proceeds along a parallel path. The Consolidated Balance Sheet at September 30, 2013 reflects a $7.5 million refund provision in anticipation of a potential settlement.

In addition to authorizing a temporary rate proceeding, the Order also suggested an examination of the applicability of a provision of New York public utility law, PSL §66(20), that provides the NYPSC with stated authority to direct a refund of revenues received by a utility in excess of its authorized rate of return for a period of twelve months. On May 17, 2013, Distribution Corporation commenced an action in New York Supreme Court, Erie County, seeking the court s declaration that PSL §66(20) is unconstitutional. On October 25, 2013, the court dismissed Distribution Corporation s complaint without prejudice to recommence the action after a decision is rendered in the rate proceeding before the NYPSC. In addition, on September 25, 2013, Distribution Corporation commenced an appeal in New York Supreme Court, Albany County, seeking to annul the Temporary Rates Order on various grounds. Distribution Corporation is unable to predict the outcome of the administrative or judicial proceedings at this time.

Off-System Sales and Capacity Release Credits

The Company, in its Utility segment, has entered into off-system sales and capacity release transactions. Most of the margins on such transactions are returned to the customer with only a small percentage being retained by the Company. The amount owed to the customer has been deferred as a regulatory liability.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Supply Corporation Rate Proceeding

On August 6, 2012, the FERC issued an order approving a black box Stipulation and Agreement that resolved the issues arising from the general rate filing that Supply Corporation filed on October 31, 2011. The Stipulation and Agreement provides for, among other things, (i) an increase in Supply Corporation s base tariff rates effective May 1, 2012, (ii) implementation of a tracking mechanism to adjust fuel retention rates annually to reflect actual experience, replacing the previously fixed fuel retention rates, and (iii) the elimination of a past net regulatory liability associated with post-retirement benefits. Supply Corporation is not required to amortize the liability or otherwise pass it back to customers under the Stipulation and Agreement. Accordingly, the elimination of the past net regulatory liability, totaling $21.7 million, has been recorded as an increase to operating revenues for the quarter ended September 30, 2012.

Note D Income Taxes

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

	Year Ended September 30		
	2013	2012 (Thousands)	2011
Current Income Taxes			
Federal	$ (632)	$ (8)	$ (1,390)
State	5,503	6,412	1,520
Deferred Income Taxes			
Federal	130,318	111,176	130,434
State	37,569	32,974	33,817
	172,758	150,554	164,381
Deferred Investment Tax Credit	(426)	(581)	(697)
Total Income Taxes	$ 172,332	$ 149,973	$ 163,684
Presented as Follows:			
Other Income	$ (426)	$ (581)	$ (697)
Income Tax Expense	172,758	150,554	164,381
Total Income Taxes	$ 172,332	$ 149,973	$ 163,684

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

	Year Ended September 30		
	2013	2012 (Thousands)	2011
U.S. Income Before Income Taxes	$ 432,333	$ 370,050	$ 422,086
Income Tax Expense, Computed at U.S. Federal Statutory Rate of 35%	$ 151,317	$ 129,518	$ 147,730
Increase (Reduction) in Taxes Resulting from:			

State Income Taxes	27,997	25,601	22,969
Miscellaneous	(6,982)	(5,146)	(7,015)
Total Income Taxes	$ 172,332	$ 149,973	$ 163,684

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	At September 30 2013	2012
	(Thousands)	
Deferred Tax Liabilities:		
Property, Plant and Equipment	$ 1,504,187	$ 1,333,574
Pension and Other Post-Retirement Benefit Costs	124,021	236,431
Other	75,419	43,294
Total Deferred Tax Liabilities	1,703,627	1,613,299
Deferred Tax Assets:		
Pension and Other Post-Retirement Benefit Costs	(130,256)	(276,501)
Tax Loss Carryforwards	(215,262)	(198,744)
Other	(90,461)	(83,052)
Total Deferred Tax Assets	(435,979)	(558,297)
Total Net Deferred Income Taxes	$ 1,267,648	$ 1,055,002
Presented as Follows:		
Deferred Tax Liability/(Asset) Current	$ (79,359)	$ (10,755)
Deferred Tax Liability Non-Current	1,347,007	1,065,757
Total Net Deferred Income Taxes	$ 1,267,648	$ 1,055,002

As a result of certain realization requirements of the authoritative guidance on stock-based compensation, the table of deferred tax liabilities and assets shown above does not include certain deferred tax assets that arose directly from excess tax deductions related to stock-based compensation. Tax benefits of $0.7 million and $0.6 million relating to the excess stock-based compensation deductions were recorded in Paid in Capital during the years ended September 30, 2013 and September 30, 2012, respectively. Cumulative tax benefits of $36.4 million and $32.7 million remain as of September 30, 2013 and September 30, 2012, respectively, and will be recorded in Paid in Capital in future years when such tax benefits are realized.

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 $85.7 million and $66.4 million at September 30, 2013 and 2012, respectively. Also, regulatory assets representing future amounts collectible from customers, corresponding to additional deferred income taxes not previously recorded because of prior ratemaking practices, amounted to $163.4 million and $150.9 million at September 30, 2013 and 2012, respectively. Included in the above are regulatory liabilities and assets relating to the tax accounting method change noted below. The amounts are as follows: regulatory liabilities of $52.6 million and $47.3 million as of September 30, 2013 and 2012, respectively, and regulatory assets of $82.5 million and $65.9 million as of September 30, 2013 and 2012, respectively.

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

	Year Ended September 30		
	2013	2012	2011
		(Thousands)	
Balance at Beginning of Year	$ 11,170	$ 7,766	$ 8,490
Additions for Tax Positions Related to Current Year	700	1,600	80
Additions for Tax Positions of Prior Years	164	2,751	107
Reductions for Tax Positions of Prior Years	(10,033)	(947)	(911)
Balance at End of Year	$ 2,001	$ 11,170	$ 7,766

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As a result of certain examinations in process (discussed below), the Company anticipates the balance of unrecognized tax benefits could be reduced during the next 12 months. As of September 30, 2013, the entire balance of unrecognized tax benefits would favorably impact the effective tax rate, if recognized.

The Company recognizes interest relating to income taxes in Other Interest Expense and penalties relating to income taxes in Other Income. The Company did not recognize any interest expense relating to income taxes for fiscal 2013. The Company recognized interest expense relating to income taxes of $0.3 million during both fiscal 2012 and 2011. The Company has not accrued any penalties during fiscal 2013, 2012 and 2011.

The IRS is currently conducting examinations of the Company for fiscal 2012 and fiscal 2013 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. While the federal statute of limitations remains open for fiscal 2009 and later years, IRS examinations for fiscal 2008 and prior years have been completed and the Company believes such years are effectively settled. During fiscal 2009, 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. During the quarter ended March 31, 2013, local IRS examiners issued no-change reports for fiscal 2009, fiscal 2010 and fiscal 2011, but have reserved the right to re-examine these years, pending the anticipated issuance of IRS guidance addressing the accounting for certain capitalized costs for natural gas utilities. In addition, the Company negotiated a settlement of the fiscal 2011 Research Tax Credit.

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, 2013, the Company has a federal net operating loss (NOL) carryover of $570 million, which expires in varying amounts between 2023 and 2032. Approximately $23 million of this NOL is subject to certain annual limitations, and $93 million is attributable to excess tax deductions related to stock-based compensation as discussed above. In addition, the Company has state NOL carryovers in Pennsylvania, California and New York of $319 million, $177 million and $128 million, respectively, which begin to expire in varying amounts between 2029 and 2032. No valuation allowance was recorded on the federal or state NOL carryovers because of management s determination that the amounts will be fully utilized during the carryforward period.

On January 2, 2013, President Obama signed into law the American Taxpayer Relief Act of 2012 (the Relief Act). The Relief Act does not have a material effect on the Company s financial statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Note E Capitalization and Short-Term Borrowings

Summary of Changes in Common Stock Equity

	Common Stock		Paid In	Earnings Reinvested in the	Accumulated Other Comprehensive Income
	Shares	Amount	Capital	Business	(Loss)
	(Thousands, except per share amounts)				
Balance at September 30, 2010	82,075	$ 82,075	$ 645,619	$ 1,063,262	$ (44,985)
Net Income Available for Common Stock				258,402	
Dividends Declared on Common Stock ($1.40 Per Share)				(115,642)	
Other Comprehensive Loss, Net of Tax					(2,714)
Share-Based Payment Expense(2)			6,656		
Common Stock Issued (Repurchased) Under Stock and Benefit Plans(1)	738	738	(1,526)		
Balance at September 30, 2011	82,813	82,813	650,749	1,206,022	(47,699)
Net Income Available for Common Stock				220,077	
Dividends Declared on Common Stock ($1.44 Per Share)				(119,815)	
Other Comprehensive Loss, Net of Tax					(51,321)
Share-Based Payment Expense(2)			7,156		
Common Stock Issued Under Stock and Benefit Plans(1)	517	517	11,596		
Balance at September 30, 2012	83,330	83,330	669,501	1,306,284	(99,020)
Net Income Available for Common Stock				260,001	
Dividends Declared on Common Stock ($1.48 Per Share)				(123,668)	
Other Comprehensive Income, Net of Tax					79,786
Share-Based Payment Expense(2)			11,537		
Common Stock Issued Under Stock and Benefit Plans(1)	332	332	6,646		
Balance at September 30, 2013	83,662	$ 83,662	$ 687,684	$ 1,442,617(3)	$ (19,234)

(1) Paid in Capital includes tax benefits of $0.7 million for September 30, 2013, tax benefits of $1.0 million for September 30, 2012 and tax costs of $1.2 million for September 30, 2011 associated with the exercise of stock options and/or SARs.

(2) Paid in Capital includes compensation costs associated with stock option, SARs 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, 2013, $1.3 billion 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

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 2013, the Company issued 126,378 original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan.

During 2013, the Company issued 503,988 original issue shares of common stock as a result of stock option and SARs exercises. Holders of stock options, SARs or restricted stock will often tender shares of common stock to the Company for payment of option exercise prices and/or applicable withholding taxes. During 2013, 314,767 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 16,230 original issue shares of common stock during 2013.

Shareholder Rights Plan

In 1996, the Company s Board of Directors adopted a shareholder rights plan (Plan). The Plan has been amended several times since it was adopted and is now embodied in an Amended and Restated Rights Agreement effective December 4, 2008, a copy of which was included as an exhibit to the Form 8-K filed by the Company on December 4, 2008.

Pursuant to the Plan, the holders of the Company s common stock have one right (Right) for each of their shares. Each Right is initially evidenced by the Company s common stock certificates representing the outstanding shares of common stock.

The Rights have anti-takeover effects because they will cause substantial dilution of the Company s common stock if a person (an Acquiring Person) attempts to acquire the Company on terms not approved by the Board of Directors.

The Rights become exercisable upon the occurrence of a Distribution Date as described below, but after a Distribution Date Rights that are owned by an Acquiring Person will be null and void. At any time following a Distribution Date, each holder of a Right may exercise its right to receive, upon payment of an amount calculated under the Rights Agreement, common stock of the Company (or, under certain circumstances, other securities or assets of the Company) having a value equal to two times the amount paid to exercise the Right. However, the Rights are subject to redemption or exchange by the Company prior to their exercise as described below.

A Distribution Date would occur upon the earlier of (i) ten days after the public announcement that a person or group has acquired, or obtained the right to acquire, beneficial ownership of the Company s common stock or other voting stock (including Synthetic Long Positions as defined in the Plan) having 10% or more of the total voting power of the Company s common stock and other voting stock and (ii) ten days after the commencement or announcement by a person or group of an intention to make a tender or exchange offer that would result in that person acquiring, or obtaining the right to acquire, beneficial

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NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

ownership of the Company s common stock or other voting stock having 10% or more of the total voting power of the Company s common stock and other voting stock.

In certain situations after a person or group has acquired beneficial ownership of 10% or more of the total voting power of the Company s stock as described above, each holder of a Right will have the right to exercise its Rights to receive, upon exercise of the right, common stock of the acquiring company having a value equal to two times the amount paid to exercise the right. These situations would arise if the Company is acquired in a merger or other business combination or if 50% or more of the Company s assets or earning power are sold or transferred.

At any time prior to the end of the business day on the tenth day following the Distribution Date, the Company may redeem the Rights in whole, but not in part, at a price of $0.005 per Right, payable in cash or stock. A decision to redeem the Rights requires the vote of 75% of the Company s full Board of Directors. Also, at any time following the Distribution Date, 75% of the Company s full Board of Directors may vote to exchange the Rights, in whole or in part, at an exchange rate of one share of common stock, or other property deemed to have the same value, per Right, subject to certain adjustments.

Upon exercise of the Rights, the Company may need additional regulatory approvals to satisfy the requirements of the Rights Agreement. The Rights will expire on July 31, 2018, unless earlier than that date, they are exchanged or redeemed or the Plan is amended to extend the expiration date.

Stock Option and Stock Award Plans

Transactions involving option shares 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, 2012	1,282,718	$ 33.64		
Granted in 2013		$		
Exercised in 2013	(479,218)	$ 31.84		
Forfeited in 2013		$		
Outstanding at September 30, 2013	803,500	$ 34.71	2.50	$ 27,357
Option shares exercisable at September 30, 2013	803,500	$ 34.71	2.50	$ 27,357
Option shares available for future grant at September 30, 2013(1)	1,156,477			

(1) Includes shares available for SARs and restricted stock grants.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Transactions 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, 2012	1,628,153	$ 44.95		
Granted in 2013	412,970	$ 53.05		
Exercised in 2013	(32,419)	$ 35.59		
Forfeited in 2013		$		
Canceled in 2013(1)	(6,000)	$ 58.99		
Outstanding at September 30, 2013	2,002,704	$ 46.73	6.72	$ 44,124
SARs exercisable at September 30, 2013	1,348,724	$ 42.89	5.74	$ 34,888

(1) Shares were canceled during 2013 due to performance condition not being met.

Restricted Share Awards

Transactions 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, 2012	162,035	$ 53.07
Granted in 2013		$
Vested in 2013	(34,582)	$ 58.17
Forfeited in 2013		$
Outstanding at September 30, 2013	127,453	$ 51.69

Vesting restrictions for the outstanding shares of non-vested restricted stock at September 30, 2013 will lapse as follows: 2014 34,601 shares; 2015 32,852 shares; 2016 5,000 shares; 2018 35,000 shares; and 2021 20,000 shares.

Restricted Stock Units

Transactions 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, 2012	105,900	$ 51.61
Granted in 2013	44,200	$ 51.11
Vested in 2013		$
Forfeited in 2013	(6,600)	$ 49.98
Outstanding at September 30, 2013	143,500	$ 51.53

Vesting restrictions for the non-performance based restricted stock units outstanding at September 30, 2013 will lapse as follows: 2014 12,432 units; 2015 34,300 units; 2016 47,834 units; 2017 35,400 units; and 2018 13,534 units.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Transactions involving 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, 2012		$
Granted in 2013	255,604	$ 49.51
Vested in 2013		$
Forfeited in 2013		$
Outstanding at September 30, 2013	255,604	$ 49.51

Vesting restrictions will lapse during fiscal 2016 for the 255,604 performance based restricted stock units outstanding at September 30, 2013.

Redeemable Preferred Stock

As of September 30, 2013, 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 2013	2012
	(Thousands)	
Medium-Term Notes(1):		
7.4% due March 2023 to June 2025	$ 99,000	$ 99,000
Notes(1)(3):		
3.75% to 8.75% due April 2018 to March 2023	1,550,000	1,300,000
Total Long-Term Debt	1,649,000	1,399,000
Less Current Portion(2)		250,000
	$ 1,649,000	$ 1,149,000

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

(2)

None of the Company s long-term debt at September 30, 2013 will mature within the following twelve-month period. Current Portion of Long-Term Debt at September 30, 2012 consisted of $250.0 million of 5.25% notes that matured in March 2013.

(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.

On February 15, 2013, the Company issued $500.0 million of 3.75% notes due March 1, 2023. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $495.4 million. The proceeds of this debt issuance were used to refund the $250.0 million of 5.25% notes that matured in March 2013, as well as for general corporate purposes, including the reduction of short-term debt.

On December 1, 2011, the Company issued $500.0 million of 4.90% notes due December 1, 2021. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $496.1

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

million. The proceeds of this debt issuance were used for general corporate purposes, including refinancing short-term debt that was used to pay the $150.0 million due at the maturity of the Company s 6.70% notes in November 2011.

As of September 30, 2013, the aggregate principal amounts of long-term debt maturing during the next five years and thereafter are as follows: zero for 2014 through 2017, $300.0 million in 2018 and $1,349.0 million thereafter.

Short-Term Borrowings

The Company historically has obtained short-term funds either through bank loans or the issuance of commercial paper. As for the former, the Company maintains a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under these lines of credit are made at competitive market rates. These credit lines, which totaled $335.0 million, are revocable at the option of the financial institutions and are reviewed on an annual basis. The Company anticipates that its uncommitted lines of credit generally will be renewed at amounts near current levels, or substantially replaced by similar lines. The total amount available to be issued under the Company s commercial paper program is $300.0 million. The commercial paper program is backed by a syndicated committed credit facility totaling $750.0 million, which commitment extends through January 6, 2017.

The Company did not have any outstanding commercial paper and short-term notes payable to banks at September 30, 2013. At September 30, 2012, the Company had outstanding commercial paper and short-term notes payable to banks of $165.0 million and $6.0 million, respectively. At September 30, 2012, the weighted average interest rate on the commercial paper was 0.50% and the weighted average interest rate on the short-term notes payable to banks was 0.60%.

Debt Restrictions

Under the committed credit facility, the Company agreed that its debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter through January 6, 2017. At September 30, 2013, the Company s debt to capitalization ratio (as calculated under the facility) was .43. The constraints specified in the committed credit facility would have permitted an additional $2.42 billion in short-term and/or long-term debt to be outstanding (further limited by the indenture covenants discussed below) before the Company s debt to capitalization ratio exceeded .65.

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

Under the Company s existing indenture covenants, at September 30, 2013, the Company would have been permitted to issue up to a maximum of $1.6 billion in additional long-term unsecured indebtedness at then current market interest rates in addition to being able to issue new indebtedness to replace maturing debt. The Company s present liquidity position is believed to be adequate to satisfy known demands. However, if the Company were to experience a significant loss in the future (for example, as a result of an impairment of oil and gas properties), it is possible, depending on factors including the magnitude of the loss, that these indenture covenants would restrict the Company s ability to issue additional long-term unsecured indebtedness for a period of up to nine calendar months, beginning with the fourth calendar month following the loss. This would not at any time preclude the Company from issuing new indebtedness to replace maturing debt.

NATIONAL FUEL GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The Company s 1974 indenture pursuant to which $99.0 million (or 6.0%) of the Company s long-term debt (as of September 30, 2013) was issued, contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement, or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

The Company s $750.0 million committed credit facility also contains a cross-default provision whereby the failure by the Company or its significant subsidiaries to make payments under other borrowing arrangements, or the occurrence of certain events affecting those other borrowing arrangements, could trigger an obligation to repay any amounts outstanding under the committed credit facility. In particular, a repayment obligation could be triggered if (i) the Company or any of its significant subsidiaries fails to make a payment when due of any principal or interest on any other indebtedness aggregating $40.0 million or more, or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $40.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of September 30, 2013, the Company had no debt outstanding under the committed credit facility.

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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2013 and 2012. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

	At Fair Value as of September 30, 2013				
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
			(Dollars in thousands)		
Assets:					
Cash Equivalents Money Market Mutual Funds	$ 51,332	$	$	$	$ 51,332
Derivative Financial Instruments:					
Commodity Futures Contracts Gas	2,552			(1,641)	911
Over the Counter Swaps Gas		55,401		(3,945)	51,456
Over the Counter Swaps Oil		1,669		(5,058)	(3,389)
Other Investments:					
Balanced Equity Mutual Fund	31,813				31,813
Common Stock Financial Services Industry	6,544				6,544
Other Common Stock	330				330
Hedging Collateral Deposits	1,094				1,094
Total	$ 93,665	$ 57,070	$	$ (10,644)	$ 140,091
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts Gas	$ 1,641	$	$	$ (1,641)	$
Over the Counter Swaps Gas		701		(3,945)	(3,244)
Over the Counter Swaps Oil		3,751	5,190	(5,058)	3,883
Total	$ 1,641	$ 4,452	$ 5,190	$ (10,644)	$ 639
Total Net Assets/(Liabilities)	$ 92,024	$ 52,618	$ (5,190)	$	$ 139,452

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Recurring Fair Value Measures	At Fair Value as of September 30, 2012 Level 1	Level 2	Level 3	Netting Adjustments(1)	Total(1)
	(Dollars in thousands)				
Assets:					
Cash Equivalents Money Market Mutual Funds	$ 46,113	$	$	$	$ 46,113
Derivative Financial Instruments:					
Commodity Futures Contracts Gas	4,348			(2,760)	1,588
Over the Counter Swaps Gas		41,751		(15,723)	26,028
Over the Counter Swaps Oil			559	(559)	
Other Investments:					
Balanced Equity Mutual Fund	24,767				24,767
Common Stock Financial Services Industry	4,758				4,758
Other Common Stock	272				272
Hedging Collateral Deposits	364				364
Total	$ 80,622	$ 41,751	$ 559	$ (19,042)	$ 103,890
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts Gas	$ 2,760	$	$	$ (2,760)	$
Over the Counter Swaps Gas		19,932		(15,723)	4,209
Over the Counter Swaps Oil		654	20,223	(559)	20,318
Total	$ 2,760	$ 20,586	$ 20,223	$ (19,042)	$ 24,527
Total Net Assets/(Liabilities)	$ 77,862	$ 21,165	$ (19,664)	$	$ 79,363

(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. In the tables above, presenting asset and liability information by gas and oil positions may result in negative assets or negative liabilities in the Total column when a counterparty has issued both gas and oil swaps to the Company.

Derivative Financial Instruments

At September 30, 2013 and 2012, 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 $1.1 million (at September 30, 2013) and $0.4 million (at September 30, 2012), 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, 2013 and 2012 consist of natural gas price swap agreements used in the Company s Exploration and Production and Energy Marketing segments and a portion of the crude oil price swap agreements used in the Company s Exploration and Production segment. The fair value of the Level 2 price swap agreements is based on an internal, discounted cash flow model that uses observable inputs (i.e. LIBOR based discount rates and basis differential information, if applicable, at active natural gas and crude oil trading markets). The derivative financial instruments reported in Level 3 consist of a portion of the crude oil price swap agreements used in the Company s Exploration and Production segment at September 30, 2013 and 2012. The fair value of the Level 3 crude oil price swap agreements is based on an internal, discounted cash flow model that uses both observable (i.e. LIBOR based discount rates) and unobservable inputs (i.e. basis differential information of crude oil trading markets with low trading volume).

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

The significant unobservable input used in the fair value measurement of a portion of the Company s over-the-counter crude oil swaps is the basis differential between Midway Sunset oil and NYMEX contracts. Significant changes in the assumed basis differential could result in a significant change in the value of the derivative financial instruments. At September 30, 2013, it was assumed that Midway Sunset oil was 106.4% of NYMEX. This is based on a historical twelve month average of Midway Sunset oil sales verses NYMEX settlements. During this twelve-month period, the price of Midway Sunset oil ranged from 97.1% to 112.4% of NYMEX. If the basis differential between Midway Sunset oil and NYMEX contracts used in the fair value measurement calculation at September 30, 2013 had been 10 percentage points higher, the fair value of the Level 3 crude oil price swap agreements liability would have been approximately $5.3 million higher. If the basis differential between Midway Sunset oil and NYMEX contracts used in the fair value measurement at September 30, 2013 had been 10 percentage points lower, the fair value measurement of the Level 3 crude oil price swap agreements liability would have changed from a net liability of $5.2 million to a net asset of $0.9 million. These calculated amounts are based solely on basis differential changes and do not take into account any other changes to the fair value measurement calculation.

The accounting rules for fair value measurements and disclosures require consideration of the impact of nonperformance risk (including credit risk) from a market participant perspective in the measurement of the fair value of assets and liabilities. At September 30, 2013, the Company determined that nonperformance risk would have no material impact on its financial position or results of operation. To assess nonperformance risk, the Company considered information such as any applicable collateral posted, master netting arrangements, and applied a market-based method by using the counterparty (for an asset) or the Company s (for a liability) credit default swaps rates.

The tables listed below provide reconciliations of the beginning and ending net balances for assets and liabilities measured at fair value and classified as Level 3 for the years ended September 30, 2013 and September 30, 2012, respectively. For the years ended September 30, 2013 and September 30, 2012, no transfers in or out of Level 1 or Level 2 occurred. There were no purchases or sales of derivative financial instruments during the periods presented in the tables below. All settlements of the derivative financial instruments are reflected in the Gains/Losses Realized and Included in Earnings column of the tables below.

Fair Value Measurements Using Unobservable Inputs (Level 3)

		Total Gains/Losses			
	October 1, 2012	(Gains)/Losses Realized and Included in Earnings	Gains/(Losses) Unrealized and Included in Other Comprehensive Income (Loss)	Transfer In/(Out) of Level 3	September 30, 2013
			(Dollars in thousands)		
Derivative Financial Instruments(2)	$ (19,664)	$ 13,408(1)	$ 1,066	$	$ (5,190)

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the year ended September 30, 2013.

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

Fair Value Measurements Using Unobservable Inputs (Level 3)

	October 1, 2011	Total Gains/Losses (Gains)/Losses Realized and Included in Earnings	Gains/(Losses) Unrealized and Included in Other Comprehensive Income (Loss)	Transfer In/(Out) of Level 3	September 30, 2012
			(Dollars in thousands)		
Derivative Financial Instruments(2)	$ (5,410)	$ 46,174(1)	$ (60,428)	$	$ (19,664)

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the year ended September 30, 2012.

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

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 2013 Carrying Amount	2013 Fair Value	2012 Carrying Amount	2012 Fair Value
		(Thousands)		
Long-Term Debt	$ 1,649,000	$ 1,767,519	$ 1,399,000	$ 1,623,847

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.

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

Other Investments

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

Other investments include cash surrender values of insurance contracts (net present value in the case of split-dollar collateral assignment arrangements) and marketable equity securities. The values of the insurance

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

contracts amounted to $57.6 million and $57.0 million at September 30, 2013 and 2012, respectively. The fair value of the equity mutual fund was $31.8 million and $24.8 million at September 30, 2013 and 2012, respectively. The gross unrealized gain on this equity mutual fund was $5.7 million at September 30, 2013 and $2.6 million at September 30, 2012. The fair value of the stock of an insurance company was $6.5 million and $4.8 million at September 30, 2013 and 2012, respectively. The gross unrealized gain on this stock was $4.1 million and $2.3 million at September 30, 2013 and 2012, respectively. The insurance contracts and marketable equity securities are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees.

Derivative Financial Instruments

The Company uses derivative instruments to manage commodity price risk in the Exploration and Production and Energy Marketing segments. During 2012, the Pipeline and Storage segment discontinued its use of derivative instruments as a means of managing commodity price risk. 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. The Company also enters into futures contracts and swaps to manage the risk associated with forecasted gas purchases, forecasted gas sales, storage of gas, withdrawal of gas from storage to meet customer demand and the potential decline in the value of gas held in storage. The duration of the Company s hedges does not typically exceed 5 years.

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, 2013 and September 30, 2012. All of the derivative financial instruments reported on those line items relate to commodity contracts.

Cash Flow Hedges

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

As of September 30, 2013, the Company s Exploration and Production segment had the following commodity derivative contracts (swaps) outstanding to hedge forecasted sales (where the Company uses short positions (i.e. positions that pay-off in the event of commodity price decline) to mitigate the risk of decreasing revenues and earnings):

Commodity	Units
Natural Gas	213.3 Bcf (all short positions)
Crude Oil	3,603,000 Bbls (all short positions)

As of September 30, 2013, the Company s Energy Marketing segment had the following commodity derivative contracts (futures contracts and swaps) outstanding to hedge forecasted sales (where the Company uses short positions to mitigate the risk associated with natural gas price decreases and its impact on decreasing revenues and earnings) and, when applicable, purchases (where the Company uses long positions (i.e. positions that pay-off in the event of commodity price increases) to mitigate the risk of increasing natural gas prices, which would lead to increased purchased gas expense and decreased earnings):

Commodity	Units
Natural Gas	6.8 Bcf (6.4 Bcf short positions (mostly forecasted storage withdrawals) and 0.4 Bcf long positions (mostly forecasted storage injections))

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

As of September 30, 2013, the Company s Exploration and Production segment had $51.1 million ($29.4 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that $24.1 million ($13.9 million after tax) of such unrealized gains will be reclassified into the Consolidated Statement of Income within the next 12 months as the expected sales of the underlying commodities occur.

As of September 30, 2013, the Company s Energy Marketing segment had $2.1 million ($1.3 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that the full amount will be reclassified into the Consolidated Statement of Income within the next 12 months as the expected sales of the underlying commodity occurs.

Refer to Note A, under Accumulated Other Comprehensive Income (Loss), for the after-tax gain (loss) pertaining to derivative financial instruments for the Exploration and Production and Energy Marketing segments.

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Year Ended September 30, 2013 and 2012 (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,**	
		2013	**2012**		**2013**	**2012**		**2013**	**2012**
Commodity Contracts Production segment	Exploration &	$ 87,813	$ (11,776)	Operating Revenue	$ 39,666	$ 54,777	Operating Revenue	$ (2,045)	$
Commodity Contracts segment	Energy Marketing	$ 3,977	$ 4,725	Purchased Gas	$ (920)	$ 10,439	Not Applicable	$	$
Commodity Contracts segment(1)	Pipeline & Storage	$	$ (197)	Operating Revenue	$ (672)	$ 475	Not Applicable	$	$
Total		$ 91,790	$ (7,248)		$ 38,074	$ 65,691		$ (2,045)	$

(1) There were no open hedging positions at September 30, 2013 or 2012.

Fair Value Hedges

The Company s Energy Marketing segment 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

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natural gas held in storage. With respect to fixed price sales commitments, the Company enters into long positions to mitigate the risk of price increases for natural gas supplies that could occur after the Company enters into fixed price sales agreements with its customers. With respect to fixed price purchase commitments, the Company enters into short positions to mitigate the risk of price decreases that could occur after the Company locks into fixed price purchase deals with its suppliers. With respect to storage hedges, the Company enters into short positions to mitigate the risk of price decreases that could result in a lower of cost or market writedown of the value of natural gas in storage that is recorded in the Company s financial statements. As of September 30, 2013, the Company s Energy Marketing segment had fair value hedges covering approximately 9.7 Bcf (8.8 Bcf of fixed price sales commitments (mostly long positions), 0.8 Bcf of fixed price purchase commitments (mostly short positions) and 0.1 Bcf of commitments related to the withdrawal of storage gas (all short positions)). 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 Energy Marketing segment	**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, 2013**	**Amount of Gain or (Loss) on Hedged Item Recognized in the Consolidated Statement of Income for the Year Ended September 30, 2013**
		(In thousands)	
Commodity Contracts Hedge of fixed price sales commitments of natural gas	Operating Revenues	$ (1,759)	$ 1,759
Commodity Contracts Hedge of fixed price purchase commitments of natural gas	Purchased Gas	(268)	268
Commodity Contracts Hedge of natural gas held in storage	Purchased Gas	13	(13)
		$ (2,014)	**$ 2,014**

Economic Hedges

For derivative instruments that do not qualify as either a cash flow hedge or fair value hedge, all gains and losses are recognized in the Consolidated Statement of Income. As of September 30, 2013, the Company s Exploration and Production segment had derivative contracts (swaps) outstanding to hedge forecasted sales of 696,000 Bbls of crude oil (where the Company uses short positions (i.e. positions that pay-off in the event of commodity price decline) to mitigate the risk of decreasing revenues and earnings). The Company did not have any economic hedges during 2012 or 2011. The aggregate derivative loss associated with such contracts for the year ended September 30, 2013 was $1.7 million. This loss was reported as a component of Operating Revenues in the Consolidated Statement of Income.

Credit Risk

The Company may be exposed to credit risk on any of the derivative financial instruments that are in a gain position. Credit risk relates to the risk of loss that the Company would incur as a result of nonperformance by counterparties pursuant to the terms of their contractual obligations. To mitigate such credit risk, management performs a credit check, and then on a quarterly basis monitors counterparty credit exposure. The majority of the Company s counterparties are financial institutions and energy traders. The Company has over-the-counter swap positions with thirteen counterparties of which eleven are in a net gain position. On average, the Company had $4.4 million of credit exposure per counterparty in a gain position at

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

September 30, 2013. The maximum credit exposure per counterparty in a gain position at September 30, 2013 was $8.1 million. As of September 30, 2013, the Company had not received any collateral from the counterparties. 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, 2013, eleven of the thirteen counterparties to the Company s outstanding derivative instrument contracts (specifically the over-the-counter swaps) had a common credit-risk related contingency feature. In the event the Company s credit rating increases or falls below a certain threshold (applicable debt ratings), the available credit extended to the Company would either increase or decrease. A decline in the Company s credit rating, in and of itself, would not cause the Company to be required to increase the level of its hedging collateral deposits (in the form of cash deposits, letters of credit or treasury debt instruments). If the Company s outstanding derivative instrument contracts were in a liability position (or if the liability were larger) and/or the Company s credit rating declined, then additional hedging collateral deposits may be required. At September 30, 2013, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $34.7 million according to the Company s internal model (discussed in Note F Fair Value Measurements). At September 30, 2013, the fair market value of the derivative financial instrument liabilities with a credit-risk related contingency feature was $0.6 million according to the Company s internal model (discussed in Note F Fair Value Measurements). For its over-the-counter swap agreements, the Company was not required to post any hedging collateral deposits at September 30, 2013.

For its exchange traded futures contracts, which are in an asset position, the Company was required to post $1.1 million in hedging collateral deposits as of September 30, 2013. As these are exchange traded futures contracts, there are no specific credit-risk related contingency features. The Company posts hedging collateral based on open positions and margin requirements it has with its counterparties.

The Company s requirement to post hedging collateral deposits 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 $1.2 million, $0.9 million and $0.7 million for the years ended September 30, 2013, 2012 and 2011, 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 $4.4 million, $4.3 million, and $4.3 million for the years ended September 30, 2013, 2012 and 2011, 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.

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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 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.

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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 year 2013, 2012 and 2011.

	Retirement Plan Year Ended September 30			Other Post-Retirement Benefits Year Ended September 30		
	2013	2012	2011	2013	2012	2011
			(Thousands)			
Change in Benefit Obligation						
Benefit Obligation at Beginning of Period	$ 1,070,744	$ 949,777	$ 924,493	$ 561,263	$ 485,452	$ 472,407
Service Cost	15,846	14,202	14,772	4,705	4,016	4,276
Interest Cost	36,498	41,526	42,676	19,212	21,315	21,884
Plan Participants Contributions				2,141	1,956	1,963
Retiree Drug Subsidy Receipts				1,526	1,528	1,532
Amendments(1)			(1,764)			(7,187)
Actuarial (Gain) Loss	(121,631)	120,338	21,395	(104,455)	71,708	15,071
Benefits Paid	(55,152)	(55,099)	(51,795)	(23,758)	(24,712)	(24,494)
Benefit Obligation at End of Period	$ 946,305	$ 1,070,744	$ 949,777	$ 460,634	$ 561,263	$ 485,452
Change in Plan Assets						
Fair Value of Assets at Beginning of Period	$ 701,676	$ 601,719	$ 597,549	$ 414,134	$ 351,990	$ 353,269
Actual Return on Plan Assets	98,783	111,034	2,412	61,715	63,552	(4,094)
Employer Contributions	54,000	44,022	53,553	18,160	21,348	25,346
Plan Participants Contributions				2,141	1,956	1,963
Benefits Paid	(55,152)	(55,099)	(51,795)	(23,758)	(24,712)	(24,494)
Fair Value of Assets at End of Period	$ 799,307	$ 701,676	$ 601,719	$ 472,392	$ 414,134	$ 351,990
Net Amount Recognized at End of Period (Funded Status)	$ (146,998)	$ (369,068)	$ (348,058)	$ 11,758	$ (147,129)	$ (133,462)
Amounts Recognized in the Balance Sheets Consist of:						
Non-Current Liabilities	$ (146,998)	$ (369,068)	$ (348,058)	$ (11,016)	$ (147,129)	$ (133,462)
Non-Current Assets				22,774		
Net Amount Recognized at End of Period	$ (146,998)	$ (369,068)	$ (348,058)	$ 11,758	$ (147,129)	$ (133,462)
Accumulated Benefit Obligation	$ 886,942	$ 986,223	$ 874,595	N/A	N/A	N/A
Weighted Average Assumptions Used to Determine Benefit Obligation at September 30						
Discount Rate	4.75%	3.50%	4.50%	4.75%	3.50%	4.50%
Rate of Compensation Increase	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

	Retirement Plan Year Ended September 30			Other Post-Retirement Benefits Year Ended September 30		
	2013	**2012**	**2011**	**2013**	**2012**	**2011**
	(Thousands)					
Components of Net Periodic Benefit Cost						
Service Cost	$ 15,846	$ 14,202	$ 14,772	$ 4,705	$ 4,016	$ 4,276
Interest Cost	36,498	41,526	42,676	19,212	21,315	21,884
Expected Return on Plan Assets	(57,346)	(59,701)	(59,103)	(32,872)	(28,971)	(29,165)
Amortization of Prior Service Cost (Credit)	238	269	588	(2,138)	(2,138)	(1,710)
Amortization of Transition Amount				8	10	541
Recognition of Actuarial Loss(2)	52,776	39,615	34,873	20,892	24,057	23,794
Net Amortization and Deferral for Regulatory Purposes	(10,406)	(6,900)	(2,311)	11,844	6,162	10,490
Net Periodic Benefit Cost	$ 37,606	$ 29,011	$ 31,495	$ 21,651	$ 24,451	$ 30,110
Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost at September 30						
Discount Rate	3.50%	4.50%	4.75%	3.50%	4.50%	4.75%
Expected Return on Plan Assets	8.00%	8.25%	8.25%	8.00%	8.25%	8.25%
Rate of Compensation Increase	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%

(1) In fiscal 2011, the Company passed an amendment which changed the definition of annual compensation prospectively to exclude certain bonuses paid by Seneca after September 30, 2011. This decreased the benefit obligation of the Retirement Plan. In fiscal 2011, the Company also increased the prescription drug co-payments for certain retired participants which decreased the benefit obligation of the other post-retirement benefits.

(2) 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 cost associated with these plans were $9.6 million, $9.1 million and $8.6 million in 2013, 2012 and 2011, respectively. The accumulated benefit obligations for the plans were $57.2 million, $54.5 million and $46.0 million at September 30, 2013,

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2012 and 2011, respectively. The projected benefit obligations for the plans were $77.1 million, $88.5 million and $79.2 million at September 30, 2013, 2012 and 2011, respectively. The projected benefit obligations are recorded in Other Deferred Credits on the Consolidated Balance Sheets. The actuarial valuations for the plans were determined based on a discount rate of 3.75%, 2.50% and 3.75% as of September 30, 2013, 2012 and 2011, respectively and a weighted average rate of compensation increase of 7.75%, 7.75% and 8.0% as of September 30, 2013, 2012 and 2011, respectively.

The cumulative amounts recognized in accumulated other comprehensive income (loss), regulatory assets, and regulatory liabilities through fiscal 2013, the changes in such amounts during 2013, as well as the amounts expected to be recognized in net periodic benefit cost in fiscal 2014 are presented in the table below:

	Retirement Plan	Other Post-Retirement Benefits (Thousands)	Non-Qualified Benefit Plans
Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities(1)			
Net Actuarial Loss	$ (242,282)	$ (41,115)	$ (21,116)
Prior Service (Cost) Credit	(1,066)	9,079	
Net Amount Recognized	$ (243,348)	$ (32,036)	$ (21,116)
Changes to Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities Recognized During Fiscal 2013(1)			
Decrease in Actuarial Loss, excluding amortization(2)	$ 163,067	$ 133,298	$ 14,373
Change due to Amortization of Actuarial Loss	52,776	20,892	5,280
Reduction in Transition Obligation		8	
Prior Service (Cost) Credit	238	(2,138)	
Net Change	$ 216,081	$ 152,060	$ 19,653
Amounts Expected to be Recognized in Net Periodic Benefit Cost in the Next Fiscal Year(1)			
Net Actuarial Loss	$ (36,007)	$ (2,645)	$ (3,008)
Prior Service (Cost) Credit	(210)	2,138	
Net Amount Expected to be Recognized	$ (36,217)	$ (507)	$ (3,008)

(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, 2013, the Company recorded a $316.6 million decrease to Other Regulatory Assets in the Company s Utility and Pipeline and Storage segments and a $71.2 million (pre-tax) decrease to Accumulated Other Comprehensive Loss.

The effect of the discount rate change for the Retirement Plan in 2013 was to decrease the projected benefit obligation of the Retirement Plan by $147.9 million. In 2013, other actuarial experience increased the projected benefit obligation for the Retirement Plan by $26.3 million, primarily attributable to a change in

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

the mortality assumption. The effect of the discount rate change for the Retirement Plan in 2012 was to increase the projected benefit obligation of the Retirement Plan by $118.8 million. The effect of the discount rate change for the Retirement Plan in 2011 was to increase the projected benefit obligation of the Retirement Plan by $26.9 million.

The Company made cash contributions totaling $54.0 million to the Retirement Plan during the year ended September 30, 2013. The Company expects that the annual contribution to the Retirement Plan in 2014 will be in the range of $30.0 million to $40.0 million. Changes in the discount rate, other actuarial assumptions, and asset performance could ultimately cause the Company to fund larger amounts to the Retirement Plan in 2014 in order to be in compliance with the Pension Protection Act of 2006 (as impacted by the Moving Ahead for Progress in the 21st Century Act). In July 2012, the Surface Transportation Extension Act, which is also referred to as the Moving Ahead for Progress in the 21st Century Act (the Act), was passed by Congress and signed by the President. The Act included pension funding stabilization provisions. The Company is continually evaluating its future contributions in light of the provisions of the Act.

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: $57.9 million in 2014; $58.7 million in 2015; $59.7 million in 2016; $60.6 million in 2017; $61.6 million in 2018; and $322.9 million in the five years thereafter.

The effect of the discount rate change in 2013 was to decrease the other post-retirement benefit obligation by $75.9 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2013 by $28.6 million as the increase in obligation attributable to the change in mortality assumption was more than offset by the decrease in obligation attributable to a revision in assumed per-capita claims cost, premiums and participant contributions based on actual experience.

The effect of the discount rate change in 2012 was to increase the other post-retirement benefit obligation by $65.6 million. Other actuarial experience increased the other post-retirement benefit obligation in 2012 by $6.1 million.

The effect of the discount rate change in 2011 was to increase the other post-retirement benefit obligation by $14.5 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2011 by $6.6 million, primarily attributable to the impact of the change in prescription drug co-payments as noted above.

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. Since the Company is assumed to continue to provide a prescription drug benefit to retirees in the point of service and indemnity plans that is at least actuarially equivalent to Medicare Part D, the impact of the Act was reflected as of December 8, 2003.

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
2014	$ 25,966	$ (1,893)
2015	$ 27,243	$ (2,093)
2016	$ 28,592	$ (2,290)
2017	$ 29,899	$ (2,476)
2018	$ 31,067	$ (2,673)
2019 through 2023	$ 169,996	$ (16,186)

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	2013	2012	2011
Rate of Increase for Pre Age 65 Participants	7.28%(1)	7.46%(1)	7.64%(1)
Rate of Increase for Post Age 65 Participants	6.78%(1)	6.84%(1)	6.89%(1)
Annual Rate of Increase in the Per Capita Cost of Covered Prescription Drug Benefits	7.78%(1)	8.08%(1)	8.39%(1)
Annual Rate of Increase in the Per Capita Medicare Part B Reimbursement	6.78%(1)	6.84%(1)	6.89%(1)
Annual Rate of Increase in the Per Capita Medicare Part D Subsidy	7.03%(1)	7.13%(1)	7.30%(1)

(1) It was assumed that this rate would gradually decline to 4.5% by 2028.

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, 2013 would increase by $55.5 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 2013 by $3.5 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, 2013 would decrease by $46.7 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 2013 by $2.9 million.

The Company made cash contributions totaling $18.1 million to its VEBA trusts and 401(h) accounts during the year ended September 30, 2013. 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, 2013. The Company expects that the annual contribution to its VEBA trusts and 401(h) accounts in 2014 will be in the range of $5.0 million to $15.0 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.

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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, 2013 and 2012, 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, 2013	Level 1	Level 2	Level 3
Retirement Plan Investments				
Domestic Equities(1)	$ 402,107	$ 271,071	$ 131,036	$
International Equities(2)	103,028	2,355	100,673	
Global Equities(3)	25,325		25,325	
Domestic Fixed Income(4)	163,750	71,185	92,565	
International Fixed Income(5)	2,762	1,318	1,444	
Global Fixed Income(6)	88,084		88,084	
Hedge Fund Investments	42,027			42,027
Real Estate	2,723			2,723
Cash and Cash Equivalents	22,694		22,694	
Total Retirement Plan Investments	852,500	345,929	461,821	44,750
401(h) Investments	(49,453)	(20,141)	(26,706)	(2,606)
Total Retirement Plan Investments (excluding 401(h) Investments)	$ 803,047	$ 325,788	$ 435,115	$ 42,144
Miscellaneous Accruals, Interest Receivables, and Non-Interest Cash	(3,740)			
Total Retirement Plan Assets	$ 799,307			

	Total Fair Value Amounts at September 30, 2012	Level 1	Level 2	Level 3
Retirement Plan Investments				
Domestic Equities(1)	$ 350,137	$ 231,978	$ 118,159	$
International Equities(2)	83,659	2,090	81,569	
Global Equities(3)	21,335		21,335	
Domestic Fixed Income(4)	140,010	70,730	69,280	
International Fixed Income(5)	2,816	1,941	875	
Global Fixed Income(6)	88,138		88,138	
Hedge Fund Investments	39,956			39,956
Real Estate	6,170			6,170
Cash and Cash Equivalents	12,874		12,874	
Total Retirement Plan Investments	745,095	306,739	392,230	46,126

401(h) Investments		(43,311)	(17,818)	(22,813)	(2,680)
Total Retirement Plan Investments (excluding 401(h) Investments)	$	701,784	$ 288,921	$ 369,417	$ 43,446
Miscellaneous Accruals, Interest Receivables, and Non-Interest Cash		(108)			
Total Retirement Plan Assets	$	701,676			

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(1) Domestic Equities include mostly collective trust funds, common stock, and exchange traded funds.

(2) International Equities include mostly collective trust funds and common stock.

(3) Global Equities are comprised of a collective trust fund.

(4) Domestic Fixed Income securities include mostly collective trust funds, corporate/government bonds and mortgages, and exchange traded funds.

(5) International Fixed Income securities include mostly collective trust funds and exchange traded funds.

(6) Global Fixed Income securities are comprised of a collective trust fund.

	Total Fair Value Amounts at September 30, 2013	Level 1	Level 2	Level 3
Other Post-Retirement Benefit Assets held in VEBA Trusts				