UNITED STATES SECURITIES AND EXCHANGE CO[redacted]

Washington, D.C. 20549

Form 10-K

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

For the Fiscal Year Ended September 30, 2012

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

For the Transition Period from to

Commission File Number 1-3880

National Fuel Gas Company

(Exact name of registrant as specified in its charter)

New Jersey	**13-1086010**
(State or other jurisdiction of incorporation or organization)	*(I.R.S. Employer Identification No.)*
6363 Main Street Williamsville, New York	**14221**
(Address of principal executive offices)	*(Zip Code)*

(716) 857-7000

Registrant's telephone number, including area code

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

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

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

None

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

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

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

Indicate by check mark whether the registrant has submitted electronically 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 ☑ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, 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 ☑ 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 ☑

The aggregate market value of the voting stock held by nonaffiliates of the registrant amounted to $3,890,757,000 as of March 31, 2012.

Common Stock, par value $1.00 per share, outstanding as of October 31, 2012: 83,374,585 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for its 2013 Annual Meeting of Stockholders, to be filed with the Securities and Exchange Commission within 120 days of September 30, 2012, are incorporated by reference into Part III of this report.

Glossary of Terms

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

National Fuel Gas Companies

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

Distribution Corporation National Fuel Gas Distribution Corporation

Empire Empire Pipeline, Inc.

ESNE Energy Systems North East, LLC

Highland Highland Forest Resources, Inc.

Horizon Horizon Energy Development, 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

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.

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.

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.

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.

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.

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

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.

For the Fiscal Year Ended September 30, 2012

CONTENTS

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 four 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 732,600 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, 2012, Seneca had U.S. proved developed and undeveloped reserves of 42,862 Mbbl of oil and 988,434 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.

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 K — Business Segment Information.

The Company's other direct wholly owned subsidiaries or businesses are not included in any of the four reported business segments and include the following active companies:

- Seneca's Northeast Division, which markets timber from Appalachian land holdings. At September 30, 2012, the Company owned approximately 95,000 acres of timber property and managed approximately 3,000 additional acres of timber cutting rights; and
- National Fuel Gas Midstream Corporation (Midstream Corporation), a Pennsylvania corporation formed to build, own and operate natural gas processing and pipeline gathering facilities in the Appalachian region.

No single customer, or group of customers under common control, accounted for more than 10% of the Company's consolidated revenues in 2012.

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 26.6% of the Company's 2012 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 27.5% of the Company's 2012 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 43.5% of the total firm storage capacity, and the Energy Marketing segment accounts for another 4,810 MDth or 7.0% of the total firm storage capacity. Nonaffiliated customers have contracted for the remaining 33,840 MDth or 49.5% 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 2013, 79.7% of Supply Corporation's total firm storage capacity was committed under contracts that, subject to 2012 shipper or Supply Corporation notifications, could have been terminated effective in 2013. Supply Corporation received storage contract termination notifications in 2012 totaling approximately 2,115 MDth of storage capacity. Supply Corporation expects to remarket this capacity with service beginning April 1, 2013.

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 2,175 MDth per day (contracted transportation capacity), compared to 2,115 MDth per day last year. The Utility segment accounts for approximately 1,045 MDth per day or 48.0% of contracted transportation capacity, and the Energy Marketing and Exploration and Production segments represent another 181 MDth per day or 8.3% of contracted transportation capacity. The remaining 949 MDth or 43.7% of contracted transportation capacity is subject to firm contracts with nonaffiliated customers.

At the beginning of 2013, 50.1% of Supply Corporation's contracted transportation capacity was committed under affiliate contracts that were scheduled to expire in 2013 or, subject to 2012 shipper or Supply Corporation notifications, could have been terminated effective in 2013. Based on contract expirations and termination notices received in 2012 for 2013 termination, and taking into account any known contract additions, contracted transportation capacity with affiliates is expected to decrease 1.7% in 2013. Similarly, 23.6% of contracted transportation capacity was committed under unaffiliated shipper contracts that were scheduled to expire in 2013 or, subject to 2012 shipper or Supply Corporation notifications, could have been terminated effective in 2013. Based on contract expirations and termination notices received in 2012 for 2013 termination, and taking into account any known contract additions, contracted transportation capacity with unaffiliated shippers is expected to increase 36.2% in 2013. The relatively high price of natural gas supplies available at Supply Corporation's receipt point on the United States/Canadian border at Niagara, together with shifting gas supply dynamics, have reduced the amount of firm capacity Supply Corporation contracts from Niagara. However, Supply Corporation has been successful in marketing and obtaining long-term firm contracts for transportation capacity designed to move Marcellus Shale production to market. For example, in 2012, Supply Corporation added 160 MDth per day of contracted incremental transportation associated with its Line N 2011 project, and in 2013, Supply Corporation expects to add 483 MDth per day of contracted incremental transportation associated with its Line N 2012 and Northern Access projects. Supply Corporation expects additional transportation contracts to commence in 2014.

At the beginning of 2013, Empire had service agreements in place for firm transportation capacity totaling up to approximately 950 MDth per day (including capacity on the Empire Connector and the Tioga County Extension), compared to 663 MDth per day at the beginning of 2012. 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 2013, most of Empire's firm contracted capacity (94.5%) was contracted as long-term full-year deals. Four of the long-term contracts will expire between October 31, 2012 and March 31, 2013, representing approximately 0.8% of Empire's firm contracted capacity. Included in Empire's long-term contracted firm capacity are two long-term agreements, representing 30.1% of Empire's firm contracted capacity, to move Marcellus Shale production via Empire's Tioga County Extension Expansion project. In addition, Empire has some seasonal (winter-only) contracts that extend for multiple years, representing 1.1% of Empire's firm contracted capacity. Two of those contracts will expire on March 31, 2013, representing 0.3% of Empire's firm contracted capacity. Arrangements for 3.7% of Empire's firm contracted capacity are single-year contracts. Five of those contracts expired on October 31, 2012, representing 2.4% of Empire's firm contracted capacity. The remainder of the single-year contracts can potentially expire in early 2014, depending on whether Empire issues or receives termination notices during 2013. The remaining 0.7% of Empire's firm contracted capacity is contracted under short-term contracts all of which terminated during October 2012. At the beginning of 2013, the Utility segment accounted for 4.5%

of Empire's firm contracted capacity, and the Energy Marketing segment accounted for 1.2% of Empire's firm contracted capacity, with the remaining 94.3% of Empire's firm contracted capacity subject to contracts with nonaffiliated customers.

The relatively high price of natural gas supplies available at Empire's receipt point on the United States/ Canadian border at Chippawa, together with shifting gas supply dynamics, have reduced the amount of firm capacity Empire contracts from Chippawa. However, Empire has been successful in marketing and obtaining long-term firm contracts for transportation capacity designed to move Marcellus Shale production to market. Specifically, as discussed above, in early 2012 Empire placed into service two long-term contracts for firm transportation service associated with its Tioga County Extension project. These two contracts are for increasing amounts of incremental firm capacity beginning in early 2013 at 270 MDth per day of firm contracted capacity and increasing over the next 7 months to 350 MDth per day of firm contracted capacity.

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

The Exploration and Production Segment

The Exploration and Production segment contributed approximately 43.9% of the Company's 2012 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 1.9% of the Company's 2012 net income available for common stock.

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

All Other Category and Corporate Operations

The All Other category and Corporate operations contributed approximately 0.1% of the Company's 2012 net income available for common stock.

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.

Discontinued Operations

In September 2010, the Company sold its landfill gas operations in the states of Ohio, Michigan, Kentucky, Missouri, Maryland and Indiana. The Company's landfill gas operations were maintained under the Company's wholly owned subsidiary, Horizon LFG, which owned and operated these short distance landfill gas pipeline companies. These operations are presented in the Company's financial statements as discontinued operations.

Additional discussion of the Company's discontinued operations appears 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 2012, the Utility segment purchased 56.6 Bcf of gas for delivery to its customers. Gas purchased from producers and suppliers in the United States and Canada under firm contracts (seasonal and longer) accounted for 42% of these purchases. Purchases of gas on the spot market (contracts for one month or less) accounted for 58% of the Utility segment's 2012 purchases. Purchases from Southwestern Energy Services Company (15%), South Jersey Resources Group, LLC (14%), Chevron Natural Gas (12%), Range Resources Appalachia, LLC (11%) and Tenaska Marketing Ventures (10%) accounted for 62% of the Utility's 2012 gas purchases. No other producer or supplier provided the Utility segment with more than 10% of its gas requirements in 2012.

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 K — Business Segment Information and Note N — 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 2012, this segment purchased 46.8 Bcf of gas, including 45.8 Bcf for delivery to its customers. The remaining 1.0 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 or in Canada.

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 21%, and in Pennsylvania, approximately 10%, 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 offer the opportunity for increased transportation services. Supply Corporation has developed its Northern Access and Line N pipeline expansion projects to receive natural gas produced from the 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.

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 1,874 full-time employees at September 30, 2012.

The Company has agreements in place with collective bargaining units in New York and Pennsylvania. Agreements covering employees in New York are scheduled to expire in February 2013. New agreements approved by the members of the New York collective bargaining units will take effect in February 2013 and expire in February 2017. Agreements covering employees in collective bargaining units in Pennsylvania are scheduled to expire in April 2014 and May 2014.

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, 2012(1)

Name and Age (as of November 15, 2012)	Current Company Positions and Other Material Business Experience During Past Five Years
David F. Smith (59)	Chairman of the Board of Directors of the Company since March 2010 and Chief Executive Officer of the Company since February 2008. Mr. Smith previously served as President of the Company from February 2006 through June 2010; Chief Operating Officer of the Company from February 2006 through January 2008; President of Supply Corporation from April 2005 through June 2008; and President of Empire from September 2005 through July 2008.
Ronald J. Tanski (60)	President and Chief Operating Officer of the Company since July 2010. Mr. Tanski previously served as Treasurer and Principal Financial Officer of the Company from April 2004 through June 2010; President of Supply Corporation from July 2008 through June 2010; President of Distribution Corporation from February 2006 through June 2008; and Treasurer of Distribution Corporation from April 2004 through July 2008.
Matthew D. Cabell (54)	Senior Vice President of the Company since July 2010 and President of Seneca since December 2006.
Anna Marie Cellino (59)	President of Distribution Corporation since July 2008. Ms. Cellino previously served as Secretary of the Company from October 1995 through June 2008; Secretary of Distribution Corporation from September 1999 through June 2008; and Senior Vice President of Distribution Corporation from July 2001 through June 2008.
John R. Pustulka (60)	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 (43)	Treasurer and Principal Financial Officer of the Company since July 2010; 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 (53)	Controller and Principal Accounting Officer of the Company since April 2004; and Controller of Distribution Corporation and Supply Corporation since April 2004.
Carl M. Carlotti (57)	Senior Vice President of Distribution Corporation since January 2008. Mr. Carlotti previously served as Vice President of Distribution Corporation from October 1998 to January 2008.
Paula M. Ciprich (52)	Secretary of the Company since July 2008; General Counsel of the Company since January 2005; Secretary of Distribution Corporation since July 2008. Ms. Ciprich previously served as Assistant Secretary of Distribution Corporation from February 1997 through June 2008.
Donna L. DeCarolis (53)	Vice President Business Development of the Company since October 2007.
James D. Ramsdell (57)	Senior Vice President 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.

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.

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.

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

The Company is subject to the jurisdiction of the FERC with respect to Supply Corporation, Empire and some transactions performed by other Company subsidiaries, including Seneca, Distribution Corporation and NFR. The FERC, among other things, approves the rates that Supply Corporation and Empire may charge to their natural gas transportation and/or storage customers. Those approved rates also impact the returns that Supply Corporation and Empire may earn on the assets that are dedicated to those operations. Pursuant to the petition of a customer or state commission, or on the FERC's own initiative, the FERC has the authority to investigate whether Supply Corporation's and Empire's rates are still "just and reasonable" as required by the NGA, and if not, to 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 currently projects that it may issue a Notice of Proposed Rulemaking by April 2013. 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.

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 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.

A case in Pennsylvania has created uncertainty as to the application of long-standing legal precedent to title disputes involving natural gas produced from the Marcellus Shale formation, potentially exposing the Company to litigation.

When acquiring interests in properties in Pennsylvania from which the Company produces natural gas, the Company has relied upon a body of law developed by Pennsylvania courts over the course of more than 125 years. A long-standing rule of construction under Pennsylvania law known as the "Dunham Rule" creates a presumption that a deed, lease or other instrument that conveys, or reserves, "minerals" does not convey, or reserve, interests in natural gas or oil absent clear and convincing evidence that the parties to the conveyance contract intended to include oil and natural gas within the word "minerals." A case in the intermediate appellate court in Pennsylvania (Butler v. Estate of Powers, Pa. Superior Ct., No. 1795 MDA 2010) creates uncertainty as to the application of the Dunham Rule in cases involving natural gas produced from the Marcellus Shale formation. Depending on the outcome of the ongoing litigation in Butler, the case could give rise to litigation as to whether, under the language of particular title documents and in consideration of the intent of the parties to particular conveyance contracts, rights to natural gas produced from the Marcellus Shale formation belong to the owner of the natural gas estate or the owner of the mineral estate. The Company believes that the Pennsylvania courts will ultimately confirm that the Dunham Rule applies to natural gas produced from the Marcellus Shale formation. If they were to hold otherwise, the Company could be involved in litigation to establish that the intent behind the conveyances to the Company of natural gas interests in Pennsylvania includes natural gas produced from the Marcellus Shale formation.

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.

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 have experienced such a change at the Canada/United States border at the Niagara River, where gas prices have increased relative to prices available at Leidy, Pennsylvania. This change in price differential has caused shippers to seek alternative lower priced gas supplies and, consequently, alternative transportation routes. Supply Corporation and Empire have seen transportation volumes decrease as a result of this situation, and in some cases, shippers have 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 have decreased, revenues and earnings in the Pipeline and Storage segment have decreased. Additional declines in this contracted transportation capacity could further adversely affect revenues, cash flows and results of operations. Supply Corporation and Empire are responding 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 by futures commission merchants. Under NYMEX 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, and other provisions related to derivatives have or will become effective as federal agencies (including the Commodity Futures Trading Commission (CFTC), various banking regulators and the SEC) adopt rules to implement the law. 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 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 capital and margin costs through higher 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-cleared swap that is available as a cleared swap may be greater.

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, 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 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 proposed regulations that would 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. If adopted, any such new state or federal legislation or regulation could lead to operational delays or restrictions, increased operating costs, additional regulatory burdens and increased risks of litigation for the Company's Exploration and Production segment.

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.

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 $4.7 billion at September 30, 2012. Approximately 48% 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 also comprises 48% 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 remaining net investment in property, plant and equipment consisted of the All Other and Corporate operations (4%). 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 $1.9 billion, or 65.0%, since 2007. 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, 2012. The net investment in its gas distribution network (including 14,845 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, 2012.

The Pipeline and Storage segment had a net investment of $1.1 billion in property, plant and equipment at September 30, 2012. Transmission pipeline represents 38% of this segment's total net investment and includes 2,384 miles of pipeline utilized to move large volumes of gas throughout its service area. Storage facilities represent 17% 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 422 miles of pipeline. Net investment in storage facilities includes $87.8 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 34 compressor stations with 121,782 installed compressor horsepower that represent 14% 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 $2.3 billion at September 30, 2012.

The Pipeline and Storage segments' facilities provided the capacity to meet Supply Corporation's 2012 peak day sendout, including transportation service, of 1,571 MMcf, which occurred on January 3, 2012. Withdrawals from storage of 680.3 MMcf provided approximately 43.3% 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 N — Supplementary Information for Oil and Gas Producing Activities. Note N sets forth proved developed and undeveloped reserve information for Seneca. The September 30, 2012, 2011 and 2010 reserves shown in Note N 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 nine 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 that determines the reserves. The Vice President of Reservoir Engineering reviews and approves all new reserve assignments and significant reserve revisions. Access to the Reserve database is restricted. Significant changes to the reserve report are reviewed by senior management on a quarterly basis. Periodically, the Company's internal audit department assesses the design of these controls and performs testing to determine the effectiveness of such controls.

All of the Company's reserve estimates are audited annually by Netherland, Sewell and Associates, Inc. (NSAI). Since 1961, NSAI has evaluated gas and oil properties and independently certified petroleum reserve quantities in the United States and internationally under the Texas Board of Professional Engineers Registration No. F-002699. The primary technical persons (employed by NSAI) that are responsible for leading the audit include a professional engineer registered with the State of Texas (with 14 years of experience in petroleum engineering and consulting at NSAI since 2004) and a professional geoscientist registered in the State of Texas (with 15 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, 2012 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 include 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 675 Bcf at September 30, 2011 to 988 Bcf at September 30, 2012. This increase is 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.

Seneca's proved developed and undeveloped natural gas reserves increased from 428 Bcf at September 30, 2010 to 675 Bcf at September 30, 2011. This increase was attributed primarily to extensions and discoveries of 249 Bcf, substantially all of which was in the Appalachian region, purchases of 45 Bcf in the Marcellus Shale in the Appalachian region, and positive revisions of previous estimates of 26 Bcf. This increase was partially offset by production of 51 Bcf and sales of minerals in place of 24 Bcf, primarily from the off-shore Gulf of Mexico sale. Seneca's proved developed and undeveloped oil reserves decreased from 45,239 Mbbl at September 30, 2010 to 43,345 Mbbl at September 30, 2011. Extensions and discoveries of 767 Mbbl and positive revisions of previous estimates of 1,616 Mbbl were exceeded by production of 2,860 Mbbl, primarily occurring in the West Coast region (2,628 Mbbl) and sales of minerals in place of 1,417 Mbbl, primarily from the off-shore Gulf of Mexico sale (979 Mbbl). On a Bcfe basis, Seneca's proved developed and undeveloped reserves increased from 700 Bcfe at September 30, 2010 to 935 Bcfe at September 30, 2011.

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 Company's proved undeveloped (PUD) reserves increased from 177 Bcfe at September 30, 2010 to 295 Bcfe at September 30, 2011. PUD reserves in the Marcellus Shale increased from 110 Bcf at September 30, 2010 to 253 Bcf at September 30, 2011. There was a material increase in PUD reserves at September 30, 2011 and 2010 as a result of Marcellus Shale reserve additions. The Company's total PUD reserves were 32% of total proved reserves at September 30, 2011, up from 25% of total proved reserves at September 30, 2010.

The increase in PUD reserves in 2012 of 115 Bcfe is 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 increase in PUD reserves in 2011 of 118 Bcfe was a result of 212 Bcfe in new PUD reserve additions (209 Bcfe from the Marcellus Shale), offset by 83 Bcfe in PUD conversions to proved developed reserves, 10 Bcfe from sales of minerals in place and 2 Bcfe in downward PUD revisions of previous estimates. The downward revisions were primarily from the removal of proved locations in the Upper Devonian play. These locations are unlikely to be developed in the 5-year timeframe due to the Company's focus on the Marcellus Shale and the better economic results there.

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. In 2013, the Company estimates that it will invest approximately $160 million to develop its PUD reserves. 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 represents 33% of the PUD reserves booked at September 30, 2011. The Company invested $146 million during the year ended September 30, 2011 to convert 83 Bcfe of September 30, 2010 PUD reserves to proved developed reserves. This represented 47% of the PUD reserves booked at September 30, 2010. The Company invested an additional $53 million during the year ended September 30, 2011 to develop the additional working interests in Covington area PUD wells that were acquired from EOG Resources during fiscal 2011.

At September 30, 2012, 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 or country level. All of the Company's proved reserves are in the United States. At the field level, only at the North Lost Hills Field in Kern County, California, does the Company have a material concentration of PUD reserves that have been on the books for more than five years. The Company has reduced the concentration of PUD reserves in this field from 44% of total field level proved reserves at September 30, 2007 to 16% of total field level proved reserves at September 30, 2012. The PUD reserves in this field represent less than 1% of the Company's proved reserves at the corporate level. The economics of this project remain strong and the steam-flood project here is performing well. Drilling of the remaining proved undeveloped locations in this field is scheduled over the next three years as steam generation capacity is increased and the steam-flood here matures.

At September 30, 2012, the Company's Exploration and Production segment had delivery commitments of 380 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.

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		
	2012	2011	2010
United States			
Appalachian Region			
Average Sales Price per Mcf of Gas	$ 2.71(3)	$ 4.37(3)	$ 4.93(3)
Average Sales Price per Barrel of Oil	$ 93.94	$86.58	$75.81
Average Sales Price per Mcf of Gas (after hedging)	$ 4.19	$ 5.24	$ 6.15
Average Sales Price per Barrel of Oil (after hedging)	$ 93.94	$86.58	$75.81
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 0.68(3)	$ 0.59(3)	$ 0.73(3)
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	172(3)	118(3)	45(3)
West Coast Region			
Average Sales Price per Mcf of Gas	$ 3.43	$ 4.56	$ 4.81
Average Sales Price per Barrel of Oil	$107.13	$96.45	$71.72(2)
Average Sales Price per Mcf of Gas (after hedging)	$ 5.70	$ 7.19	$ 7.02
Average Sales Price per Barrel of Oil (after hedging)	$ 90.84	$80.51	$74.88(2)
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 1.98	$ 2.06	$ 1.71(2)
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	56	53	54(2)
Gulf Coast Region			
Average Sales Price per Mcf of Gas	N/M	$ 5.02	$ 5.22
Average Sales Price per Barrel of Oil	N/M	$88.57	$76.57
Average Sales Price per Mcf of Gas (after hedging)	N/M	$ 5.50	$ 5.51
Average Sales Price per Barrel of Oil (after hedging)	N/M	$88.57	$77.18
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	N/M	$ 1.59	$ 1.15
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	N/M	25(1)	37
Total Company			
Average Sales Price per Mcf of Gas	$ 2.75	$ 4.43	$ 5.01
Average Sales Price per Barrel of Oil	$106.97	$95.78	$72.54
Average Sales Price per Mcf of Gas (after hedging)	$ 4.27	$ 5.39	$ 6.04
Average Sales Price per Barrel of Oil (after hedging)	$ 90.88	$81.13	$75.25
Average Production (Lifting) Cost per Mcf Equivalent of Gas and Oil Produced	$ 1.00	$ 1.08	$ 1.24
Average Production per Day (in MMcf Equivalent of Gas and Oil Produced)	228	185	136

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

(2) The Midway Sunset North fields (which exceeded 15% of total reserves at 9/30/2010) contributed 25 MMcfe of production per day, at an average sales price (per bbl) of $69.68 ($75.75 after hedging) for 2010. Lifting cost (per Mcfe) was $1.90 for 2010.

(3) The Marcellus Shale fields (which exceed 15% of total reserves at 9/30/2012, 9/30/2011 and 9/30/2010) contributed 152 MMcfe, 97 MMcfe and 20 MMcfe of daily production in 2012, 2011 and 2010, respectively. The average sales price (per Mcfe) was $2.67 ($3.66 after hedging) in 2012, $4.34 ($4.68

after hedging) in 2011 and $4.56 in 2010. The Company did not hedge Marcellus Shale production during 2010. The average lifting costs (per Mcfe) were $0.61 in 2012, $0.48 in 2011 and $0.55 in 2010.

Productive Wells

At September 30, 2012	Appalachian Region		West Coast Region		Total Company	
	Gas	Oil	Gas	Oil	Gas	Oil
Productive Wells — Gross	3,018	2	—	1,649	3,018	1,651
Productive Wells — Net	2,961	2	—	1,609	2,961	1,611

Developed and Undeveloped Acreage

At September 30, 2012	Appalachian Region	West Coast Region	Total Company
Developed Acreage			
— Gross	536,494	14,370	550,864
— Net	526,812	11,479	538,291
Undeveloped Acreage			
— Gross	401,424	28,171	429,595
— Net	382,998	9,911	392,909
Total Developed and Undeveloped Acreage			
— Gross	937,918	42,541	980,459
— Net	909,810	21,390	931,200

As of September 30, 2012, the aggregate amount of gross undeveloped acreage expiring in the next three years and thereafter are as follows: 10,532 acres in 2013 (5,516 net acres), 11,322 acres in 2014 (4,907 net acres), 22,934 acres in 2015 (15,646 net acres), and 60,039 acres thereafter (54,832 net acres). The remaining 324,768 gross acres (312,008 net acres) represent non-expiring oil and gas rights owned by the Company.

Drilling Activity

For the Year Ended September 30	Productive			Dry		
	2012	2011	2010	2012	2011	2010
United States						
Appalachian Region						
Net Wells Completed						
— Exploratory	7.00	13.00	33.00	—	—	2.00
— Development	50.50	48.76	131.55	2.00	—	3.00
West Coast Region						
Net Wells Completed						
— Exploratory	—	0.25	—	—	—	—
— Development	56.99	43.31	41.72	—	—	—
Gulf Coast Region						
Net Wells Completed						
— Exploratory	—	—	0.29	—	—	—
— Development	—	0.40	—	—	—	—
Total Company						
Net Wells Completed						
— Exploratory	7.00	13.25	33.29	—	—	2.00
— Development	107.49	92.47	173.27	2.00	—	3.00

Present Activities

At September 30, 2012	Appalachian Region	West Coast Region	Total Company
Wells in Process of Drilling(1)			
— Gross	83.00	1.00	84.00
— Net	60.50	0.13	60.63

(1) Includes wells awaiting completion.

Item 3 ***Legal Proceedings***

On November 14, 2012, the PaDEP sent a draft Consent Assessment of Civil Penalty ("Draft Consent") 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 in no way material to the Company but exceeds a $100,000 threshold set forth in SEC regulations for disclosure of certain environmental proceedings. 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. As of September 30, 2012, the Company has spent approximately $80.1 million in constructing this project.

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.

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 M — Market for Common Stock and Related Shareholder Matters (unaudited).

On July 2, 2012, the Company issued a total of 4,050 unregistered shares of Company common stock to the nine non-employee directors of the Company then serving on the Board of Directors of the Company, 450 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, 2012. These transactions were exempt from registration under Section 4(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, 2012	7,408	$49.56	—	6,971,019
Aug. 1-31, 2012	6,897	$50.77	—	6,971,019
Sept. 1-30, 2012	11,226	$52.86	—	6,971,019
Total	25,531	$51.34	—	6,971,019

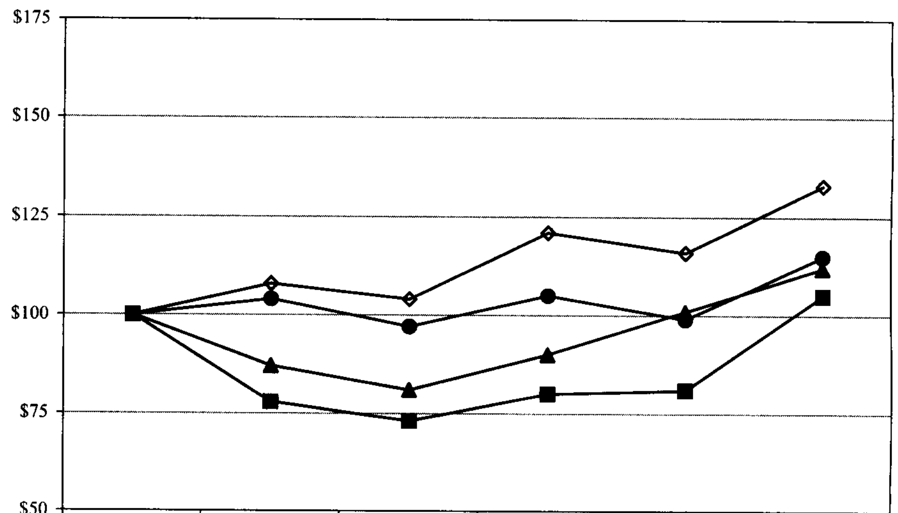
(a) Represents (i) shares of common stock of the Company purchased on the open market with Company "matching contributions" for the accounts of participants in the Company's 401(k) plans, and (ii) shares of common stock of the Company tendered to the Company by holders of stock options, SARs or shares of restricted stock for the payment of option exercise prices or applicable withholding taxes. During the quarter ended September 30, 2012, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program. Of the 25,531 shares purchased other than through a publicly announced share repurchase program, 21,471 were purchased for the Company's 401(k) plans and 4,060 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.

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, 2007 through September 30, 2012. The graph assumes that the value of the investment in the Company's common stock and in each index was $100 on September 30, 2007 and that all dividends were reinvested.

Comparison of Five-Year Cumulative Total Returns
Fiscal Years 2008-2012



	2007	2008	2009	2010	2011	2012
National Fuel	$100	$108	$104	$121	$116	$133
S&P 500 Index	$100	$78	$73	$80	$81	$105
PHLX Utility Sector Index (UTY)	$100	$87	$81	$90	$101	$112
SIG Oil Exploration & Production Index (EPX)	$100	$104	$97	$105	$99	$115

National Fuel — S&P 500 Index — PHLX Utility Sector Index (UTY) — SIG Oil Exploration & Production Index (EPX)

Source: Bloomberg

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

Item 6 ***Selected Financial Data***

	Year Ended September 30				
	2012	2011	2010	2009	2008
	(Thousands, except per share amounts and number of registered shareholders)				
Summary of Operations					
Operating Revenues	$1,626,853	$1,778,842	$1,760,503	$2,051,543	$2,396,837
Operating Expenses:					
Purchased Gas	415,589	628,732	658,432	997,216	1,238,405
Operation and Maintenance	401,397	400,519	394,569	401,200	429,394
Property, Franchise and Other Taxes	90,288	81,902	75,852	72,102	75,525
Depreciation, Depletion and Amortization	271,530	226,527	191,199	170,620	169,846
Impairment of Oil and Gas Producing Properties	—	—	—	182,811	—
	1,178,804	1,337,680	1,320,052	1,823,949	1,913,170
Operating Income	448,049	441,162	440,451	227,594	483,667
Other Income (Expense):					
Gain on Sale of Unconsolidated Subsidiaries	—	50,879	—	—	—
Impairment of Investment in Partnership	—	—	—	(1,804)	—
Other Income	5,133	5,947	6,126	11,566	13,467
Interest Income	3,689	2,916	3,729	5,776	10,815
Interest Expense on Long-Term Debt	(82,002)	(73,567)	(87,190)	(79,419)	(70,099)
Other Interest Expense	(4,238)	(4,554)	(6,756)	(7,370)	(3,271)
Income from Continuing Operations Before Income Taxes	370,631	422,783	356,360	156,343	434,579
Income Tax Expense	150,554	164,381	137,227	52,859	167,672
Income from Continuing Operations	220,077	258,402	219,133	103,484	266,907
Discontinued Operations:					
Income (Loss) from Operations, Net of Tax	—	—	470	(2,776)	1,821
Gain on Disposal, Net of Tax	—	—	6,310	—	—
Income (Loss) from Discontinued Operations, Net of Tax	—	—	6,780	(2,776)	1,821
Net Income Available for Common Stock	$ 220,077	$ 258,402	$ 225,913	$ 100,708	$ 268,728
Per Common Share Data					
Basic Earnings from Continuing Operations per Common Share	$ 2.65	$ 3.13	$ 2.70	$ 1.29	$ 3.25
Diluted Earnings from Continuing Operations per Common Share	$ 2.63	$ 3.09	$ 2.65	$ 1.28	$ 3.16
Basic Earnings per Common Share(1)	$ 2.65	$ 3.13	$ 2.78	$ 1.26	$ 3.27
Diluted Earnings per Common Share(1)	$ 2.63	$ 3.09	$ 2.73	$ 1.25	$ 3.18
Dividends Declared	$ 1.44	$ 1.40	$ 1.36	$ 1.32	$ 1.27
Dividends Paid	$ 1.43	$ 1.39	$ 1.35	$ 1.31	$ 1.26
Dividend Rate at Year-End	$ 1.46	$ 1.42	$ 1.38	$ 1.34	$ 1.30
At September 30:					
Number of Registered Shareholders	13,800	14,355	15,549	16,098	16,544

	Year Ended September 30				
	2012	2011	2010	2009	2008
	(Thousands, except per share amounts and number of registered shareholders)				
Net Property, Plant and Equipment					
Utility	$1,217,431	$1,189,030	$1,165,240	$1,144,002	$1,125,859
Pipeline and Storage	1,069,070	954,554	858,231	839,424	826,528
Exploration and Production	2,273,030	1,753,194	1,338,956	1,041,846	1,095,960
Energy Marketing	1,530	850	436	71	98
All Other(2)	173,514	97,228	81,103	101,104	98,338
Corporate	5,228	5,668	6,263	6,915	7,317
Total Net Plant	$4,739,803	$4,000,524	$3,450,229	$3,133,362	$3,154,100
Total Assets	$5,935,142	$5,221,084	$5,047,054	$4,769,129	$4,130,187
Capitalization					
Comprehensive Shareholders' Equity	$1,960,095	$1,891,885	$1,745,971	$1,589,236	$1,603,599
Long-Term Debt, Net of Current Portion	1,149,000	899,000	1,049,000	1,249,000	999,000
Total Capitalization	$3,109,095	$2,790,885	$2,794,971	$2,838,236	$2,602,599

(1) Includes discontinued operations.

(2) Includes net plant of landfill gas discontinued operations as follows: $0 for 2012, 2011 and 2010, $9,296 for 2009 and $11,870 for 2008.

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 four business segments. 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) 2012 and projected 2013 funding for the Company's pension and other post-retirement benefits; (b) disclosures and tables concerning market risk sensitive instruments; (c) rate and regulatory matters in the Company's New York, Pennsylvania and FERC regulated jurisdictions; (d) environmental matters; and (e) new authoritative accounting and financial reporting guidance.

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

For the year ended September 30, 2012 compared to the year ended September 30, 2011, the Company experienced a decrease in earnings of $38.3 million. The earnings decrease is primarily due to the recognition of a gain on the sale of unconsolidated subsidiaries of $50.9 million ($31.4 million after tax) during the quarter ended March 31, 2011 in the All Other category that did not recur during the year ended September 30, 2012. In February 2011, the Company sold its 50% equity method investments in Seneca Energy and Model City for $59.4 million. Seneca Energy and Model City generate and sell electricity using methane gas obtained from landfills owned by outside parties. The sale was 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. Lower earnings in the Exploration and Production segment, Utility segment and Energy Marketing segment also contributed to the decrease in earnings, partly offset by higher earnings in the Pipeline and Storage segment. 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 607 Bcf at September 30, 2011 to 925 Bcf at September 30, 2012. The Company has spent significant amounts of capital in this region related to the development of such reserves. For the year ended September 30, 2012, the Company's Exploration and Production segment had capital expenditures of $630.9 million in the Appalachian region, of which $567.9 million was spent towards the development of the Marcellus Shale. However, while the Company remains focused on the development of the Marcellus Shale, the current low natural gas price environment has caused the Company to reduce its capital spending plans for fiscal 2013. The Company's fiscal 2013 estimated capital expenditures in the Appalachian region are expected to be approximately $405.3 million. Despite the reduction in capital expenditures, forecasted production in the Appalachian region for fiscal 2013 is expected to be in the range of 75 to 85 Bcfe, up from actual production of 63 Bcfe in fiscal 2012.

While the Company's development of its Marcellus Shale acreage in the Exploration and Production segment has slowed, the Company's Pipeline and Storage segment continues to build pipeline gathering and transmission facilities to connect Marcellus Shale production with existing pipelines in the region and is pursuing the development of additional pipeline and storage capacity in order to meet anticipated demand for the large amount of Marcellus Shale production expected to come on-line in the months and years to come. One such project, Empire's Tioga County Extension Project, was placed in service in November 2011. Supply Corporation's Northern Access expansion project is also considered significant. Just like the Tioga County Extension Project, the Northern Access expansion project is designed to receive natural gas produced from the Marcellus Shale and transport it to Canada and the Northeast United States to meet growing demand in those areas. Initial service through the Northern Access expansion project began on November 1, 2012, with full service expected by the end of December 2012. These projects, which are further discussed in the Investing Cash Flow section that follows, have or will involve significant capital expenditures.

From a capital resources perspective, the Company has largely been able to meet its capital expenditure needs for all of the above projects by using cash from operations as well as short-term debt. In addition, the Company's December 2011 issuance of $500.0 million of 4.90% notes due in December 2021 enhanced its liquidity position to meet these needs. On January 6, 2012, the Company replaced its $300.0 million committed credit facility with an Amended and Restated Credit Agreement totaling $750.0 million that extends to January 6, 2017. Going forward, the Company plans to continue its use of short-term debt and expects to issue long-term debt in fiscal 2013 to help meet its capital expenditure needs as well as to replace long-term debt that matures in March 2013.

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.

The Company believes that determining the amount of the Company's proved reserves is a critical accounting estimate. 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, 2012, the ceiling exceeded the book value of the Company's oil and gas properties by approximately $55.3 million. The 12-month average of the first day of the month price for crude oil for each month during 2012, based on posted Midway Sunset prices, was $105.09 per Bbl. The 12-month average of the first day of the month price for natural gas for each month during 2012, based on the quoted Henry Hub spot price for natural gas, was $2.83 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 2012.) If natural gas average prices used in the ceiling test calculation at September 30, 2012 had been $1 per MMBtu lower, the book value of the Company's oil and gas properties would have exceeded the ceiling by approximately $173.9 million, which would have resulted in an impairment charge. If crude oil average prices used in the ceiling test calculation at September 30, 2012 had been $5 per Bbl lower, the ceiling would have exceeded the book value of the Company's oil and gas properties by approximately $10.3 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, 2012 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 $221.3 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, in its Exploration and Production segment, Energy Marketing segment, and Pipeline and Storage segment, uses or has used 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 are categorized as price swap agreements and futures contracts. In accordance with the authoritative guidance for derivative instruments and hedging activities, the Company accounted for these instruments as effective cash flow hedges or fair value hedges. Gains or losses associated with the derivative financial instruments are matched with gains or losses resulting from the underlying physical transaction that is being hedged. To the extent that the derivative financial instruments would ever be deemed to be ineffective based on the effectiveness testing, mark-to-market gains or losses from the derivative financial instruments would be recognized in the income statement without regard to an underlying physical transaction.

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 a yield curve 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. 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 4.50% in 2011 to 3.50% in 2012. The change in the discount rate from 2011 to 2012 increased the Retirement Plan projected benefit obligation by $118.8 million and the accumulated post-retirement benefit obligation by $65.6 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 2012, the actual return on plan assets exceeded the expected return, which improved the funded status of the Retirement Plan

($51.3 million) as well as the VEBA trusts and 401(h) accounts ($34.6 million). The actual versus expected benefit payments for 2012 caused a decrease of $2.4 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.

RESULTS OF OPERATIONS

EARNINGS

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 a lower loss in the Corporate category partly offset these decreases. 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 2012 and 2011:

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."

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.

2011 Compared with 2010

The Company's earnings were $258.4 million in 2011 compared with earnings of $225.9 million in 2010. The Company had earnings from discontinued operations of $6.8 million in 2010 but did not have any earnings from discontinued operations in 2011. The Company sold its landfill gas operations in the states of Ohio, Michigan, Kentucky, Missouri, Maryland and Indiana in September 2010. Accordingly, all financial results for those operations, which were part of the All Other category, have been presented as discontinued operations. The Company's earnings from continuing operations were $258.4 million in 2011 and $219.1 million in 2010. The increase in earnings from continuing operations of $39.3 million was primarily the result of higher earnings in the Exploration and Production segment and the All Other category. The increase in the All Other category was due to the gain on sale of the Company's 50% equity method investments in Seneca Energy and Model City. The Utility segment also contributed to the increase in earnings. Lower earnings in the Pipeline and Storage segment and a higher loss in the Corporate category slightly offset these increases. Earnings from continuing operations and discontinued operations were also impacted by the following event in 2010:

2010 Event

- A $6.3 million gain on the sale of the Company's landfill gas operations, which was completed in September 2010. This amount is included in earnings from discontinued operations.

Earnings (Loss) by Segment

	Year Ended September 30		
	2012	2011	2010
		(Thousands)	
Utility	$ 58,590	$ 63,228	$ 62,473
Pipeline and Storage	60,527	31,515	36,703
Exploration and Production	96,498	124,189	112,531
Energy Marketing	4,169	8,801	8,816
Total Reported Segments	219,784	227,733	220,523
All Other	6,868	38,502	3,396
Corporate	(6,575)	(7,833)	(4,786)
Total Earnings from Continuing Operations	220,077	258,402	219,133
Earnings from Discontinued Operations	—	—	6,780
Total Consolidated	$220,077	$258,402	$225,913

UTILITY

Revenues

Utility Operating Revenues

	Year Ended September 30		
	2012	2011	2010
		(Thousands)	
Retail Revenues:			
Residential	$493,354	$603,838	$583,443
Commercial	61,314	80,811	81,110
Industrial	5,359	5,849	5,697
	560,027	690,498	670,250
Off-System Sales	27,010	33,968	29,135
Transportation	122,316	123,729	109,675
Other	9,769	4,300	10,730
	$719,122	$852,495	$819,790

Utility Throughput — million cubic feet (MMcf)

	Year Ended September 30		
	2012	2011	2010
Retail Sales:			
Residential	47,036	57,466	54,012
Commercial	6,682	8,517	8,203
Industrial	837	723	646
	54,555	66,706	62,861
Off-System Sales	9,544	7,151	5,899
Transportation	61,027	66,273	60,105
	125,126	140,130	128,865

Degree Days

Year Ended September 30		Normal	Actual	Percent (Warmer) Colder Than Normal	Prior Year
2012(1):	Buffalo	6,729	5,296	(21.3)%	(21.6)%
	Erie	6,277	4,999	(20.4)%	(21.4)%
2011(2):	Buffalo	6,692	6,751	0.9%	7.3%
	Erie	6,243	6,359	1.9%	6.9%
2010(3):	Buffalo	6,692	6,292	(6.0)%	(6.1)%
	Erie	6,243	5,947	(4.7)%	(3.7)%

(1) 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.

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

(3) Percents compare actual 2010 degree days to normal degree days and actual 2010 degree days to actual 2009 degree days.

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 volumes (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 has 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 is a corresponding reduction in the ability to conduct off-system sales during that period. Distribution Corporation intends to meet its gas purchase needs through the spot market during the April through October time frame. It will continue to maintain contractual commitments to purchase gas from the southwest region of the United States during the November through March time 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.

2011 Compared with 2010

Operating revenues for the Utility segment increased $32.7 million in 2011 compared with 2010. This increase largely resulted from a $20.2 million increase in retail gas sales revenues, a $14.1 million increase in transportation revenues, and a $4.8 million increase in off-system sales revenue. These were partially offset by a $6.4 million decrease in other operating revenues.

The increase in retail gas sales revenues of $20.2 million was largely a function of higher volumes (3.8 Bcf) due to colder weather and higher customer usage per account. The increase in volumes resulted in the recovery of a larger amount of gas costs, despite a decline in the Utility segment's average cost of purchased gas. 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 increase in transportation revenues of $14.1 million was primarily due to a 6.2 Bcf increase in transportation throughput, largely the result of colder weather and the migration of customers from retail sales to transportation service. The increase in off-system sales revenues was largely due to an increase in off-system sales volume, which have minimal impact to margins. The $6.4 million decrease in other operating revenues was largely attributable to an adjustment to the carrying value of certain regulatory asset accounts to a level the Company believes will ultimately be recovered in the rate-setting process.

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 volumes, the price of gas purchased and the operation of purchased gas adjustment clauses. Distribution Corporation recorded $340.3 million, $460.1 million and $428.4 million of Purchased Gas expense during 2012, 2011 and 2010, 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. Changes in wellhead prices have a direct impact on the cost of purchased gas. Distribution Corporation's average cost of purchased gas, including the cost of transportation and storage, was $5.09 per Mcf in 2012, a decrease of 21% from the average cost of $6.41 per Mcf in 2011. The average cost of purchased gas in 2011 was 10% lower than the average cost of $7.13 per Mcf in 2010. Additional discussion of the Utility segment's gas purchases appears under the heading "Sources and Availability of Raw Materials" in Item 1.

Earnings

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 is 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, is largely due to lower personnel costs and lower property taxes (as a result of a decrease in assessed property values).

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 2012, the WNC preserved earnings of approximately $5.9 million, as the weather was warmer than normal. For 2011, the WNC reduced earnings by approximately $1.0 million, as the weather was colder than normal.

2011 Compared with 2010

The Utility segment's earnings in 2011 were $63.2 million, an increase of $0.7 million when compared with earnings of $62.5 million in 2010. The increase in earnings is largely attributable to colder weather ($2.4 million) and higher usage per account ($1.9 million) in Pennsylvania. In addition, earnings were positively impacted by lower interest expense on deferred gas costs ($1.0 million) and lower operating expenses ($1.6 million) due to decreased bad debt expense and personnel costs partially offset by higher pension expense. These increases were partially offset by various regulatory adjustments ($3.7 million), primarily due to an adjustment to the carrying value of certain regulatory asset accounts to a level the Company believes will ultimately be recovered in the rate-setting process, an increase in other taxes ($0.9 million), higher income tax expense ($0.7 million) and higher depreciation expense ($0.3 million).

For 2010, the WNC preserved earnings of approximately $1.3 million, as the weather was warmer than normal.

PIPELINE AND STORAGE

Revenues

Pipeline and Storage Operating Revenues

	Year Ended September 30		
	2012	2011	2010
		(Thousands)	
Firm Transportation	$164,652	$134,652	$139,324
Interruptible Transportation	1,431	1,341	1,863
	166,083	135,993	141,187
Firm Storage Service	67,929	66,712	66,593
Interruptible Storage Service	7	19	78
	67,936	66,731	66,671
Other	25,256	12,384	11,025
	$259,275	$215,108	$218,883

Pipeline and Storage Throughput — (MMcf)

	Year Ended September 30		
	2012	2011	2010
Firm Transportation	369,477	317,917	296,907
Interruptible Transportation	1,662	2,037	4,459
	371,139	319,954	301,366

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 and 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. 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. The rate case and the settlement are discussed further in the Rate and Regulatory Matters section and in Item 8 at Note C – Regulatory Matters. 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 volumes 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 volumes 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 volumes for power generation on Empire's system during the spring and summer of fiscal 2012 more than offset lower transportation volumes experienced by both Supply Corporation and Empire during the fall and winter of fiscal 2012 due to warmer weather. 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.

2011 Compared with 2010

Operating revenues for the Pipeline and Storage segment decreased $3.8 million in 2011 as compared with 2010. The decrease was primarily due to a decrease in transportation revenues of $5.2 million. The decrease in transportation revenues was primarily the result of a reduction in the level of contracts entered into by shippers year over year as shippers utilized lower priced pipeline transportation routes. Shippers continued to seek alternative lower priced gas supply (and in some cases, did not renew short-term transportation contracts) because of the relatively higher price of natural gas supplies available at the United States/Canadian border at the Niagara River near Buffalo, New York compared to the lower pricing for supplies available at Leidy, Pennsylvania. The decrease was partially offset by an increase in efficiency gas revenues of $1.0 million (reported as a part of other revenue in the table above) due to higher efficiency gas volumes partially offset by lower gas prices. Also offsetting the decrease in revenues was an increase in cashout revenues of $0.3 million (reported as a part of other revenue in the table above). Cashout revenues are completely offset by purchased gas expense and as a result have no impact on earnings.

Transportation volume increased by 18.6 Bcf in 2011 as compared with 2010. While transportation volume increased largely due to colder weather, there was little impact on revenues due to the straight fixed-variable rate design.

Earnings

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 is 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), as 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 is 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.

2011 Compared with 2010

The Pipeline and Storage segment's earnings in 2011 were $31.5 million, a decrease of $5.2 million when compared with earnings of $36.7 million in 2010. The decrease in earnings is primarily due to the earnings impact of higher operating expenses ($3.2 million), lower transportation revenues of $3.4 million, as discussed above, higher depreciation expense ($0.9 million) and higher property taxes ($0.3 million). The increase in operating expenses can be attributed primarily to higher pension expense ($1.4 million), higher compressor maintenance costs ($0.7 million), higher personnel costs ($0.6 million) and the write-off of expired and unused storage rights ($0.6 million). The increase in property taxes was primarily a result of a higher tax base due to capital additions combined with higher Pennsylvania public utility realty taxes. The increase in depreciation expense was primarily the result of a revision during fiscal 2011 to correct accumulated depreciation as well as additional projects that were placed in service during 2011. These earnings decreases were partially offset by an increase in the allowance for funds used during construction (equity component) of $2.0 million primarily due to construction commencing during 2011 on Supply Corporation's Line N Expansion Project and Lamont Phase II Project and Empire's Tioga County Extension Project and by the earnings impact associated with higher efficiency gas revenues ($0.7 million), as discussed above.

EXPLORATION AND PRODUCTION

Revenues

Exploration and Production Operating Revenues

	Year Ended September 30		
	2012	2011	2010
		(Thousands)	
Gas (after Hedging)	$282,494	$272,057	$183,327
Oil (after Hedging)	260,844	232,052	242,303
Gas Processing Plant	24,826	28,711	29,369
Other	212	513	820
Intrasegment Elimination(1)	(10,196)	(14,298)	(17,791)
Operating Revenues	$558,180	$519,035	$438,028

(1) Represents the elimination of certain West Coast gas production revenue included in "Gas (after Hedging)" in the table above that is sold to the gas processing plant shown in the table above. An elimination for the same dollar amount was made to reduce the gas processing plant's Purchased Gas expense.

Production

	Year Ended September 30		
	2012	2011	2010
Gas Production *(MMcf)*			
Appalachia	62,663	42,979	16,222
West Coast	3,468	3,447	3,819
Gulf Coast	—	4,041	10,304
Total Production	66,131	50,467	30,345
Oil Production *(Mbbl)*			
Appalachia	36	45	49
West Coast	2,834	2,628	2,669
Gulf Coast	—	187	502
Total Production	2,870	2,860	3,220

Average Prices

	Year Ended September 30		
	2012	2011	2010
Average Gas Price/Mcf			
Appalachia	$ 2.71	$ 4.37	$ 4.93
West Coast	$ 3.43	$ 4.56	$ 4.81
Gulf Coast	N/M	$ 5.02	$ 5.22
Weighted Average	$ 2.75	$ 4.43	$ 5.01
Weighted Average After Hedging(1)	$ 4.27	$ 5.39	$ 6.04
Average Oil Price/Barrel (bbl)			
Appalachia	$ 93.94	$86.58	$75.81
West Coast	$107.13	$96.45	$71.72
Gulf Coast	N/M	$88.57	$76.57
Weighted Average	$106.97	$95.78	$72.54
Weighted Average After Hedging(1)	$ 90.88	$81.13	$75.25

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

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 $10.4 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 $1.12 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 segment's off-shore oil production as a result of the aforementioned sale.

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.

2011 Compared with 2010

Operating revenues for the Exploration and Production segment increased $81.0 million in 2011 as compared with 2010. Gas production revenue after hedging increased $88.7 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 additional wells within the Marcellus Shale formation, primarily in Tioga County, Pennsylvania, which came on line in 2011. 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 $0.65 per Mcf decrease in the weighted average price of gas after hedging. Oil production revenue after hedging decreased $10.3 million due to a decrease in production as a result of the aforementioned sale of Gulf Coast off-shore properties. This decrease in oil production revenue was partially offset by an increase in the weighted average price of oil after hedging ($5.88 per Bbl). In addition, there was a $2.8 million increase in gas processing plant revenues (net of eliminations) primarily due to the lower cost of West Coast residual and liquids production in 2011 versus 2010.

Earnings

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 ($47.7 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 lease operating expenses ($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 is 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 $68.9 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 is largely due to higher money market investment balances.

2011 Compared with 2010

The Exploration and Production segment's earnings for 2011 were $124.2 million, compared with earnings of $112.5 million for 2010, an increase of $11.7 million. Higher natural gas production and higher crude oil prices increased earnings by $79.0 million and $10.9 million, respectively. Higher processing plant revenues ($1.8 million) further contributed to an increase in earnings. Lower interest expense ($8.4 million) due to a lower average amount of debt further contributed to an increase in earnings. Lower natural gas prices ($21.3 million) and lower crude oil production ($17.6 million) partially offset the increase in earnings. In addition, earnings were further reduced by higher depletion expense ($26.4 million), higher general, administrative and other operating expenses ($11.4 million), higher lease operating expenses ($7.7 million), higher income tax expense ($2.5 million), and higher property and other taxes ($1.0 million). The increase in depletion expense is primarily due to an increase in production and depletable base (largely due to increased capital spending in the Appalachian region, specifically related to the development of Marcellus Shale properties). The increase in lease operating expenses is largely attributable to a higher number of producing properties in Appalachia. Higher personnel costs are largely responsible for the increase in general, administrative and other operating expenses. Higher property and other taxes are attributable to a revision of the California property tax liability, which was partially offset by a decrease in property and other taxes as a result of the sale of the Gulf Coast's off-shore properties in April 2011. The increase in income tax expense is attributable to higher state income taxes coupled with the loss of a domestic production activities deduction that occurred during the quarter ended September 30, 2010 and its impact on the effective tax rate during fiscal 2011. The decrease in interest and other income is largely attributable to lower cash investment balances in 2011 as compared to 2010.

ENERGY MARKETING

Revenues

Energy Marketing Operating Revenues

	Year Ended September 30		
	2012	2011	2010
		(Thousands)	
Natural Gas (after Hedging)	$187,969	$284,916	$344,077
Other	35	50	725
	$188,004	$284,966	$344,802

Energy Marketing Volume

	Year Ended September 30		
	2012	2011	2010
Natural Gas — (MMcf)	45,756	52,893	58,299

2012 Compared with 2011

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

2011 Compared with 2010

Operating revenues for the Energy Marketing segment decreased $59.8 million in 2011 as compared with 2010. The decrease primarily reflects a decline in gas sales revenue due largely to a decrease in volume sold as well as a lower average price of natural gas. The decrease in volume is largely attributable to the non-recurrence of sales transactions undertaken at the Niagara pipeline delivery point to offset certain basis risks that the Energy Marketing segment was exposed to under certain fixed basis commodity purchase contracts for Appalachian production. The decrease in volume also reflects a decrease in volume sold to low-margin wholesale customers. Such transactions had the effect of increasing revenue and volume sold with minimal impact to earnings. The decrease in volume sold to wholesale customers was partially offset by an increase in volume sold to retail customers.

Earnings

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.

2011 Compared with 2010

The Energy Marketing segment's earnings were $8.8 million in both 2011 and 2010. A decrease in margin of $0.3 million was offset by the positive impact of lower income tax expense ($0.2 million) and lower operating costs ($0.1 million). The decrease in margin was due to a lower benefit that the Energy Marketing segment derived from its contracts for storage capacity and the non-recurrence of proceeds received in 2010 as a member of a class of claimants in a class action litigation settlement, offset somewhat by higher volume sold to retail customers.

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), Midstream Corporation and corporate operations. Seneca's Northeast Division markets timber from its New York and Pennsylvania land holdings. In September 2010, the Company sold its sawmill in Marienville, Pennsylvania along with the mill's inventory, stumpage tracts and certain land and timber acreage for approximately $15.8 million. The Company recognized a gain of approximately $0.4 million from this sale ($0.2 million after tax). The Company continues to maintain a forestry operation, but no longer processes lumber products. Midstream Corporation is a Pennsylvania corporation formed to build, own and operate natural gas processing and pipeline gathering facilities in the Appalachian region. 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. In September 2010, the Company sold its landfill gas operations in the states of Ohio, Michigan, Kentucky, Missouri, Maryland and Indiana for $38.0 million, recognizing a gain of $10.3 million ($6.3 million after tax). The Company's landfill gas operations were maintained under the Company's wholly owned subsidiary, Horizon LFG, which owned and operated these short distance landfill gas pipeline companies. These operations are presented in the Company's financial statements as discontinued operations. Refer to Item 8 at Note J — Discontinued Operations for further details.

Earnings

2012 Compared with 2011

All Other and Corporate operations had earnings of $0.3 million in 2012, a decrease of $30.4 million compared with earnings of $30.7 million in 2011. The decrease in earnings is 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, higher income tax expense of $2.6 million (largely due to the impact of the tax sharing agreement with affiliated companies), higher depreciation expense of $0.8 million (due to an increase in Midstream Corporation's gathering plant balances) and lower income from unconsolidated subsidiaries of $0.4 million further decreased earnings. Lower income from unconsolidated subsidiaries was largely the result of the impairment of ESNE (discussed above). The factors contributing to the overall decrease in earnings were partially offset by higher gathering and processing revenues of $4.0 million, lower property, franchise and other taxes of $0.6 million (due to lower property taxes as a result of a decrease in assessed property values), and higher margins of $0.3 million (due to an increase in revenues from the sale of standing timber). The increase in gathering and processing revenues are due to Midstream Corporation's increase in gathering operations for Marcellus Shale gas in the Pennsylvania counties of Tioga and Lycoming.

2011 Compared with 2010

All Other and Corporate operations had income from continuing operations of $30.7 million in 2011 compared with a loss from continuing operations of $1.4 million in 2010. The overall increase in earnings from continuing operations is due to the gain on the sale of Horizon Power's investments in Seneca Energy and Model City of $31.4 million, lower interest expense of $8.4 million (primarily the result of lower borrowings at a lower interest rate due to the repayment of $200 million of 7.5% notes that matured in November 2010), higher gathering and processing revenues of $5.1 million (due to an increase in Midstream Corporation's gathering and processing revenues) and lower depreciation and depletion expense of $4.6 million (due to a decrease in timber harvested as a result of the sale of the Company's timber harvesting and milling operations in September 2010). Lower income tax expense ($0.8 million) further contributed to the earnings increase. The factors contributing to the overall increase in earnings were partially offset by lower interest income of $8.1 million (due to lower interest collected from the Company's Exploration and Production segment as a result of the aforementioned November 2010 debt repayment), lower margins of $6.7 million (due to a decrease in timber harvested as a result of the sale of the Company's timber harvesting and milling operations in September 2010), higher property, franchise and other taxes of $1.4 million (due to an increase in capital stock expense recorded during the year ended September 30, 2011 related to fiscal year 2010) and higher operating expenses of $0.9 million (mostly due to an increase in Midstream Corporation's operating activities). Additionally, the Company recorded a loss from unconsolidated subsidiaries of $0.5 million during the year ended September 30, 2011 compared to income of $1.6 million during the year ended September 30, 2010. The change in income (loss) from unconsolidated subsidiaries reflects the sale of Seneca Energy and Model City combined with the dormancy of ESNE.

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 $8.4 million in 2012 as compared to 2011. This increase is 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 by $1.5 million in comparison to the prior year.

Interest on long-term debt decreased $13.6 million in 2011 as compared to 2010. This decrease is primarily the result of a lower average amount of long-term debt outstanding and slightly lower average interest rates. The Company repaid $200 million of 7.5% notes that matured in November 2010. In addition, there was an increase in capitalized interest associated with increased Exploration and Production segment capital expenditures in the Appalachian region, which decreased interest expense by $0.5 million 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		
	2012	2011	2010
		(Millions)	
Provided by Operating Activities	$ 660.8	$ 660.5	$ 447.0
Capital Expenditures	(1,036.8)	(820.8)	(443.1)
Net Proceeds from Sale of Timber Mill and Related Assets	—	—	15.8
Net Proceeds from Sale of Landfill Gas Pipeline Assets	—	—	38.0
Net Proceeds from Sale of Unconsolidated Subsidiaries	—	59.4	—
Net Proceeds from Sale of Oil and Gas Producing Properties	—	63.5	—
Other Investing Activities	0.5	(2.9)	(0.3)
Reduction of Long-Term Debt	(150.0)	(200.0)	—
Change in Notes Payable to Banks and Commercial Paper	131.0	40.0	—
Net Proceeds from Issuance of Long-Term Debt	496.1	—	—
Net Proceeds from Issuance (Repurchase) of Common Stock	10.3	(0.6)	26.0
Dividends Paid on Common Stock	(118.8)	(114.6)	(109.5)
Excess Tax (Costs) Benefits Associated with Stock-Based Compensation Awards	1.0	(1.2)	13.2
Net Decrease in Cash and Temporary Cash Investments	$ (5.9)	$(316.7)	$ (12.9)

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 and the gain on sale of discontinued operations.

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 $660.8 million in 2012, an increase of $0.3 million compared with the $660.5 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. Mostly offsetting the 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.

Net cash provided by operating activities totaled $660.5 million in 2011, an increase of $213.5 million compared with the $447.0 million provided by operating activities in 2010. The increase is primarily due to higher cash receipts from the sale of natural gas production in the Exploration and Production segment. From a consolidated perspective, the Company's cash provided by operating activities also increased during 2011 due to income tax refunds received during the year as compared to income taxes paid during 2010.

INVESTING CASH FLOW

Expenditures for Long-Lived Assets

The Company's expenditures from continuing operations for long-lived assets totaled $977.4 million, $854.2 million and $501.4 million in 2012, 2011 and 2010, 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		
	2012	2011	2010
		(Millions)	
Utility:			
Capital Expenditures	$ 58.3	$ 58.4	$ 58.0
Pipeline and Storage:			
Capital Expenditures	144.2(1)	129.2(2)	37.9
Exploration and Production:			
Capital Expenditures	693.8(1)	648.8(2)	398.2(3)
All Other and Corporate:			
Capital Expenditures	81.1(1)	17.8(2)	7.3(4)
Total Expenditures from Continuing Operations	$977.4	$854.2	$501.4

(1) 2012 capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment and the All Other category include $38.9 million, $2.7 million and $11.0 million, respectively, of accounts payable and accrued liabilities related to capital expenditures.

(2) 2011 capital expenditures for the Exploration and Production segment, the Pipeline and Storage segment and the All Other category include $103.3 million, $7.3 million and $1.4 million, respectively, of accounts payable and accrued liabilities related to capital expenditures.

(3) 2010 capital expenditures for the Exploration and Production segment include $78.6 million of accounts payable and accrued liabilities related to capital expenditures.

(4) Excludes expenditures for long-lived assets associated with discontinued operations of $0.1 million for 2010.

Utility

The majority of the Utility capital expenditures for 2012, 2011 and 2010 were made for replacement of mains and main extensions, as well as for the replacement of service lines.

Pipeline and Storage

The majority of the Pipeline and Storage capital expenditures for 2012 were related to the construction of Empire's Tioga County Extension Project ($24.1 million), Supply Corporation's Line N Expansion Project ($2.9 million), Supply Corporation's Line N 2012 Expansion Project ($30.5 million) and Supply Corporation's Northern Access expansion project ($50.8 million), as discussed below. The Pipeline and Storage 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 and 2010 were related to additions, improvements, and replacements to this segment's transmission and gas storage systems. In addition, the Pipeline and Storage capital expenditures for 2011 include $18.1 million spent on the Line N Expansion Project, $8.1 million spent on the Lamont Phase II Project and $31.8 million spent on the Tioga County Extension Project. The Pipeline and Storage capital expenditure amounts for 2010 also include $6.0 million spent on the Lamont Project.

Exploration and Production

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 will be the operator on 4,600 net acres and will have 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.

In 2010, the Exploration and Production segment capital expenditures were primarily well drilling and completion expenditures and included approximately $355.7 million for the Appalachian region (including $332.4 million in the Marcellus Shale area), $27.6 million for the West Coast region and $14.9 million for the Gulf Coast region, the majority of which was for the off-shore program in the shallow waters of the Gulf of Mexico. These amounts included approximately $28.9 million spent to develop proved undeveloped reserves. The capital expenditures in the Appalachian region included the Company's acquisition of two tracts of leasehold acreage for approximately $71.8 million. The Company acquired these tracts in order to expand its Marcellus Shale acreage holdings. These tracts, consisting of approximately 18,000 net acres in Tioga and Potter Counties in Pennsylvania, are geographically similar to the Company's existing Marcellus Shale acreage in the area. The transaction closed on March 12, 2010.

All Other and Corporate

In 2012 and 2011, the majority of the All Other category's capital expenditures for long-lived assets were primarily for the construction of Midstream Corporation's Trout Run Gathering System and the expansion of Midstream Corporation's Covington Gathering System, as discussed below.

In 2010, the majority of the All Other category's capital expenditures for long-lived assets were for the construction of Midstream Corporation's Covington Gathering System, which was placed in service during fiscal 2010.

NFG Midstream Trout Run, LLC, a wholly owned subsidiary of Midstream Corporation, is developing a gathering system in Lycoming County, Pennsylvania. The project, Trout Run Gathering System, was placed in service in May 2012. The current system consists of approximately 26 miles of backbone and in-field gathering system. The complete buildout is expected to include additional in-field gathering pipelines and compression at a cost of approximately $185 million. As of September 30, 2012, the Company has spent approximately $80.1 million in costs related to this project, including approximately $64.5 million spent during the year ended September 30, 2012, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2012.

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, 2012, the Company has spent approximately $28.5 million in costs related to the Covington Gathering System, including approximately $12.2 million spent during the year ended September 30, 2012. All costs associated with this gathering system are included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2012.

On September 17, 2010, the Company completed the sale of its sawmill in Marienville, Pennsylvania, including approximately 23 million board feet of logs and timber consisting of yard inventory along with unexpired timber cutting contracts and certain land and timber holdings designed to provide the purchaser with a supply of logs for the mill. Despite this sale, the Company has retained substantially all of its land and timber holdings, along with mineral rights on land that was sold. The Company will maintain a forestry operation; however, as part of this change in focus, the Company no longer processes lumber products. The Company received proceeds of approximately $15.8 million from the sale. In addition, the purchaser assumed approximately $7.4 million in payment obligations under the Company's timber cutting contracts with various timber suppliers. There was not a material impact to earnings from this sale.

Estimated Capital Expenditures

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

	Year Ended September 30		
	2013	2014	2015
		(Millions)	
Utility	$ 66.3	$ 66.3	$ 68.5
Pipeline and Storage	78.4	133.4	107.4
Exploration and Production(1)	485.0	544.9	494.5
All Other	59.4	78.9	30.0
	$689.1	$823.5	$700.4

(1) Includes estimated expenditures for the years ended September 30, 2013, 2014 and 2015 of approximately $160 million, $206 million and $91 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 2013 through 2015 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 2013 through 2015 also include amounts for the replacement of its legacy mainframe systems.

Pipeline and Storage

Capital expenditures for the Pipeline and Storage segment in 2013 through 2015 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 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, 2012, the total amount reserved for the Pipeline and Storage segment's preliminary survey and investigation costs was $7.4 million.

Supply Corporation and Empire are moving forward with several projects designed to move anticipated Marcellus production gas to other interstate pipelines and to markets beyond the Supply Corporation and Empire pipeline systems.

Supply Corporation has a precedent agreement with Statoil Natural Gas LLC ("Statoil") to provide 320,000 Dth/day of firm transportation capacity for a 20-year term in conjunction with Supply Corporation's "Northern Access" expansion project, and has executed the transportation service agreement. This capacity will provide 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 expected by the end of December 2012. The cost estimate for the Northern Access expansion is $75 million of which approximately $53.9 million has been spent through September 30, 2012 and has been capitalized as Construction Work in Progress. The remainder is expected to be spent in fiscal 2013 and is included as Pipeline and Storage segment capital expenditures in the table above.

Supply Corporation has begun service under two service agreements which total 160,000 Dth/day of firm transportation capacity in its "Line N Expansion Project." This project allows Marcellus production located in the vicinity of Line N to flow south and access markets at Texas Eastern's Holbrook Station ("TETCO Holbrook") in southwestern Pennsylvania. The FERC issued the NGA Section 7(c) certificate on December 16, 2010, and the project was placed into service on October 19, 2011. Completed cost for the Line N Expansion Project is expected to be approximately $22 million. As of September 30, 2012, approximately $21.1 million has been spent on the Line N Expansion Project, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2012.

Supply Corporation has also executed three service agreements for a total of 163,000 Dth/day of additional capacity on Line N to TETCO Holbrook for service beginning November 2012 ("Line N 2012

Expansion Project"). On July 8, 2011, Supply Corporation filed for FERC authorization to construct 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. The FERC issued the NGA Section 7(c) Certificate on March 29, 2012. On October 3, 2012, Supply Corporation put in service a portion of the Project facilities and began early interim service for Range Resources, and began full service for all Project shippers on November 1, 2012. The preliminary cost estimate for the Line N 2012 Expansion Project is approximately $34.1 million for the incremental capacity plus approximately $8.9 million allocated to system replacement. Of this amount, approximately $32.9 million has been spent on the Line N 2012 Expansion Project through September 30, 2012, all of which has been capitalized as Construction Work in Progress. The remainder is expected to be spent in fiscal 2013 and is included as Pipeline and Storage segment estimated capital expenditures in the table above.

On August 4, 2011, Supply Corporation concluded an Open Season to increase its capability to move gas north on its Line N system and deliver gas to Tennessee Gas Pipeline at Mercer, Pennsylvania, a pooling point recently established at Tennessee's Station 219 ("Mercer Expansion Project"). Supply Corporation is continuing discussions with several prospective shippers that would take up to 150,000 Dth/day of the capacity on the project. Service may begin in late 2013 or 2014 and the estimated cost is up to $25 million to $30 million, depending on shipper subscription. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above. As of September 30, 2012, less than $0.1 million has been spent to study the Mercer Expansion Project, all of which has been included in preliminary survey and investigation charges and has been fully reserved for at September 30, 2012.

Empire has begun service under two service agreements which total 350,000 Dth/day of incremental firm transportation capacity in its "Tioga County Extension Project." This project transports Marcellus production from new interconnections at the southern terminus of a 15-mile extension of its Empire Connector line, in Tioga County, Pennsylvania. Completed cost for the Tioga County Extension Project is expected to be approximately $57.5 million, of which approximately $55.9 million has been spent through September 30, 2012. This project enables shippers to deliver their natural gas at existing Empire interconnections with Millennium Pipeline at Corning, New York, with the TransCanada Pipeline at the Niagara River at Chippawa, and with utility and power generation markets along its path, as well as to the new interconnection with TGP's 200 Line (Zone 5) in Ontario County, New York. The FERC issued the NGA Section 7(c) certificate on May 19, 2011 and the project was placed fully in service on November 22, 2011. All costs associated with the project are included in Property, Plant and Equipment on the Consolidated Balance Sheet at September 30, 2012.

On December 17, 2010, Empire concluded an Open Season for up to 260,000 Dth/day of additional capacity from Tioga County, Pennsylvania, to TransCanada Pipeline and the TGP 200 Line, as well as additional short-haul capacity to Millennium Pipeline at Corning ("Central Tioga County Extension"). Empire is in discussions with an anchor shipper for a significant portion of the proposed capacity, with service commencing in 2014 or 2015, likely tied to a rebound in commodity pricing due to the dry gas nature of this area of the Marcellus. The Central Tioga County Extension project may involve up to 25,000 horsepower of compression at up to three new stations and a 25 mile 24" pipeline extension, at a preliminary cost estimate of $135 million. These expenditures are included as Pipeline and Storage segment estimated capital expenditures in the table above. As of September 30, 2012, 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, 2012.

Supply Corporation continues to market the "W2E Overbeck to Leidy" pipeline project, which is designed to transport locally produced Marcellus natural gas supplies, principally from the dry gas central area of the formation, to the Ellisburg/Leidy/Corning area. At full development the W2E Overbeck to Leidy project is designed to transport at least 425,000 Dth/day, and involves construction of a new 82-mile pipeline through Elk, Cameron, Clinton, Clearfield and Jefferson Counties to the Leidy Hub, from Marcellus and other producing areas along over 300 miles of Supply Corporation's existing pipeline system. The project would include a total of approximately 25,000 horsepower of compression at two separate stations. Supply

Corporation has no active filing before the FERC but would restart that process upon the development of an adequate market to support the estimated $290 million capital cost of the project. As of September 30, 2012, approximately $5.7 million has been spent to study the W2E Overbeck to Leidy project, which has been included in preliminary survey and investigation charges and has been fully reserved for at September 30, 2012.

Exploration and Production

Estimated capital expenditures in 2013 for the Exploration and Production segment include approximately $405.3 million for the Appalachian region and $79.7 million for the West Coast region.

Estimated capital expenditures in 2014 for the Exploration and Production segment include approximately $480.1 million for the Appalachian region and $64.8 million for the West Coast region.

Estimated capital expenditures in 2015 for the Exploration and Production segment include approximately $433.1 million for the Appalachian region and $61.4 million for the West Coast region.

All Other and Corporate

Capital expenditures in 2013 through 2015 for the All Other and Corporate category are expected to primarily be for the continued construction of the Covington Gathering System and the Trout Run Gathering System as well as the construction of several smaller gathering systems.

Midstream Corporation is planning the construction of several smaller gathering systems. As of September 30, 2012, the Company has spent approximately $3.1 million in costs related to these projects, all of which has been capitalized as Construction Work in Progress.

Project Funding

The Company has been financing the Pipeline and Storage segment projects and the Midstream Corporation projects mentioned above, as well as the Exploration and Production segment capital expenditures, with cash from operations and short-term borrowings. The Company also issued additional long-term debt in December 2011 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 continue to use short-term borrowings during fiscal 2013, as well as the issuance of additional long-term debt in fiscal 2013. 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 increased $131.0 million when comparing the balance sheet at September 30, 2012 to the balance sheet at September 30, 2011. The maximum amount of short-term debt outstanding during the year ended September 30, 2012 was $327.8 million. The Company used its $500.0 million long-term debt issuance in December 2011 to substantially reduce its short-term debt. The Company continues to consider short-term debt (consisting of short-term notes payable to banks and commercial paper) an important source of cash for temporarily financing capital expenditures and investments in corporations and/or partnerships, gas-in-storage inventory, unrecovered purchased gas costs, margin calls on derivative financial instruments, exploration and development expenditures, repurchases of stock, other working capital needs and repayment of long-term debt. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt. At 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.

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, 2012, 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, 2012, 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, 2012, the Company's debt to capitalization ratio (as calculated under the facility) was .44. The constraints specified in the committed credit facility would have permitted an additional $2.07 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, 2012, the Company would have been permitted to issue up to a maximum of $1.51 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 7.1%) of the Company's long-term debt (as of September 30, 2012) 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, 2012, the Company did not have any debt outstanding under the committed credit facility.

The Company's embedded cost of long-term debt was 6.17% at September 30, 2012 and 6.85% at September 30, 2011. Refer to "Interest Rate Risk" in this Item for a more detailed breakdown of the Company's embedded cost of long-term debt.

Current Portion of Long-Term Debt at September 30, 2012 consists of $250.0 million of 5.25% notes that mature in March 2013. Currently, the Company expects to refund these notes in fiscal 2013 with cash on hand, short-term borrowings and/or long-term debt. The Company repaid $150.0 million of 6.70% notes that matured on November 21, 2011, which had been classified as Current Portion of Long-Term Debt at September 30, 2011.

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 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 $108.9 million. These leases have been entered into for the use of compressors, drilling rigs, buildings, meters and other items and are accounted for as operating leases.

CONTRACTUAL OBLIGATIONS

The following table summarizes the Company's expected future contractual cash obligations as of September 30, 2012, and the twelve-month periods over which they occur:

	Payments by Expected Maturity Dates						
	2013	2014	2015	2016	2017	Thereafter	Total
				(Millions)			
Long-Term Debt, including interest expense(1)	$328.6	$73.2	$73.2	$73.2	$73.2	$1,344.6	$1,966.0
Operating Lease Obligations	$ 38.7	$37.0	$13.2	$ 5.8	$ 5.7	$ 8.5	$ 108.9
Purchase Obligations:							
Gas Purchase Contracts(2)	$216.5	$ 6.1	$ 2.1	$ 0.5	$ 0.1	$ —	$ 225.3
Transportation and Storage Contracts	$ 61.6	$62.0	$62.0	$59.7	$32.2	$ 66.6	$ 344.1
Hydraulic Fracturing and Fuel Obligations	$ 60.7	$11.4	$ —	$ —	$ —	$ —	$ 72.1
Pipeline and Gathering System Expansion Projects	$ 40.7	$ —	$ —	$ —	$ —	$ —	$ 40.7
Other	$ 31.7	$ 7.3	$ 6.3	$ 5.5	$ 4.3	$ 10.5	$ 65.6

(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, workers compensation liabilities and liabilities for income tax uncertainties).

The Company has made certain other guarantees on behalf of its subsidiaries. The guarantees relate primarily to: (i) obligations under derivative financial instruments, which are included on the Consolidated Balance Sheets in accordance with the authoritative guidance (see Item 7, MD&A under the heading "Critical Accounting Estimates — Accounting for Derivative Financial Instruments"); (ii) NFR obligations to purchase gas or to purchase gas transportation/storage services where the amounts due on those obligations each month are included on the Consolidated Balance Sheets as a current liability; and (iii) other obligations which are reflected on the Consolidated Balance Sheets. The Company believes that the likelihood it would be required to make payments under the guarantees is remote, and therefore has not included them in the table above.

OTHER MATTERS

In addition to the environmental and other matters discussed in this Item 7 and in Item 8 at Note I — Commitments and Contingencies, the Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations or other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these normal-course matters could have a material effect on earnings and cash flows in the period in which they are resolved, they are not expected to change materially the Company's present liquidity position, nor are they expected to have a material adverse effect on the financial condition of the Company.

The Company has a tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) that covers approximately half of the Company's employees. 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 2012, the Company contributed $44.0 million to the Retirement Plan. The Company anticipates that the annual contribution to the Retirement Plan in 2013 will be in the range of $30.0 million to $45.0 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 2013 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 currently in the process of 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 2012, the Company contributed $21.2 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 2013 will be in the range of $15.0 million to $20.0 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, in its Exploration and Production segment, Energy Marketing segment and Pipeline and Storage segment, uses or has used 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. 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, 2012 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. 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 capital and margin costs through higher 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 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. Given the high level of historical correlation between NYMEX prices and prices at 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 $19.7 million at September 30, 2012 and represent 24.8% of the Total Net Assets shown in Item 8 at Note F — Fair Value Measurements at September 30, 2012.

The increase in the net fair value liability of the Level 3 positions from October 1, 2011 to September 30, 2012, as shown in Item 8 at Note F, was attributable to an increase 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, 2012.

The reduction in the derivative liabilities (due to an assessment of the Company's credit risk) was larger than the reduction in derivative assets (due to an assessment of counterparty credit risk) resulting in a $1.0 million increase in Net Derivative Assets. The Company applied default probabilities to the anticipated cash flows that it was expecting to receive and pay to its counterparties to calculate the credit reserve.

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, 2012. At September 30, 2012, the Company had not entered into any natural gas or crude oil price swap agreements extending beyond 2017.

Natural Gas Price Swap Agreements

	Expected Maturity Dates					
	2013	2014	2015	2016	2017	Total
Notional Quantities (Equivalent Bcf)	50.5	29.4	18.1	18.0	17.9	133.9
Weighted Average Fixed Rate (per Mcf)	$4.76	$4.26	$4.07	$4.07	$4.07	$ 4.37
Weighted Average Variable Rate (per Mcf)	$3.85	$4.24	$4.43	$4.56	$4.68	$ 4.22

Of the total Bcf above, 0.4 Bcf is accounted for as fair value hedges at a weighted average fixed rate of $6.12 per Mcf. The remaining 133.5 Bcf are accounted for as cash flow hedges at a weighted average fixed rate of $4.37 per Mcf.

Crude Oil Price Swap Agreements

	Expected Maturity Dates		
	2013	2014	Total
Notional Quantities (Equivalent bbls)	1,596,000	720,000	2,316,000
Weighted Average Fixed Rate (per bbl)	$ 93.33	$ 96.28	$ 94.24
Weighted Average Variable Rate (per bbl)	$ 103.58	$ 102.31	$ 103.19

At September 30, 2012, the Company would have received from its respective counterparties an aggregate of approximately $21.8 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 $20.3 million to terminate the crude oil price swap agreements outstanding at September 30, 2012.

At September 30, 2011, the Company had natural gas price swap agreements covering 66.5 Bcf at a weighted average fixed rate of $5.78 per Mcf. The Company also had crude oil price swap agreements covering 2,736,000 bbls at a weighted average fixed rate of $81.38 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, 2012, the Company held no futures contracts with maturity dates extending beyond 2016.

Futures Contracts

	Expected Maturity Dates				
	2013	2014	2015	2016	Total
Net Contract Volume Purchased (Sold) (Equivalent Bcf)	—(1)	1.8	0.1	—(2)	1.9
Weighted Average Contract Price (per Mcf)	$3.97	$4.21	$4.85	$5.21	$4.03
Weighted Average Settlement Price (per Mcf)	$3.90	$4.01	$4.24	$4.60	$3.93

(1) The Energy Marketing segment has long (purchased) contracts covering 6.5 Bcf of gas and short (sold) contracts covering 6.5 Bcf of gas in 2013.

(2) The Energy Marketing segment has long (purchased) contracts covering less than 0.1 Bcf of gas and short (sold) contracts covering less than 0.1 Bcf of gas in 2016.

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. These contracts are 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 to due to the fixed price gas sales commitments that it enters into with certain residential, commercial, industrial, public authority and wholesale customers. The Company would have received $0.4 million to terminate these contracts at September 30, 2012.

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. Of this amount, 5.7 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 1.1 Bcf is accounted for as fair value hedges used to hedge against falling prices, a risk to which the Energy Marketing segment is exposed to due to the fixed price gas purchase commitments that it enters into with certain natural gas suppliers. The Company would have received $1.2 million to terminate these contracts at September 30, 2012.

At September 30, 2011, the Company had long (purchased) contracts covering 8.6 Bcf of gas extending through 2014 at a weighted average contract price of $5.21 per Mcf and a weighted average settlement price of $4.30 per Mcf.

At September 30, 2011, the Company had short (sold) contracts covering 6.3 Bcf of gas extending through 2013 at a weighted average contract price of $5.04 per Mcf and a weighted average settlement price of $4.32 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 twelve counterparties of which four are in a net gain position. On average, the Company had $6.4 million of credit exposure per counterparty in a gain position at September 30, 2012. The maximum credit exposure per counterparty in a gain position at September 30, 2012 was $11.0 million. As of September 30, 2012, 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, 2012, ten of the twelve 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 current liability were larger) and/or the Company's credit rating declined, then additional hedging collateral deposits may be required. At September 30, 2012, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $14.0 million according to the Company's internal model (discussed in Item 8 at Note F — Fair Value Measurements). At September 30, 2012, the fair market value of the derivative financial instrument liabilities with a credit-risk related contingency feature was $23.9 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, which were in a liability position, the Company was not required to post any hedging collateral deposits at September 30, 2012.

For its exchange traded futures contracts, which are in a liability position, the Company had posted $0.4 million in hedging collateral deposits as of September 30, 2012. 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 $1.6 billion at September 30, 2012. 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						
	2013	2014	2015	2016	2017	Thereafter	Total
	(Dollars in millions)						
Long-Term Fixed Rate Debt	$250.0	$—	$—	$—	$—	$1,149.0	$1,399.0
Weighted Average Interest Rate Paid	5.3%	—	—	—	—	6.4%	6.2%

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 are changed only when approved through a procedure known as a "rate case." Currently neither division has a rate case on file. 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. The rate order approved a revenue increase of $1.8 million annually, together with a surcharge that would collect up to $10.8 million to cover expenses for implementation of an efficiency and conservation incentive program. The rate order further provided for a return on equity of 9.1%. In connection with the 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. The Company surcharges or credits any difference from the average weather normalized usage per customer account. The surcharge or credit is calculated to recover total margin for the most recent twelve-month period ending December 31, and is applied to customer bills annually, beginning March 1st.

On April 18, 2008, Distribution Corporation filed an appeal with Supreme Court, Albany County, seeking review of the 2007 rate order. The appeal contended, among other things, that the NYPSC improperly disallowed recovery of certain environmental clean-up costs. Following further appeals, on March 29, 2011, the Court of Appeals, the state's highest court, issued a judgment and opinion in favor of Distribution Corporation. The matter was remanded to the NYPSC to be implemented consistent with the decision of the court.

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 filed a general rate case with the FERC on October 31, 2011, proposing rate increases to be effective December 1, 2011. The parties on April 17, 2012 reached an agreement in principle to settle the rate case at rates generally lower than the rates proposed in October 2011 by Supply Corporation. On August 6, 2012, the FERC issued an order approving the settlement.

The settlement provides for, among other things, (i) an increase in Supply Corporation's base tariff rates effective May 1, 2012, based on a "black box" overall cost of service of $166,500,000 per year rather than a stated rate of return, (ii) implementation of a tracking mechanism to adjust fuel retention rates annually to reflect actual experience, replacing the previously fixed fuel retention rates, (iii) a requirement that its next general rate case be filed no later than January 1, 2016, (iv) the elimination of a regulatory liability associated with its postretirement benefit plans, (v) lower and more detailed depreciation rates, and (vi) the "roll-in" of the costs of certain incrementally-priced firm transportation services into system-wide "postage stamp" rates, replacing the previous zoned rates for certain firm transportation services originating at the Niagara import point.

Empire's facilities known as the Empire Connector project were placed into service on December 10, 2008. As of that date, Empire became an interstate pipeline subject to FERC regulation, performing services under a FERC-approved tariff and at FERC-approved rates. The December 21, 2006 FERC order issuing Empire its NGA Section 7(c) Certificate required Empire to file a cost and revenue study at the FERC following three years of actual operation as an interstate pipeline, in conjunction with which Empire was directed either to justify Empire's existing recourse rates or to propose alternative rates. Empire satisfied this obligation on March 14, 2012 by filing a cost and revenue study based on the twelve months ended December 31, 2011, and did not propose alternative rates. The FERC has not yet responded to Empire's filing or issued any notice setting a deadline for others to respond.

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, 2012, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites will be in the range of $15.4 million to $19.6 million. The minimum estimated liability of $15.4 million has been recorded in Other Deferred Credits on the Consolidated Balance Sheet at September 30, 2012. 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 will 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 June 2011, the FASB issued authoritative guidance regarding the presentation of comprehensive income. The new guidance allows companies only two choices for presenting net income and other comprehensive income: in a single continuous statement, or in two separate, but consecutive, statements. The guidance eliminates the current option to report other comprehensive income and its components in the statement of changes in equity. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2013 and is not expected to have a significant impact on the Company's financial statements.

In September 2011, the FASB issued revised authoritative guidance that simplifies the testing of goodwill for impairment. The revised guidance allows companies the option to perform a "qualitative" assessment to determine whether further impairment testing is necessary. The revised authoritative guidance is required to be effective for the Company's annual impairment test performed in fiscal 2013. The Company has adopted the new provisions for fiscal 2012, as early adoption was permitted.

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.

EFFECTS OF INFLATION

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

SAFE HARBOR FOR FORWARD-LOOKING STATEMENTS

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

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

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

5. Uncertainty of oil and gas reserve estimates;

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

7. Changes in demographic patterns and weather conditions;

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

9. 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;

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 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.

Item 8 *Financial Statements and Supplementary Data*

Index to Financial Statements

Financial Statements:

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

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, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended September 30, 2012 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, 2012, 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 21, 2012

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF INCOME AND EARNINGS REINVESTED IN THE BUSINESS

	Year Ended September 30		
	2012	2011	2010
	(Thousands of dollars, except per common share amounts)		
INCOME			
Operating Revenues	$ 1,626,853	$ 1,778,842	$ 1,760,503
Operating Expenses			
Purchased Gas	415,589	628,732	658,432
Operation and Maintenance	401,397	400,519	394,569
Property, Franchise and Other Taxes	90,288	81,902	75,852
Depreciation, Depletion and Amortization	271,530	226,527	191,199
	1,178,804	1,337,680	1,320,052
Operating Income	448,049	441,162	440,451
Other Income (Expense):			
Gain on Sale of Unconsolidated Subsidiaries	—	50,879	—
Other Income	5,133	5,947	6,126
Interest Income	3,689	2,916	3,729
Interest Expense on Long-Term Debt	(82,002)	(73,567)	(87,190)
Other Interest Expense	(4,238)	(4,554)	(6,756)
Income from Continuing Operations Before Income Taxes	370,631	422,783	356,360
Income Tax Expense	150,554	164,381	137,227
Income from Continuing Operations	220,077	258,402	219,133
Discontinued Operations:			
Income from Operations, Net of Tax	—	—	470
Gain on Disposal, Net of Tax	—	—	6,310
Income from Discontinued Operations, Net of Tax	—	—	6,780
Net Income Available for Common Stock	220,077	258,402	225,913
EARNINGS REINVESTED IN THE BUSINESS			
Balance at Beginning of Year	1,206,022	1,063,262	948,293
	1,426,099	1,321,664	1,174,206
Dividends on Common Stock	(119,815)	(115,642)	(110,944)
Balance at End of Year	$ 1,306,284	$ 1,206,022	$ 1,063,262
Earnings Per Common Share:			
Basic:			
Income from Continuing Operations	$ 2.65	$ 3.13	$ 2.70
Income from Discontinued Operations	—	—	0.08
Net Income Available for Common Stock	$ 2.65	$ 3.13	$ 2.78
Diluted:			
Income from Continuing Operations	$ 2.63	$ 3.09	$ 2.65
Income from Discontinued Operations	—	—	0.08
Net Income Available for Common Stock	$ 2.63	$ 3.09	$ 2.73
Weighted Average Common Shares Outstanding:			
Used in Basic Calculation	83,127,844	82,514,015	81,380,434
Used in Diluted Calculation	83,739,771	83,670,802	82,660,598

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED BALANCE SHEETS

	At September 30 2012	At September 30 2011
	(Thousands of dollars)	
ASSETS		
Property, Plant and Equipment	$6,615,813	$5,646,918
Less — Accumulated Depreciation, Depletion and Amortization	1,876,010	1,646,394
	4,739,803	4,000,524
Current Assets		
Cash and Temporary Cash Investments	74,494	80,428
Hedging Collateral Deposits	364	19,701
Receivables — Net of Allowance for Uncollectible Accounts of $30,317 and $31,039, Respectively	115,818	131,885
Unbilled Utility Revenue	19,652	17,284
Gas Stored Underground	49,795	54,325
Materials and Supplies — at average cost	28,577	27,932
Other Current Assets	56,121	64,923
Deferred Income Taxes	10,755	15,423
	355,576	411,901
Other Assets		
Recoverable Future Taxes	150,941	144,377
Unamortized Debt Expense	13,409	10,571
Other Regulatory Assets	546,851	484,397
Deferred Charges	7,591	5,552
Other Investments	86,774	79,365
Goodwill	5,476	5,476
Fair Value of Derivative Financial Instruments	27,616	76,085
Other	1,105	2,836
	839,763	808,659
Total Assets	$5,935,142	$5,221,084
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders' Equity		
Common Stock, $1 Par Value		
Authorized — 200,000,000 Shares; Issued and Outstanding — 83,330,140 Shares and 82,812,677 Shares, Respectively	$ 83,330	$ 82,813
Paid In Capital	669,501	650,749
Earnings Reinvested in the Business	1,306,284	1,206,022
Total Common Shareholders' Equity Before Items of Other Comprehensive Loss	2,059,115	1,939,584
Accumulated Other Comprehensive Loss	(99,020)	(47,699)
Total Comprehensive Shareholders' Equity	1,960,095	1,891,885
Long-Term Debt, Net of Current Portion	1,149,000	899,000
Total Capitalization	3,109,095	2,790,885
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	171,000	40,000
Current Portion of Long-Term Debt	250,000	150,000
Accounts Payable	87,985	126,709
Amounts Payable to Customers	19,964	15,519
Dividends Payable	30,416	29,399
Interest Payable on Long-Term Debt	29,491	25,512
Customer Advances	24,055	19,643
Customer Security Deposits	17,942	17,321
Other Accruals and Current Liabilities	79,099	108,636
Fair Value of Derivative Financial Instruments	24,527	9,728
	734,479	542,467
Deferred Credits		
Deferred Income Taxes	1,065,757	955,384
Taxes Refundable to Customers	66,392	65,543
Unamortized Investment Tax Credit	2,005	2,586
Cost of Removal Regulatory Liability	139,611	135,940
Other Regulatory Liabilities	21,014	17,177
Pension and Other Post-Retirement Liabilities	516,197	481,520
Asset Retirement Obligations	119,246	75,731
Other Deferred Credits	161,346	153,851
	2,091,568	1,887,732
Commitments and Contingencies	—	—
Total Capitalization and Liabilities	$5,935,142	$5,221,084

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended September 30		
	2012	2011	2010
	(Thousands of dollars)		
Operating Activities			
Net Income Available for Common Stock	$ 220,077	$ 258,402	$ 225,913
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:			
Gain on Sale of Unconsolidated Subsidiaries	—	(50,879)	—
Gain on Sale of Discontinued Operations	—	—	(10,334)
Depreciation, Depletion and Amortization	271,530	226,527	191,809
Deferred Income Taxes	144,150	164,251	134,679
Excess Tax Costs (Benefits) Associated with Stock-Based Compensation Awards	(985)	1,224	(13,207)
Elimination of Other Post-Retirement Regulatory Liability	(21,672)	—	—
Other	12,952	15,651	9,220
Change in:			
Hedging Collateral Deposits	19,337	(8,567)	(10,286)
Receivables and Unbilled Utility Revenue	13,859	3,887	10,262
Gas Stored Underground and Materials and Supplies	5,405	(9,934)	6,546
Other Current Assets	9,790	83,245	(37,407)
Accounts Payable	(14,996)	20,292	(4,616)
Amounts Payable to Customers	4,445	(22,590)	(67,669)
Customer Advances	4,412	(7,995)	3,083
Customer Security Deposits	621	(999)	890
Other Accruals and Current Liabilities	10,633	242	(682)
Other Assets	(10,733)	15,259	7,970
Other Liabilities	(8,038)	(27,470)	861
Net Cash Provided by Operating Activities	660,787	660,546	447,032
Investing Activities			
Capital Expenditures	(1,036,784)	(820,872)	(443,101)
Net Proceeds from Sale of Unconsolidated Subsidiaries	—	59,365	—
Net Proceeds from Sale of Timber Mill and Related Assets	—	—	15,770
Net Proceeds from Sale of Landfill Gas Pipeline Assets	—	—	38,000
Net Proceeds from Sale of Oil and Gas Producing Properties	—	63,501	—
Other	446	(2,908)	(251)
Net Cash Used in Investing Activities	(1,036,338)	(700,914)	(389,582)
Financing Activities			
Change in Notes Payable to Banks and Commercial Paper	131,000	40,000	—
Excess Tax (Costs) Benefits Associated with Stock-Based Compensation Awards	985	(1,224)	13,207
Net Proceeds from Issuance of Long-Term Debt	496,085	—	—
Reduction of Long-Term Debt	(150,000)	(200,000)	—
Net Proceeds from Issuance (Repurchase) of Common Stock	10,345	(592)	26,057
Dividends Paid on Common Stock	(118,798)	(114,559)	(109,596)
Net Cash Provided By (Used in) Financing Activities	369,617	(276,375)	(70,332)
Net Decrease in Cash and Temporary Cash Investments	(5,934)	(316,743)	(12,882)
Cash and Temporary Cash Investments At Beginning of Year	80,428	397,171	410,053
Cash and Temporary Cash Investments At End of Year	$ 74,494	$ 80,428	$ 397,171
Supplemental Disclosure of Cash Flow Information			
Cash Paid For:			
Interest	$ 81,051	$ 81,966	$ 93,333
Income Taxes (Refunded)	$ 474	$ (63,105)	$ 30,975

See Notes to Consolidated Financial Statements

NATIONAL FUEL GAS COMPANY

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended September 30		
	2012	2011	2010
	(Thousands of dollars)		
Net Income Available for Common Stock	$220,077	$258,402	$225,913
Other Comprehensive Income (Loss), Before Tax:			
Decrease in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	(27,552)	(24,172)	(30,155)
Reclassification Adjustment for Amortization of Prior Year Funded Status of the Pension and Other Post-Retirement Benefit Plans	10,270	8,536	5,000
Foreign Currency Translation Adjustment	—	17	53
Reclassification Adjustment for Realized Foreign Currency Translation Loss in Net Income	—	34	—
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	3,545	(1,199)	(2,195)
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(7,248)	30,238	65,366
Reclassification Adjustment for Realized Gains on Derivative Financial Instruments in Net Income	(65,691)	(15,485)	(41,320)
Other Comprehensive Loss, Before Tax	(86,676)	(2,031)	(3,251)
Income Tax Benefit Related to the Decrease in the Funded Status of the Pension and Other Post-Retirement Benefit Plans	(10,144)	(8,735)	(11,379)
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	3,836	3,221	1,887
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	1,311	(453)	(831)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(8,244)	12,836	26,628
Reclassification Adjustment for Income Tax Expense on Realized Gains on Derivative Financial Instruments in Net Income	(22,114)	(6,186)	(16,967)
Income Taxes — Net	(35,355)	683	(662)
Other Comprehensive Loss	(51,321)	(2,714)	(2,589)
Comprehensive Income	$168,756	$255,688	$223,324

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. The equity method is used to account for entities in which the Company has a non-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. This includes the reclassification of $63.7 million from Other Regulatory Liabilities to Other Regulatory Assets on the Consolidated Balance Sheet at September 30, 2011. This reclassification pertains to pension and post-retirement benefit regulatory asset and regulatory liability balances. The Company has switched from a "gross" presentation to a "net" presentation, which is consistent with the methodology used by the various regulators in analyzing such regulatory asset and liability balances. This reclassification did not impact the Consolidated Statement of Income and there was an immaterial impact to the Consolidated Statement of Cash Flows.

The Company also reclassified $26.6 million from Other Regulatory Assets to Other Current Assets and $13.8 million from Other Regulatory Liabilities to Other Accruals and Current Liabilities on the Consolidated Balance Sheet at September 30, 2011. The reclassification was made to distinguish long-term regulatory assets and liabilities from current regulatory assets and liabilities. Current regulatory assets are defined as assets recoverable from ratepayers over a twelve-month period. Current regulatory liabilities are defined as liabilities payable to ratepayers over a twelve-month period. These reclassifications did not impact the Consolidated Statement of Income and there was an immaterial impact to the Consolidated Statement of Cash Flows.

Revisions were made on the Consolidated Statement of Cash Flows for the years ended September 30, 2011 and September 30, 2010 to reflect non-cash investing activities embedded in Accounts Payable on the Consolidated Balance Sheets at September 30, 2011, September 30, 2010 and September 30, 2009. These revisions reduced the cash inflow related to Accounts Payable for the years ended September 30, 2011 and September 30, 2010 by $16.7 million and $12.7 million, respectively, and reduced capital expenditures by the same amounts. The effect of these revisions was to reduce Net Cash Provided by Operating Activities for the years ended September 30, 2011 and September 30, 2010 and to reduce Net Cash Used in Investing Activities for the years ended September 30, 2011 and September 30, 2010.

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 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.

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, 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 regulated businesses, as required by regulatory authorities.

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, 2012, 2011, and 2010, estimated future net cash flows were increased by $128.4 million, $35.4 million and $65.4 million, respectively. At September 30, 2012, the ceiling exceeded the book value of the oil and gas properties by approximately $55.3 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.

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	
	2012	2011
	(Thousands)	
Utility	$1,737,645	$1,695,702
Pipeline and Storage	1,406,433	1,260,301
Exploration and Production	2,828,358	2,042,225
Energy Marketing	2,865	2,095
All Other and Corporate	196,593	127,291
	$6,171,894	$5,127,614

Average depreciation, depletion and amortization rates are as follows:

	Year Ended September 30		
	2012	2011	2010
Utility	2.6%	2.6%	2.6%
Pipeline and Storage	2.9%	3.1%	3.0%
Exploration and Production, per Mcfe(1)	$2.25	$2.17	$2.14
Energy Marketing	3.6%	2.5%	2.9%
All Other and Corporate	1.8%	1.3%	6.8%

(1) Amounts include depletion of oil and gas producing properties as well as depreciation of fixed assets. As disclosed in Note N — Supplementary Information for Oil and Gas Producing Properties, depletion of oil and gas producing properties amounted to $2.19, $2.12 and $2.10 per Mcfe of production in 2012, 2011 and 2010, respectively.

Goodwill

The Company has recognized goodwill of $5.5 million as of September 30, 2012 and 2011 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, 2012, 2011 and 2010, the fair value of Empire was greater than its book value. As such, the goodwill was not considered impaired at those dates. Going back to the origination of the goodwill in 2003, the Company has never recorded an impairment of its goodwill balance.

Financial Instruments

Unrealized gains or losses from the Company's investments in an equity mutual fund 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 did not experience any material ineffectiveness with regard to its cash flow hedges during 2012, 2011 or 2010.

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 2012, 2011 or 2010.

Accumulated Other Comprehensive Income (Loss)

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

	Year Ended September 30	
	2012	2011
	(Thousands)	
Funded Status of the Pension and Other Post-Retirement Benefit Plans	$(100,561)	$(89,587)
Net Unrealized Gain (Loss) on Derivative Financial Instruments	(1,602)	40,979
Net Unrealized Gain on Securities Available for Sale	3,143	909
Accumulated Other Comprehensive Loss	$ (99,020)	$(47,699)

At September 30, 2012, it is estimated that $10.6 million of unrealized gains on derivative financial instruments will be reclassified into the Consolidated Statement of Income during 2013 with $12.2 million of unrealized losses 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 2017.

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 $0.4 million and $0.5 million at September 30, 2012 and 2011, respectively. The total amount for accumulated losses was $100.9 million and $90.0 million at September 30, 2012 and 2011, respectively.

Gas Stored Underground — Current

In the Utility segment, gas stored underground — current in the amount of $34.8 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 2012, 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 $46.0 million at September 30, 2012. 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, 2012, the remaining weighted average amortization period for such costs was approximately 4 years.

Income Taxes

The Company and its domestic 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			
	2012	2011	2010	2009
	(Thousands)			
Non-cash Capital Expenditures	$52,557	$111,947	$78,632	$20,231

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, 2012, the Company had hedging collateral deposits of $0.4 million related to its exchange-traded futures contracts. At September 30, 2011, the Company had hedging collateral deposits of $5.5 million related to its exchange-traded futures contracts and $14.2 million related to its over-the-counter crude oil swap agreements. 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	
	2012	2011
	(Thousands)	
Prepayments	$ 8,316	$ 9,489
Prepaid Property and Other Taxes	14,455	13,240
Federal Income Taxes Receivable	268	385
State Income Taxes Receivable	2,065	6,124
Fair Values of Firm Commitments	1,291	9,096
Regulatory Assets	29,726	26,589
	$56,121	$64,923

Other Accruals and Current Liabilities

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

	Year Ended September 30	
	2012	2011
	(Thousands)	
Accrued Capital Expenditures	$36,460	$ 72,121
Regulatory Liabilities	38,253	29,368
Other	4,386	7,147
	$79,099	$108,636

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, 2012 and 2011, customers in the balanced billing programs had advanced excess funds of $24.1 million and $19.6 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, 2012 and 2011, the Company had received customer security deposits amounting to $17.9 million and $17.3 million, respectively.

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 2012, there were 844,872 securities excluded as being antidilutive. For 2011, there were no securities excluded as being antidilutive. For 2010, 314,910 securities were 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 represent the right to receive shares of common stock of the Company (or the equivalent value in cash or a combination of cash and shares of common stock of the Company, as determined by the Company) at the end of a specified time period. These restricted stock units do not entitle the participants to dividend and voting rights. The accounting for these 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, 2012, 2011 and 2010 was approximately $7.2 million, $6.7 million, and $4.4 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, 2012, 2011 and 2010 was approximately $2.9 million, $2.7 million and $1.8 million, respectively. There were no capitalized stock-based compensation costs during the years ended September 30, 2012, 2011 and 2010.

The Company realized tax benefits related to stock-based compensation of $14.2 million, $19.0 million, and $12.8 million for the fiscal years ended September 30, 2012, 2011 and 2010, respectively. The Company only recorded tax benefits of $0.6 million, $0.4 million, and $12.2 million related to the fiscal years ended September 30, 2012, 2011 and 2010, respectively, due to tax loss carryforwards.

For a summary of transactions during 2012 involving option shares, non-performance based SARs, performance based SARs, restricted share awards and 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, 2012, 2011 and 2010 totaled approximately $13.5 million, $44.6 million, and $53.6 million, respectively. For 2012, 2011 and 2010, the amount of cash received by the Company from the exercise of such stock options was approximately $7.6 million, $9.5 million, and $34.5 million, respectively.

There were no stock options granted during the years ended September 30, 2012, 2011 and 2010. For the years ended September 30, 2012 and 2011, no stock options became fully vested. For the year ended September 30, 2010, 100,000 stock options became fully vested. The total fair value of the stock options that became vested during the year ended September 30, 2010 was approximately $0.7 million. There was no unrecognized compensation expense related to stock options at September 30, 2012.

Non-Performance Based SARs

The Company granted 166,000 and 195,000 non-performance based SARs during the years ended September 30, 2012 and 2011, respectively. The Company did not grant any non-performance based SARs during the year ended September 30, 2010. The SARs granted in 2012 will be settled in shares of common stock of the Company. The SARs granted in 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. Non-performance based SARs are considered equity awards under the current authoritative guidance for stock-based compensation. The accounting for non-performance based SARs is the same as the accounting for stock options. The non-performance based 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 non-performance based SARs granted during the year ended September 30, 2011 vest and become exercisable annually in one-third increments. The weighted average grant date fair value of these non-performance based SARs granted during the years ended September 30, 2012 and 2011 were estimated on the date of grant using the same accounting treatment that is applied for stock options.

Participants in the stock option and award plans did not exercise any non-performance based SARs during the years ended September 30, 2012, 2011 and 2010. The weighted average grant date fair value of non-performance based SARs granted in 2012 and 2011 are $11.20 and $15.01, respectively. For the year ended September 30, 2012, 59,990 non-performance based SARs became fully vested. For the year ended September 30, 2011, no non-performance based SARs became fully vested. For the year ended September 30, 2010, 50,000 non-performance based SARs became fully vested. The total fair value of the non-performance based SARs that became vested during the year ended September 30, 2012 was approximately $0.9 million. The total fair value of the non-performance based SARs that became vested during the year ended September 30, 2010 was approximately $0.4 million. As of September 30, 2012, unrecognized compensation expense related to non-performance based SARs totaled approximately $1.1 million, which will be recognized over a weighted average period of 10.2 months.

The fair value of non-performance based 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 non-performance based SARs at the date of grant:

	Year Ended September 30	
	2012	**2011**
Risk Free Interest Rate	1.59%	2.94%
Expected Life (Years)	8.25	8.00
Expected Volatility	24.97%	23.38%
Expected Dividend Yield (Quarterly)	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 non-performance based SARs. The expected life and expected volatility are based on historical experience.

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

Performance Based SARs

The Company did not grant any performance based SARs during the years ended September 30, 2012 and 2011. The Company granted 520,500 performance based SARs during the year ended September 30, 2010. The accounting treatment for performance based SARs is the same as the accounting for stock options under the current authoritative guidance for stock-based compensation. The performance based SARs granted for the year ended September 30, 2010 vest and become exercisable annually in one-third increments, provided that a performance condition is met. The performance condition for each fiscal year, generally stated, is an increase over the prior fiscal year of at least five percent in certain oil and natural gas production of the Exploration and Production segment. The weighted average grant date fair value of the performance based SARs granted during 2010 was estimated on the date of grant using the same accounting treatment that is applied for stock options, and assumes that the performance conditions specified will be achieved. If such conditions are not met or it is not considered probable that such conditions will be met, no compensation expense is recognized and any previously recognized compensation expense is reversed.

The weighted average grant date fair value of performance based SARs granted in 2010 is $12.06 per share. The total intrinsic value of performance based SARs exercised during the years ended September 30, 2012 and 2011 totaled less than $0.1 million and approximately $0.3 million, respectively. Participants in the stock option and award plans did not exercise any performance based SARs during the year ended September 30, 2010. For the years ended September 30, 2012, 2011 and 2010, 375,179, 376,819 and 203,324 performance based SARs became fully vested. The total fair value of the performance based SARs that became vested during each of the years ended September 30, 2012, 2011 and 2010 was approximately $2.9 million, $2.9 million and $0.8 million, respectively. As of September 30, 2012, unrecognized compensation expense related to performance based SARs totaled approximately $0.1 million, which will be recognized over a weighted average period of 3.0 months.

The fair value of performance based 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 performance based SARs at the date of grant:

	Year Ended September 30 2010
Risk Free Interest Rate	3.55%
Expected Life (Years)	7.75
Expected Volatility	23.25%
Expected Dividend Yield (Quarterly)	0.64%

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 performance based SARs. The expected life and expected volatility are based on historical experience.

For grants during the year ended September 30, 2010, it was assumed that there would be no forfeitures, based on the vesting term and the number of grantees.

Restricted Share Awards

The Company granted 41,525, 47,250, and 4,000 restricted share awards (non-vested stock as defined by the current accounting literature) during the years ended September 30, 2012, 2011 and 2010, respectively. The weighted average fair value of restricted share awards granted in 2012, 2011 and 2010 is $55.09 per share, $63.98 per share and $52.10 per share, respectively. As of September 30, 2012, unrecognized compensation expense related to restricted share awards totaled approximately $4.0 million, which will be recognized over a weighted average period of 2.4 years.

Restricted Stock Units

The Company granted 68,450 and 41,800 restricted stock units during the years ended September 30, 2012 and 2011, respectively. The weighted average fair value of restricted share units granted in 2012 and

2011 are $47.10 per share and $59.35 per share, respectively. As of September 30, 2012, unrecognized compensation expense related to restricted share awards totaled approximately $3.9 million, which will be recognized over a weighted average period of 2.0 years.

New Authoritative Accounting and Financial Reporting Guidance

In June 2011, the FASB issued authoritative guidance regarding the presentation of comprehensive income. The new guidance allows companies only two choices for presenting net income and other comprehensive income: in a single continuous statement, or in two separate, but consecutive, statements. The guidance eliminates the current option to report other comprehensive income and its components in the statement of changes in equity. This authoritative guidance will be effective as of the Company's first quarter of fiscal 2013 and is not expected to have a significant impact on the Company's financial statements.

In September 2011, the FASB issued revised authoritative guidance that simplifies the testing of goodwill for impairment. The revised guidance allows companies the option to perform a "qualitative" assessment to determine whether further impairment testing is necessary. The revised authoritative guidance is required to be effective for the Company's annual impairment test performed in fiscal 2013. The Company has adopted the new provisions for fiscal 2012, as early adoption was permitted.

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.

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 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		
	2012	2011	2010
		(Thousands)	
Balance at Beginning of Year	$ 75,731	$101,618	$ 91,373
Liabilities Incurred and Revisions of Estimates	41,653	10,346	16,140
Liabilities Settled	(2,997)	(41,704)	(12,622)
Accretion Expense	4,859	5,471	6,727
Balance at End of Year	$119,246	$ 75,731	$101,618

Note C — Regulatory Matters

Regulatory Assets and Liabilities

The Company has recorded the following regulatory assets and liabilities:

	At September 30	
	2012	2011
	(Thousands)	
Regulatory Assets(1):		
Pension Costs(2) (Note H)	$344,228	$319,906
Post-Retirement Benefit Costs(2) (Note H)	154,415	124,423
Recoverable Future Taxes (Note D)	150,941	144,377
Environmental Site Remediation Costs(2) (Note I)	17,843	20,095
NYPSC Assessment(3)	17,420	15,063
Asset Retirement Obligations(2) (Note B)	26,942	13,860
Unamortized Debt Expense (Note A)	3,997	5,090
Other(4)	15,729	17,639
Total Regulatory Assets	731,515	660,453
Less: Amounts Included in Other Current Assets	(29,726)	(26,589)
Total Long-Term Regulatory Assets	$701,789	$633,864

	At September 30	
	2012	2011
	(Thousands)	
Regulatory Liabilities:		
Cost of Removal Regulatory Liability	$139,611	$135,940
Taxes Refundable to Customers (Note D)	66,392	65,543
Amounts Payable to Customers (See Regulatory Mechanisms in Note A)	19,964	15,519
Off-System Sales and Capacity Release Credits(5)	16,262	7,675
Other(6)	23,041	23,351
Total Regulatory Liabilities	265,270	248,028
Less: Amounts included in Current and Accrued Liabilities	(38,253)	(29,368)
Total Long-Term Regulatory Liabilities	$227,017	$218,660

(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, 2012 and September 30, 2011 since such amounts are expected to be recovered from ratepayers in the next 12 months.

(4) $12,306 and $11,526 are included in Other Current Assets on the Consolidated Balance Sheets at September 30, 2012 and 2011, respectively, since such amounts are expected to be recovered from ratepayers in the next 12 months. $3,423 and $6,113 are included in Other Regulatory Assets on the Consolidated Balance Sheets at September 30, 2012 and 2011, respectively.

(5) Amounts are included in Other Accruals and Current Liabilities on the Consolidated Balance Sheets at September 30, 2012 and September 30, 2011 since such amounts are expected to be passed back to ratepayers in the next 12 months.

(6) $2,027 and $6,174 are included in Other Accruals and Current Liabilities on the Consolidated Balance Sheets at September 30, 2012 and 2011, respectively, since such amounts are expected to be recovered from ratepayers in the next 12 months. $21,014 and $17,177 are included in Other Regulatory Liabilities on the Consolidated Balance Sheets at September 30, 2012 and 2011, 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.

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.

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.

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		
	2012	2011	2010
		(Thousands)	
Current Income Taxes —			
Federal	$ (8)	$ (1,390)	$ 2,074
State	6,412	1,520	4,991
Deferred Income Taxes —			
Federal	111,176	130,434	110,515
State	32,974	33,817	24,164
	150,554	164,381	141,744
Deferred Investment Tax Credit	(581)	(697)	(697)
Total Income Taxes	$149,973	$163,684	$141,047
Presented as Follows:			
Other Income	$ (581)	$ (697)	$ (697)
Income Tax Expense — Continuing Operations	150,554	164,381	137,227
Discontinued Operations —			
Income from Operations	—	—	493
Gain on Disposal	—	—	4,024
Total Income Taxes	$149,973	$163,684	$141,047

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		
	2012	2011	2010
		(Thousands)	
U.S. Income Before Income Taxes	$370,050	$422,086	$366,960
Income Tax Expense, Computed at U.S. Federal Statutory Rate of 35%	$129,518	$147,730	$128,436
Increase (Reduction) in Taxes Resulting from:			
State Income Taxes	25,601	22,969	18,951
Miscellaneous	(5,146)	(7,015)	(6,340)
Total Income Taxes	$149,973	$163,684	$141,047

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

	At September 30	
	2012	2011
	(Thousands)	
Deferred Tax Liabilities:		
Property, Plant and Equipment	$1,333,574	$1,062,255
Pension and Other Post-Retirement Benefit Costs	236,431	217,302
Other	43,294	70,389
Total Deferred Tax Liabilities	1,613,299	1,349,946
Deferred Tax Assets:		
Pension and Other Post-Retirement Benefit Costs	(276,501)	(263,606)
Tax Loss Carryforwards	(198,744)	(71,516)
Other	(83,052)	(74,863)
Total Deferred Tax Assets	(558,297)	(409,985)
Total Net Deferred Income Taxes	$1,055,002	$ 939,961
Presented as Follows:		
Deferred Tax Liability/(Asset) — Current	$ (10,755)	$ (15,423)
Deferred Tax Liability — Non-Current	1,065,757	955,384
Total Net Deferred Income Taxes	$1,055,002	$ 939,961

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. Cumulative tax benefits of $32.7 million and $19.1 million for the periods ending September 30, 2012 and September 30, 2011, respectively, relating to the excess stock-based compensation deductions 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 $66.4 million and $65.5 million at September 30, 2012 and 2011, 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 $150.9 million and $144.4 million at September 30, 2012 and 2011, 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 $47.3 million as of September 30, 2012 and 2011, and regulatory assets of $65.9 million and $60.5 million as of September 30, 2012 and 2011, respectively.

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

	Year Ended September 30		
	2012	2011	2010
	(Thousands)		
Balance at Beginning of Year	$ 7,766	$8,490	$8,721
Additions for Tax Positions Related to Current Year	1,600	80	699
Additions for Tax Positions of Prior Years	2,751	107	45
Reductions for Tax Positions of Prior Years	(947)	(911)	(975)
Balance at End of Year	$11,170	$7,766	$8,490

The Company anticipates that during the next 12 months there will be additional Internal Revenue Service (IRS) guidance relative to its tax method of accounting for certain capitalized costs relating to its utility property and the IRS Appeals process will be resolved (see discussion below). This would result in an elimination of approximately \$7.3 million of unrecognized tax benefits, which would not have a material impact on the effective tax rate. As of September 30, 2012, approximately \$4.9 million 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 recognized interest expense relating to income taxes of \$0.3 million, \$0.3 million and \$0.3 million for fiscal 2012, 2011 and 2010, respectively. The Company has not accrued any penalties during fiscal 2012, 2011 and 2010.

The IRS is currently conducting examinations of the Company for fiscal 2011 and fiscal 2012 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. Local IRS examiners proposed to disallow most of the tax accounting method change recorded by the Company in fiscal 2009 and fiscal 2010. The Company has filed protests for fiscal 2009 and fiscal 2010 with the IRS Appeals Office disputing the local IRS findings.

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, 2012, the Company has a federal net operating loss (NOL) carryover of \$565 million, which expires in varying amounts between 2023 and 2032. Approximately \$23 million of this NOL is subject to certain annual limitations, and \$84 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 \$278 million, \$155 million and \$138 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.

Note E — Capitalization and Short-Term Borrowings

Summary of Changes in Common Stock Equity

	Common Stock		Paid In Capital	Earnings Reinvested in the Business	Accumulated Other Comprehensive Income (Loss)
	Shares	Amount			
	(Thousands, except per share amounts)				
Balance at September 30, 2009	80,500	$80,500	$602,839	$ 948,293	$(42,396)
Net Income Available for Common Stock				225,913	
Dividends Declared on Common Stock ($1.36 Per Share)				(110,944)	
Other Comprehensive Loss, Net of Tax					(2,589)
Share-Based Payment Expense(2)			4,435		
Common Stock Issued Under Stock and Benefit Plans(1)	1,575	1,575	38,345		
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(3)	$(99,020)

(1) Paid in Capital includes tax benefits of $1.0 million for September 30, 2012, tax costs of $1.2 million for September 30, 2011 and tax benefits of $13.2 million for September 30, 2010 associated with the exercise of stock options and/or performance based 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, 2012, $1.2 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

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 2012, the Company issued 155,310 original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan.

During 2012, the Company issued 465,894 original issue shares of common stock as a result of stock option and SARs exercises and 41,525 original issue shares for restricted stock awards (non-vested stock as defined by the current accounting literature for stock-based compensation). 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 2012, 161,021 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 15,755 original issue shares of common stock during 2012.

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 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, 2011	1,758,961	$31.38		
Granted in 2012	—	$ —		
Exercised in 2012	(476,243)	$25.28		
Forfeited in 2012	—	$ —		
Outstanding at September 30, 2012	1,282,718	$33.64	2.65	$26,166
Option shares exercisable at September 30, 2012	1,282,718	$33.64	2.65	$26,166
Option shares available for future grant at September 30, 2012(1)	2,097,214			

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

Transactions involving non-performance based 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, 2011	245,000	$58.79		
Granted in 2012	166,000	$55.09		
Exercised in 2012	—	$ —		
Forfeited in 2012	—	$ —		
Outstanding at September 30, 2012	411,000	$57.30	8.20	$(1,339)
SARs exercisable at September 30, 2012	109,990	$53.56	6.51	$ 53

Transactions involving performance based 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, 2011	1,225,153	$40.85		
Granted in 2012	—	$ —		
Exercised in 2012	(2,000)	$29.88		
Forfeited in 2012	—	$ —		
Canceled in 2012(1)	(6,000)	$58.99		
Outstanding at September 30, 2012	1,217,153	$40.78	6.68	$16,140
SARs exercisable at September 30, 2012	1,039,309	$38.80	6.56	$15,837

(1) Shares were canceled during 2012 due to performance condition not being met.

Restricted Share Awards

Transactions involving restricted shares for all plans are summarized as follows:

	Number of Restricted Share Awards	Weighted Average Fair Value per Award
Restricted Share Awards Outstanding at September 30, 2011	139,250	$53.37
Granted in 2012	41,525	$55.09
Vested in 2012	(18,740)	$59.74
Forfeited in 2012	—	$ —
Restricted Share Awards Outstanding at September 30, 2012	162,035	$53.07

Vesting restrictions for the outstanding shares of non-vested restricted stock at September 30, 2012 will lapse as follows: 2013 — 34,582 shares; 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 restricted stock units for all plans are summarized as follows:

	Number of Restricted Share Awards	Weighted Average Fair Value per Award
Restricted Stock Units Outstanding at September 30, 2011	39,400	$59.20
Granted in 2012	68,450	$47.10
Vested in 2012	—	$ —
Forfeited in 2012	(1,950)	$46.96
Restricted Stock Units Outstanding at September 30, 2012	105,900	$51.61

Vesting restrictions for the outstanding shares of non-vested restricted stock units at September 30, 2012 will lapse as follows: 2014 — 12,932 shares; 2015 — 35,300 shares; 2016 — 35,301 shares; and 2017 — 22,367 shares.

Redeemable Preferred Stock

As of September 30, 2012, 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	
	2012	2011
	(Thousands)	
Medium-Term Notes(1):		
7.4% due March 2023 to June 2025	$ 99,000	$ 249,000
Notes(1):		
4.90% to 8.75% due March 2013 to December 2021	1,300,000	800,000
Total Long-Term Debt	1,399,000	1,049,000
Less Current Portion(2)	250,000	150,000
	$1,149,000	$ 899,000

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

(2) Current Portion of Long-Term Debt at September 30, 2012 consists of $250.0 million of 5.25% notes that mature in March 2013. Current Portion of Long-Term Debt at September 30, 2011 consisted of $150.0 million of 6.70% medium-term notes that matured in November 2011.

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 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.

In addition, the Company has $300.0 million of 6.50% notes that mature in April 2018 and $250.0 million of 8.75% notes that mature in May 2019. 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.

As of September 30, 2012, the aggregate principal amounts of long-term debt maturing during the next five years and thereafter are as follows: $250.0 million in 2013, zero for 2014 through 2017, and $1,149.0 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.

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. 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%. At September 30, 2011, the Company had $40.0 million in outstanding commercial paper, which had a weighted average interest rate of 0.43%.

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, 2012, the Company's debt to capitalization ratio (as calculated under the facility) was .44. The constraints specified in the committed credit facility would have permitted an additional $2.07 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, 2012, the Company would have been permitted to issue up to a maximum of $1.51 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 7.1%) of the Company's long-term debt (as of September 30, 2012) 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, 2012, 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.

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, 2012 and 2011. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

Recurring Fair Value Measures	At Fair Value as of September 30, 2012				
	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total
	(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

Recurring Fair Value Measures	At Fair Value as of September 30, 2011 Level 1	Level 2	Level 3	Netting Adjustments(1)	Total
	(Dollars in thousands)				
Assets:					
Cash Equivalents — Money Market Mutual Funds	$32,444	$ —	$ —	$ —	$ 32,444
Derivative Financial Instruments:					
Commodity Futures Contracts — Gas	4,541	—	—	(4,541)	—
Over the Counter Swaps — Gas	—	75,292	—	(179)	75,113
Over the Counter Swaps — Oil	—	—	10,420	(9,448)	972
Other Investments:					
Balanced Equity Mutual Fund	19,882	—	—	—	19,882
Common Stock — Financial Services Industry	4,478	—	—	—	4,478
Other Common Stock	226	—	—	—	226
Hedging Collateral Deposits	19,701	—	—	—	19,701
Total	$81,272	$75,292	$10,420	$(14,168)	$152,816
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts — Gas	$ 7,833	$ —	$ —	$ (4,541)	$ 3,292
Over the Counter Swaps — Gas	—	179	—	(179)	—
Over the Counter Swaps — Oil	—	—	15,830	(9,448)	6,382
Total	$ 7,833	$ 179	$15,830	$(14,168)	$ 9,674
Total Net Assets/(Liabilities)	$73,439	$75,113	$ (5,410)	$ —	$143,142

(1) Amounts represent the impact of legally-enforceable master netting arrangements that allow the Company to net gain and loss positions held with the same counterparties.

Derivative Financial Instruments

At September 30, 2012 and 2011, the derivative financial instruments reported in Level 1 consist of natural gas NYMEX futures contracts used in the Company's Energy Marketing segment. Hedging collateral deposits of $0.4 million (at September 30, 2012) and $5.5 million (at September 30, 2011), which are associated with these futures contracts, have been reported in Level 1 as well. The derivative financial instruments reported in Level 2 consist of all of the natural gas price swap agreements used in the Company's Exploration and Production and Energy Marketing segments at September 30, 2012 and 2011, and some of the crude oil price swap agreements used in the Company's Exploration and Production segment at September 30, 2012. 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 the majority of the crude oil price swap agreements used in the Company's Exploration and Production segment at September 30, 2012 and all of the crude oil price swap agreements used in the Company's Exploration and Production segment at September 30, 2011. Hedging collateral deposits of $14.2 million associated with these crude oil price swap agreements have been reported in Level 1 at September 30, 2011. The fair value of the Level 3 crude oil price swap agreements is based on an internal, discounted cash flow model that uses both observable (i.e. LIBOR based discount rates) and unobservable inputs (i.e. basis differential information of crude oil trading markets with low trading volume).

The significant unobservable input used in the fair value measurement of the majority 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, 2012, it was assumed that Midway Sunset oil was 110.5% 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 103.2% to 125.0% of NYMEX. If the basis differential between Midway Sunset oil and NYMEX contracts used in the fair value measurement calculation at September 30, 2012 had been 10 percentage points lower, the fair value of the Level 3 crude oil price swap agreements liability would have been approximately $19.4 million lower. If the basis differential between Midway Sunset oil and NYMEX contracts used in the fair value measurement at September 30, 2012 had been 10 percentage points higher, the fair value measurement of the Level 3 crude oil price swap agreements liability would have been approximately $19.4 million higher. 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.

Based on an assessment of the counterparties' credit risk, the fair market value of the price swap agreements reported as Level 2 assets (after netting arrangements) at September 30, 2012 has been reduced by $0.2 million and the fair market value of the price swap agreements reported as Level 2 and Level 3 assets (after netting arrangements) at September 30, 2011 have been reduced by $2.0 million. Based on an assessment of the Company's credit risk, the fair market value of the price swap agreements reported as Level 2 and Level 3 liabilities (after netting arrangements) at September 30, 2012 has been reduced by $1.2 million and the fair market value of the price swap agreements reported as Level 3 liabilities (after netting arrangements) has not been reduced at September 30, 2011. These credit reserves were determined by applying default probabilities to the anticipated cash flows that the Company is either expecting from its counterparties or expecting to pay to its counterparties.

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, 2012 and September 30, 2011, respectively. For the years ended September 30, 2012 and September 30, 2011, 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, 2011	(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.

Fair Value Measurements Using Unobservable Inputs (Level 3)

	October 1, 2010	Total Gains/Losses: (Gains)/Losses Realized and Included in Earnings	Total Gains/Losses: Gains/(Losses) Unrealized and Included in Other Comprehensive Income (Loss)	Transfer In/(Out) of Level 3	September 30, 2011
			(Dollars in thousands)		
Derivative Financial Instruments(2)	$(16,483)	$41,354(1)	$(30,281)	$—	$(5,410)

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the year ended September 30, 2011.

(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: 2012 Carrying Amount	2012 Fair Value	2011 Carrying Amount	2011 Fair Value
		(Thousands)		
Long-Term Debt	$1,399,000	$1,623,847	$1,049,000	$1,198,585

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 contracts amounted to $57.0 million and $54.8 million at September 30, 2012 and 2011, respectively. The fair value of the equity mutual fund was $24.8 million and $19.9 million at September 30, 2012 and 2011, respectively. The gross unrealized gain on this equity mutual fund was $2.6 million at September 30, 2012. The gross unrealized loss on this equity mutual fund was $0.7 million at September 30, 2011. The fair value of the stock of an insurance company was $4.8 million and $4.5 million at September 30, 2012 and 2011, respectively. The gross unrealized gain on this stock was $2.3 million and $2.1 million at September 30, 2012 and 2011, 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 or has used derivative instruments to manage commodity price risk in the Exploration and Production, Energy Marketing and Pipeline and Storage segments. 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, 2012 and September 30, 2011. All of the derivative financial instruments reported on those line items related to commodity contracts as discussed in the paragraph above.

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, 2012, 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	133.5 Bcf (all short positions)
Crude Oil	2,316,000 Bbls (all short positions)

As of September 30, 2012, 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	5.7 Bcf (all short positions (forecasted storage withdrawals))

As of September 30, 2012, the Company's Exploration and Production segment had $0.9 million ($0.5 million after tax) of net unrealized hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that $21.9 million ($12.7 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. It is expected that unrealized losses will be reclassified into the Consolidated Statement of Income in subsequent periods as the expected sales of the underlying commodities occur.

As of September 30, 2012, the Company's Energy Marketing segment had $2.8 million ($1.7 million after tax) of net hedging losses 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.

As of September 30, 2012, the Company's Pipeline and Storage segment had $0.7 million ($0.4 million after tax) of net hedging losses 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, Energy Marketing and Pipeline and Storage segments.

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Year Ended September 30, 2012 and 2011 (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,	
	2012	2011		2012	2011		2012	2011
Commodity Contracts — Exploration & Production segment	$(11,776)	$24,713	Operating Revenue	$54,777	$ 6,367	Not Applicable	$—	$—
Commodity Contracts — Energy Marketing segment	$ 4,725	$ 5,015	Purchased Gas	$10,439	$ 8,608	Not Applicable	$—	$—
Commodity Contracts — Pipeline & Storage segment(1)	$ (197)	$ 510	Operating Revenue	$ 475	$ 510	Not Applicable	$—	$—
Total	$ (7,248)	$30,238		$65,691	$15,485		$—	$—

(1) There were no open hedging positions at September 30, 2012 or 2011.

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 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, 2012, the Company's Energy Marketing segment had fair value hedges covering approximately 10.2 Bcf (8.7 Bcf of fixed price sales commitments (all long positions), 1.1 Bcf of fixed price purchase commitments (all short positions) and 0.4 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.

Consolidated Statement of Income	Gain/(Loss) on Derivative	Gain/(Loss) on Commitment
Operating Revenues	$ 8,021,910	$(8,021,910)
Purchased Gas	$(1,235,817)	$ 1,235,817

Derivatives in Fair Value Hedging Relationships – Energy Marketing segment	Location of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income	Amount of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income for the Year Ended September 30, 2012
		(In thousands)
Commodity Contracts — Hedge of fixed price sales commitments of natural gas	Operating Revenues	$ 8,022
Commodity Contracts — Hedge of fixed price purchase commitments of natural gas	Purchased Gas	(1,261)
Commodity Contracts — Hedge of natural gas held in storage	Purchased Gas	25
		$ 6,786

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 twelve counterparties of which four are in a net gain position. On average, the Company had $6.4 million of credit exposure per counterparty in a gain position at September 30, 2012. The maximum credit exposure per counterparty in a gain position at September 30, 2012 was $11.0 million. As of September 30, 2012, 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, 2012, ten of the twelve 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 current liability were larger) and/or the Company's credit rating declined, then additional hedging collateral deposits may be required. At September 30, 2012, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $14.0 million according to the Company's internal model (discussed in Note F — Fair Value Measurements). At September 30, 2012, the fair market value of the derivative financial instrument liabilities with a credit-risk related contingency feature was $23.9 million according to the Company's internal model (discussed in Note F — Fair Value Measurements). For its over-the-counter crude oil swap agreements, which were in a liability position, the Company was not required to post any hedging collateral deposits at September 30, 2012.

For its exchange traded futures contracts which are in a liability position, the Company had posted $0.4 million in hedging collateral deposits as of September 30, 2012. 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) that covers approximately half of the full-time employees of the Company. 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 $0.9 million, $0.7 million and $0.6 million for the years ended September 30, 2012, 2011 and 2010, 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 $4.3 million, $4.3 million, and $4.2 million for the years ended September 30, 2012, 2011 and 2010, respectively.

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

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

The expected return on 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.

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 2012, 2011 and 2010.

	Retirement Plan			Other Post-Retirement Benefits		
	Year Ended September 30			Year Ended September 30		
	2012	2011	2010	2012	2011	2010
	(Thousands)					
Change in Benefit Obligation						
Benefit Obligation at Beginning of Period	$ 949,777	$ 924,493	$ 831,496	$ 485,452	$ 472,407	$ 467,295
Service Cost	14,202	14,772	12,997	4,016	4,276	4,298
Interest Cost	41,526	42,676	44,308	21,315	21,884	25,017
Plan Participants' Contributions	—	—	—	1,956	1,963	1,644
Retiree Drug Subsidy Receipts	—	—	—	1,528	1,532	1,354
Amendments(1)	—	(1,764)	—	—	(7,187)	—
Actuarial (Gain) Loss	120,338	21,395	85,831	71,708	15,071	(3,635)
Benefits Paid	(55,099)	(51,795)	(50,139)	(24,712)	(24,494)	(23,566)
Benefit Obligation at End of Period	$1,070,744	$ 949,777	$ 924,493	$ 561,263	$ 485,452	$ 472,407
Change in Plan Assets						
Fair Value of Assets at Beginning of Period	$ 601,719	$ 597,549	$ 563,881	$ 351,990	$ 353,269	$ 319,022
Actual Return on Plan Assets	111,034	2,412	61,625	63,552	(4,094)	30,478
Employer Contributions	44,022	53,553	22,182	21,348	25,346	25,691
Plan Participants' Contributions	—	—	—	1,956	1,963	1,644
Benefits Paid	(55,099)	(51,795)	(50,139)	(24,712)	(24,494)	(23,566)
Fair Value of Assets at End of Period	$ 701,676	$ 601,719	$ 597,549	$ 414,134	$ 351,990	$ 353,269
Net Amount Recognized at End of Period (Funded Status)	$ (369,068)	$(348,058)	$(326,944)	$(147,129)	$(133,462)	$(119,138)
Amounts Recognized in the Balance Sheets Consist of:						
Non-Current Liabilities	$ (369,068)	$(348,058)	$(326,944)	$(147,129)	$(133,462)	$(119,138)
Accumulated Benefit Obligation	$ 986,223	$ 874,595	$ 843,526	N/A	N/A	N/A
Weighted Average Assumptions Used to Determine Benefit Obligation at September 30						
Discount Rate	3.50%	4.50%	4.75%	3.50%	4.50%	4.75%
Rate of Compensation Increase	4.75%	4.75%	4.75%	4.75%	4.75%	4.75%

	Retirement Plan			Other Post-Retirement Benefits		
	Year Ended September 30			Year Ended September 30		
	2012	2011	2010	2012	2011	2010
	(Thousands)					
Components of Net Periodic Benefit Cost						
Service Cost	$ 14,202	$ 14,772	$ 12,997	$ 4,016	$ 4,276	$ 4,298
Interest Cost	41,526	42,676	44,308	21,315	21,884	25,017
Expected Return on Plan Assets	(59,701)	(59,103)	(58,342)	(28,971)	(29,165)	(26,334)
Amortization of Prior Service Cost	269	588	655	(2,138)	(1,710)	(1,710)
Amortization of Transition Amount	—	—	—	10	541	541
Recognition of Actuarial Loss(2)	39,615	34,873	21,641	24,057	23,794	25,881
Net Amortization and Deferral for Regulatory Purposes	(6,900)	(2,311)	(30)	6,162	10,490	351
Net Periodic Benefit Cost	$ 29,011	$ 31,495	$ 21,229	$ 24,451	$ 30,110	$ 28,044
Weighted Average Assumptions Used to Determine Net Periodic Benefit Cost at September 30						
Discount Rate	4.50%	4.75%	5.50%	4.50%	4.75%	5.50%
Expected Return on Plan Assets	8.25%	8.25%	8.25%	8.25%	8.25%	8.25%
Rate of Compensation Increase	4.75%	4.75%	5.00%	4.75%	4.75%	5.00%

(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 \$9.1 million, \$8.6 million and \$7.4 million in 2012, 2011 and 2010, respectively. The accumulated benefit obligations for the plans were \$54.5 million, \$46.0 million and \$41.8 million at September 30, 2012, 2011 and 2010, respectively. The projected benefit obligations for the plans were \$88.5 million,

$79.2 million and $73.9 million at September 30, 2012, 2011 and 2010, 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 2.50%, 3.75% and 4.25% as of September 30, 2012, 2011 and 2010, respectively and a weighted average rate of compensation increase of 7.75%, 8.0% and 8.0% as of September 30, 2012, 2011 and 2010, respectively.

The cumulative amounts recognized in accumulated other comprehensive income (loss), regulatory assets, and regulatory liabilities through fiscal 2012, the changes in such amounts during 2012, as well as the amounts expected to be recognized in net periodic benefit cost in fiscal 2013 are presented in the table below:

	Retirement Plan	Other Post-Retirement Benefits	Non-Qualified Benefit Plans
		(Thousands)	
Amounts Recognized in Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities(1)			
Net Actuarial Loss	$(458,125)	$(195,305)	$(40,770)
Transition Obligation	—	(8)	—
Prior Service (Cost) Credit	(1,304)	11,217	—
Net Amount Recognized	$(459,429)	$(184,096)	$(40,770)
Changes to Accumulated Other Comprehensive Income (Loss), Regulatory Assets and Regulatory Liabilities Recognized During Fiscal 2012(1)			
Increase in Actuarial Loss, excluding amortization(2)	$ (69,005)	$ (37,134)	$ (9,559)
Change due to Amortization of Actuarial Loss	39,615	24,057	4,363
Reduction in Transition Obligation	—	10	—
Prior Service (Cost) Credit	269	(2,138)	—
Net Change	$ (29,121)	$ (15,205)	$ (5,196)
Amounts Expected to be Recognized in Net Periodic Benefit Cost in the Next Fiscal Year(1)			
Net Actuarial Loss	$ (52,776)	$ (20,892)	$ (5,280)
Transition Obligation	—	(8)	—
Prior Service (Cost) Credit	(238)	2,138	—
Net Amount Expected to be Recognized	$ (53,014)	$ (18,762)	$ (5,280)

(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, 2012, the Company recorded a $32.2 million increase to Other Regulatory Assets in the Company's Utility and Pipeline and Storage segments and a $17.3 million (pre-tax) increase to Accumulated Other Comprehensive Loss.

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. In 2012, other actuarial experience increased the projected benefit obligation for the Retirement Plan by $1.6 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 effect of the discount rate change for the Retirement Plan in 2010 was to increase the projected benefit obligation of the Retirement Plan by $75.1 million.

The Company made cash contributions totaling $44.0 million to the Retirement Plan during the year ended September 30, 2012. The Company expects that the annual contribution to the Retirement Plan in 2013 will be in the range of $30.0 million to $45.0 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 2013 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 currently in the process of 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: $55.9 million in 2013; $56.5 million in 2014; $57.3 million in 2015; $58.5 million in 2016; $59.6 million in 2017; and $315.2 million in the five years thereafter.

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 effect of the discount rate change in 2010 was to increase the other post-retirement benefit obligation by $39.4 million. Other actuarial experience decreased the other post-retirement benefit obligation in 2010 by $43.1 million, primarily attributable to updated pharmaceutical drug rebate experience as well as updated claim costs assumptions based on experience.

The Medicare Prescription Drug, Improvement, and Modernization Act of 2003 provides for a prescription drug benefit under Medicare (Medicare Part D), as well as a federal subsidy to sponsors of retiree health care benefit plans that provide a benefit that is at least actuarially equivalent to Medicare Part D. 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
2013	$ 26,559	$ (1,828)
2014	$ 27,852	$ (2,021)
2015	$ 29,154	$ (2,220)
2016	$ 30,506	$ (2,420)
2017	$ 31,859	$ (2,606)
2018 through 2022	$175,145	$(15,964)

	2012	2011	2010
Rate of Increase for Pre Age 65 Participants	7.46%(1)	7.64%(1)	7.82%(1)
Rate of Increase for Post Age 65 Participants	6.84%(1)	6.89%(1)	6.95%(1)
Annual Rate of Increase in the Per Capita Cost of Covered Prescription Drug Benefits	8.08%(1)	8.39%(1)	8.69%(1)
Annual Rate of Increase in the Per Capita Medicare Part B Reimbursement	6.84%(1)	6.89%(1)	6.95%(1)
Annual Rate of Increase in the Per Capita Medicare Part D Subsidy	7.13%(1)	7.30%(1)	7.60%(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, 2012 would increase by $69.7 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 2012 by $3.4 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, 2012 would decrease by $58.1 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 2012 by $2.8 million.

The Company made cash contributions totaling $21.2 million to its VEBA trusts and 401(h) accounts during the year ended September 30, 2012. 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, 2012. The Company expects that the annual contribution to its VEBA trusts and 401(h) accounts in 2013 will be in the range of $15.0 million to $20.0 million.

Investment Valuation

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

The inputs or methodologies used for valuing securities are not necessarily an indication of the risk associated with investing in those securities. Below is a listing of the major categories of plan assets held as of September 30, 2012 and 2011, 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, 2012	Level 1	Level 2	Level 3
Retirement Plan Investments				
Domestic Equities(1)	$358,679	$231,978	$126,701	$ —
International Equities(2)	96,451	2,090	94,361	—
Domestic Fixed Income(3)	165,130	70,730	94,400	—
International Fixed Income(4)	65,835	1,941	63,894	—
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			

	Total Fair Value Amounts at September 30, 2011	Level 1	Level 2	Level 3
Retirement Plan Investments				
Domestic Equities(1)	$313,193	$215,524	$ 97,669	$ —
International Equities(2)	79,732	11,163	68,569	—
Domestic Fixed Income(3)	146,587	77,657	68,930	—
International Fixed Income(4)	43,153	887	42,266	—
Hedge Fund Investments	39,296	—	—	39,296
Real Estate	6,443	—	—	6,443
Cash and Cash Equivalents	10,629	—	10,629	—
Total Retirement Plan Investments	639,033	305,231	288,063	45,739
401(h) Investments	(37,176)	(17,744)	(16,773)	(2,659)
Total Retirement Plan Investments (excluding 401(h) Investments)	$601,857	$287,487	$271,290	$43,080
Miscellaneous Accruals, Interest Receivables, and Non-Interest Cash	(138)			
Total Retirement Plan Assets	$601,719			

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

(4) International Fixed Income securities includes mostly collective trust funds and exchange traded funds.

	Total Fair Value Amounts at September 30, 2012	Level 1	Level 2	Level 3
Other Post-Retirement Benefit Assets held in VEBA Trusts				
Collective Trust Funds — Domestic Equities	$179,059	$ —	$179,059	$ —
Collective Trust Funds — International Equities	66,590	—	66,590	—
Exchange Traded Funds — Fixed Income	107,597	107,597	—	—
Real Estate	1,305	—	—	1,305
Cash Held in Collective Trust Funds	16,397	—	16,397	—
Total VEBA Trust Investments	370,948	107,597	262,046	1,305
401(h) Investments	43,311	17,818	22,813	2,680
Total Investments (including 401(h) Investments)	$414,259	$125,415	$284,859	$3,985
Miscellaneous Accruals (Including Current and Deferred Taxes, Claims Incurred But Not Reported, Administrative)	(125)			
Total Other Post-Retirement Benefit Assets	$414,134			

	Total Fair Value Amounts at September 30, 2011	Level 1	Level 2	Level 3
Other Post-Retirement Benefit Assets held in VEBA Trusts				
Collective Trust Funds — Domestic Equities	$148,451	$ —	$148,451	$ —
Collective Trust Funds — International Equities	55,411	—	55,411	—
Exchange Traded Funds — Fixed Income	91,214	91,214	—	—
Real Estate	1,561	—	—	1,561
Cash Held in Collective Trust Funds	12,890	—	12,890	—
Total VEBA Trust Investments	309,527	91,214	216,752	1,561
401(h) Investments	37,176	17,744	16,773	2,659
Total Investments (including 401(h) Investments)	$346,703	$108,958	$233,525	$4,220
Miscellaneous Accruals (Including Current and Deferred Taxes, Claims Incurred But Not Reported, Administrative)	5,287			
Total Other Post-Retirement Benefit Assets	$351,990			

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

The following tables provide a reconciliation of the beginning and ending balances of the Retirement Plan and other post-retirement benefit assets measured at fair value on a recurring basis where the determination of fair value includes significant unobservable inputs (Level 3). Note: For the year ended September 30, 2012, there was approximately $13.0 million transferred from Level 1 to Level 2, while for the year ended September 30, 2011, there were no significant transfers in or out of Level 1 or Level 2. In addition, as shown in the following tables, there were no transfers in or out of Level 3.

	Retirement Plan Level 3 Assets (Thousands)					
	Equity Convertible Securities	Hedge Funds	Limited Partnerships	Real Estate	Excluding 401(h) Investments	Total
Balance at September 30, 2010	$ 337	$ —	$ 245	$6,148	$ (367)	$ 6,363
Realized Gains/(Losses)	53	—	(4,846)	20	278	(4,495)
Unrealized Gains/(Losses)	(36)	(789)	4,853	159	(268)	3,919
Purchases, Sales, Issuances, and Settlements (Net)	(354)	40,085	(252)	116	(2,302)	37,293
Balance at September 30, 2011	—	39,296	—	6,443	(2,659)	43,080
Realized Gains/(Losses)	—	—	—	60	(4)	56
Unrealized Gains/(Losses)	—	660	—	(362)	(15)	283
Purchases, Sales, Issuances, and Settlements (Net)	—	—	—	29	(2)	27
Balance at September 30, 2012	$ —	$39,956	$ —	$6,170	$(2,680)	$43,446

	Other Post-Retirement Benefit Level 3 Assets (Thousands)		
	VEBA Trust Investments		
	Real Estate	Including 401(h) Investments	Other Post-Retirement Benefit Investments
Balance at September 30, 2010	$ 3,824	$ 367	$ 4,191
Realized Gains/(Losses)	—	(278)	(278)
Unrealized Gains/(Losses)	(2,263)	268	(1,995)
Purchases, Sales, Issuances, and Settlements (Net)	—	2,302	2,302
Balance at September 30, 2011	1,561	2,659	4,220
Realized Gains/(Losses)	—	4	4
Unrealized Gains/(Losses)	(256)	15	(241)
Purchases, Sales, Issuances, and Settlements (Net)	—	2	2
Balance at September 30, 2012	$ 1,305	$2,680	$ 3,985

The Company's assumption regarding the expected long-term rate of return on plan assets is 8.0%, effective for fiscal 2013. The return assumption 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.

The long-term investment objective of the Retirement Plan trust, the VEBA trusts and the 401(h) accounts is to achieve the target total return in accordance with the Company's risk tolerance. Assets are diversified utilizing a mix of equities, fixed income and other securities (including real estate). The target allocation for the Retirement Plan is 55-70% equity securities, 25-40% fixed income securities and 5-20% other. The target allocation for the VEBA trusts (including 401(h) accounts) is 60-75% equity securities, 25-40% fixed income securities and 0-15% other. Risk tolerance is established through consideration of plan liabilities, plan funded status and corporate financial condition. The assets of the Retirement Plan trusts, VEBA trusts and the 401(h) accounts have no significant concentrations of risk in any one country (other than the United States), industry or entity.

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

The discount rate which is used to present value the future benefit payment obligations of the Retirement Plan and the Company's other post-retirement benefits is 3.50% as of September 30, 2012. The discount rate which is used to present value the future benefit payment obligations of the Non-Qualified benefit plans is 2.50% as of September 30, 2012. The Company utilizes a yield curve 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.

Note I — Commitments and Contingencies

Environmental Matters

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and to comply with regulatory 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, 2012, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites will be in the range of \$15.4 million to \$19.6 million. The minimum estimated liability of \$15.4 million has been recorded in Other Deferred Credits on the Consolidated Balance Sheet at September 30, 2012. The Company expects to recover its environmental clean-up costs through rate recovery over a period of approximately 10 years. Other than as discussed below, the Company is currently not aware of any material exposure to environmental liabilities. However, changes in environmental laws and regulations, new information or other factors could adversely impact the Company.

(i) Former Manufactured Gas Plant Sites

The Company has incurred investigation and/or clean-up costs at several former manufactured gas plant sites in New York and Pennsylvania. The Company continues to be responsible for future ongoing monitoring and long-term maintenance at two sites.

The Company has agreed with the NYDEC to remediate another former manufactured gas plant site located in New York. In February 2009, the Company received approval from the NYDEC of a Remedial Design Work Plan (RDWP) for this site. In October 2010, the Company submitted a RDWP addendum to conduct additional Preliminary Design Investigation field activities necessary to design a successful remediation. An estimated minimum liability for remediation of this site of \$14.0 million has been recorded.

(ii) Other

In November 2010, the NYDEC notified the Company of its potential liability with respect to a remedial action at a former industrial site in New York. Along with the Company, notifications were sent to the City of Buffalo and the New York State Thruway Authority. Estimated clean-up costs associated with this site have not been completed and the Company cannot estimate its liability, if any, regarding remediation of this site at this time. In July 2011, the Company agreed to perform a limited scope of work at this site, which is pending.

Other

The Company, in its Utility segment, Energy Marketing segment, and Exploration and Production segment, has entered into contractual commitments in the ordinary course of business, including commitments to purchase gas, transportation, and storage service to meet customer gas supply needs. The majority of these contracts expire within the next five years. The future gas purchase, transportation and storage contract commitments during the next five years and thereafter are as follows: $278.1 million in 2013, $68.1 million in 2014, $64.1 million in 2015, $60.2 million in 2016, $32.3 million in 2017 and $66.6 million thereafter. Gas prices within the gas purchase contracts are variable based on NYMEX prices adjusted for basis. In the Utility segment, these costs are subject to state commission review, and are being recovered in customer rates. Management believes that, to the extent any stranded pipeline costs are generated by the unbundling of services in the Utility segment's service territory, such costs will be recoverable from customers.

The Company has entered into leases for the use of compressors, drilling rigs, buildings, meters and other items. These leases are accounted for as operating leases. The future lease commitments during the next five years and thereafter are as follows: $38.7 million in 2013, $37.0 million in 2014, $13.2 million in 2015, $5.8 million in 2016, $5.7 million in 2017, and $8.5 million thereafter.

The Company, in its Pipeline and Storage segment and All Other category, has entered into several contractual commitments associated with various pipeline and gathering system expansion projects. As of September 30, 2012, the future contractual commitments related to the expansion projects are $40.7 million in 2013. There are no contractual commitments extending beyond 2013.

The Company, in its Exploration and Production segment, has entered into contractual obligations associated with hydraulic fracturing and fuel. The future contract commitments during the next two years are as follows: $60.7 million in 2013 and $11.4 million in 2014.

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

Note J — Discontinued Operations

On September 1, 2010, the Company sold its landfill gas operations in the states of Ohio, Michigan, Kentucky, Missouri, Maryland and Indiana. Those operations consisted of short distance landfill gas pipeline companies engaged in the purchase, sale and transportation of landfill gas. The Company's landfill gas operations were maintained under the Company's wholly-owned subsidiary, Horizon LFG. The Company received approximately $38.0 million of proceeds from the sale. The sale resulted in the recognition of a gain of approximately $6.3 million, net of tax, during the fourth quarter of 2010. The decision to sell was based on progressing the Company's strategy of divesting its smaller, non-core assets in order to focus on its core businesses, including the development of the Marcellus Shale and the construction of key pipeline infrastructure projects throughout the Appalachian region. As a result of the decision to sell the landfill gas operations, the Company began presenting these operations as discontinued operations during the fourth quarter of 2010.

The following is selected financial information of the discontinued operations for the sale of the Company's landfill gas operations:

	Year Ended September 30, 2010
	(Thousands)
Operating Revenues	$9,919
Operating Expenses	8,933
Operating Income	986
Other Income	4
Interest Income	2
Interest Expense	29
Income before Income Taxes	963
Income Tax Expense	493
Income from Discontinued Operations	470
Gain on Disposal, Net of Taxes of $4,024	6,310
Income from Discontinued Operations	$6,780

Note K — Business Segment Information

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

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

The Pipeline and Storage segment operations are regulated by the FERC for both Supply Corporation and Empire. Supply Corporation transports and stores natural gas for utilities (including Distribution Corporation), natural gas marketers (including NFR), exploration and production companies (including Seneca) and pipeline companies in the northeastern United States markets. Empire transports natural gas to major industrial companies, utilities (including Distribution Corporation) and power producers in New York State.

The Exploration and Production segment, through Seneca, is engaged in exploration for, and development and purchase of, natural gas and oil reserves in California, the Appalachian region of the United States and Kansas. The Company completed the sale of its off-shore oil and natural gas properties in April 2011 as a result of the segment's increasing emphasis on the Marcellus Shale play within the Appalachian region. Seneca's production is, for the most part, sold to purchasers located in the vicinity of its wells. In November 2010, the Company acquired oil and gas properties in the Covington Township area of Tioga County, Pennsylvania from EOG Resources, Inc. for approximately $24.1 million. In addition, the Company acquired two tracts of leasehold acreage in March 2010 for approximately $71.8 million. These tracts, consisting of approximately 18,000 net acres in Tioga and Potter Counties in Pennsylvania, are geographically similar to the Company's existing Marcellus Shale acreage in the area.

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

The data presented in the tables below reflect financial information for the segments and reconciliations to consolidated amounts. The accounting policies of the segments are the same as those described in Note A — Summary of Significant Accounting Policies. Sales of products or services between segments are billed at regulated rates or at market rates, as applicable. The Company evaluates segment performance based on income before discontinued operations, extraordinary items and cumulative effects of changes in accounting (when applicable). When these items are not applicable, the Company evaluates performance based on net income.

	Year Ended September 30, 2012							
	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)							
Revenue from External Customers(1)	$ 704,518	$ 172,312	$ 558,180	$186,579	$1,621,589	$ 4,307	$ 957	$1,626,853
Intersegment Revenues	$ 14,604	$ 86,963	$ —	$ 1,425	$ 102,992	$ 16,771	$(119,763)	$ —
Interest Income	$ 2,765	$ 199	$ 1,493	$ 188	$ 4,645	$ 175	$ (1,131)	$ 3,689
Interest Expense	$ 33,181	$ 25,603	$ 29,243	$ 41	$ 88,068	$ 1,738	$ (3,566)	$ 86,240
Depreciation, Depletion and Amortization	$ 42,757	$ 38,182	$ 187,624	$ 90	$ 268,653	$ 2,091	$ 786	$ 271,530
Income Tax Expense (Benefit)	$ 29,110	$ 37,655	$ 79,050	$ 1,933	$ 147,748	$ 4,335	$ (1,529)	$ 150,554
Segment Profit: Net Income (Loss)	$ 58,590	$ 60,527	$ 96,498	$ 4,169	$ 219,784	$ 6,868	$ (6,575)	$ 220,077
Expenditures for Additions to Long-Lived Assets	$ 58,284	$ 144,167	$ 693,810	$ 770	$ 897,031	$ 80,017	$ 346	$ 977,394

	At September 30, 2012							
	(Thousands)							
Segment Assets	$2,070,413	$1,243,862	$2,367,485	$ 61,968	$5,743,728	$209,934	$ (18,520)	$5,935,142

	Year Ended September 30, 2011							
	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)							
Revenue from External Customers(1)	$ 835,853	$ 134,071	$ 519,035	$284,546	$1,773,505	$ 4,401	$ 936	$1,778,842
Intersegment Revenues	$ 16,642	$ 81,037	$ —	$ 420	$ 98,099	$ 10,017	$(108,116)	$ —
Interest Income	$ 2,049	$ 324	$ (27)	$ 104	$ 2,450	$ 247	$ 219	$ 2,916
Interest Expense	$ 34,440	$ 25,737	$ 17,402	$ 20	$ 77,599	$ 2,173	$ (1,651)	$ 78,121
Depreciation, Depletion and Amortization	$ 40,808	$ 37,266	$ 146,806	$ 47	$ 224,927	$ 840	$ 760	$ 226,527
Income Tax Expense (Benefit)	$ 33,325	$ 19,854	$ 89,034	$ 4,489	$ 146,702	$ 18,961	$ (1,282)	$ 164,381
Gain on Sale of Unconsolidated Subsidiaries	$ —	$ —	$ —	$ —	$ —	$ 50,879(2)	$ —	$ 50,879
Segment Profit: Net Income (Loss)	$ 63,228	$ 31,515	$ 124,189	$ 8,801	$ 227,733	$ 38,502	$ (7,833)	$ 258,402
Expenditures for Additions to Long-Lived Assets	$ 58,398	$ 129,206	$ 648,815	$ 460	$ 836,879	$ 17,022	$ 285	$ 854,186

	At September 30, 2011							
	(Thousands)							
Segment Assets	$2,001,546	$1,112,494	$1,885,014	$ 71,138	$5,070,192	$166,730	$ (15,838)	$5,221,084

	Year Ended September 30, 2010							
	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
	(Thousands)							
Revenue from External Customers(1)	$ 804,466	$ 138,905	$ 438,028	$344,802	$1,726,201	$ 33,428	$ 874	$1,760,503
Intersegment Revenues	$ 15,324	$ 79,978	$ —	$ —	$ 95,302	$ 2,315	$(97,617)	$ —
Interest Income	$ 2,144	$ 199	$ 980	$ 44	$ 3,367	$ 137	$ 225	$ 3,729
Interest Expense	$ 35,831	$ 26,328	$ 30,853	$ 27	$ 93,039	$ 2,152	$ (1,245)	$ 93,946
Depreciation, Depletion and Amortization	$ 40,370	$ 35,930	$ 106,182	$ 42	$ 182,524	$ 7,907	$ 768	$ 191,199
Income Tax Expense (Benefit)	$ 31,858	$ 22,634	$ 78,875	$ 4,806	$ 138,173	$ 464	$ (1,410)	$ 137,227
Segment Profit: Income (Loss) from Continuing Operations	$ 62,473	$ 36,703	$ 112,531	$ 8,816	$ 220,523	$ 3,396	$ (4,786)	$ 219,133
Expenditures for Additions to Long-Lived Assets from Continuing Operations	$ 57,973	$ 37,894	$ 398,174	$ 407	$ 494,448	$ 6,694	$ 210	$ 501,352
	At September 30, 2010							
	(Thousands)							
Segment Assets	$2,027,101	$1,080,772	$1,539,705	$ 69,561	$4,717,139	$198,706	$131,209	$5,047,054

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

(2) In February 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.

Geographic Information

	At September 30		
	2012	2011	2010
		(Thousands)	
Long-Lived Assets:			
United States	$5,579,566	$4,809,183	$4,238,253

Note L — Quarterly Financial Data (unaudited)

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

Quarter Ended	Operating Revenues	Operating Income	Net Income Available for Common Stock	Earnings per Common Share Basic	Earnings per Common Share Diluted
	(Thousands, except per common share amounts)				
2012					
9/30/2012	$313,261	$107,265	$ 48,802(1)	$0.59	$0.58
6/30/2012	$328,861	$ 90,293	$ 43,184	$0.52	$0.52
3/31/2012	$552,308	$132,097	$ 67,392(2)	$0.81	$0.81
12/31/2011	$432,423	$118,394	$ 60,699	$0.73	$0.73
2011					
9/30/2011	$286,034	$ 75,191	$ 37,356	$0.45	$0.45
6/30/2011	$380,979	$ 94,805	$ 46,891	$0.57	$0.56
3/31/2011	$660,881	$153,756	$115,611(3)	$1.40	$1.38
12/31/2010	$450,948	$117,410	$ 58,544	$0.71	$0.70

(1) Includes $12.8 million of income associated with the elimination of Supply Corporation's post-retirement regulatory liability as specified in Supply Corporation's rate case settlement.

(2) Includes a $4.0 million accrual of a natural gas impact fee related to wells drilled prior to 2012 that was first imposed by Pennsylvania in 2012. This fee was recorded in the Exploration and Production segment.

(3) Includes a $31.4 million after tax gain on the sale of the Company's 50% equity method investments in Seneca Energy and Model City.

Note M — Market for Common Stock and Related Shareholder Matters (unaudited)

At September 30, 2012, there were 13,800 registered shareholders of Company common stock. The common stock is listed and traded on the New York Stock Exchange. Information related to restrictions on the payment of dividends can be found in Note E — Capitalization and Short-Term Borrowings. The quarterly price ranges (based on intra-day prices) and quarterly dividends declared for the fiscal years ended September 30, 2012 and 2011, are shown below:

	Price Range		
Quarter Ended	High	Low	Dividends Declared
2012			
9/30/2012	$54.99	$45.56	$.365
6/30/2012	$48.68	$41.57	$.365
3/31/2012	$56.97	$46.85	$.355
12/31/2011	$64.19	$44.51	$.355
2011			
9/30/2011	$75.98	$48.67	$.355
6/30/2011	$75.75	$66.39	$.355
3/31/2011	$74.00	$65.80	$.345
12/31/2010	$66.52	$51.66	$.345

Note N — Supplementary Information for Oil and Gas Producing Activities (unaudited)

As of September 30, 2010, the Company adopted the revisions to authoritative guidance related to oil and gas exploration and production activities that aligned the reserve estimation and disclosure requirements with the requirements of the SEC Modernization of Oil and Gas Reporting rule, which the Company also adopted. The SEC rules require companies to value their year-end reserves using an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve month period prior to the end of the reporting period.

The following supplementary information is presented in accordance with the authoritative guidance regarding disclosures about oil and gas producing activities and related SEC accounting rules. All monetary amounts are expressed in U.S. dollars. As discussed in Note A, the Company completed the sale of its off-shore oil and natural gas properties in the Gulf of Mexico in April 2011. With the completion of this sale, the Company no longer has any off-shore oil and gas properties.

Capitalized Costs Relating to Oil and Gas Producing Activities

	At September 30	
	2012	2011
	(Thousands)	
Proved Properties(1)	$2,789,181	$2,010,662
Unproved Properties	146,084	226,276
	2,935,265	2,236,938
Less — Accumulated Depreciation, Depletion and Amortization	681,798	499,671
	$2,253,467	$1,737,267

(1) Includes asset retirement costs of $43.1 million and $32.7 million at September 30, 2012 and 2011, respectively.

Costs related to unproved properties are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized. Although the timing of the ultimate evaluation or disposition of the unproved properties cannot be determined, the Company expects the majority of its acquisition costs associated with unproved properties to be transferred into the amortization base by 2020. It expects the majority of its development and exploration costs associated with unproved properties to be transferred into the amortization base by 2014 or 2015. Following is a summary of costs excluded from amortization at September 30, 2012:

	Total as of September 30, 2012	Year Costs Incurred			
		2012	2011	2010	Prior
		(Thousands)			
Acquisition Costs	$ 87,280	$ 6,195	$ —	$69,206	$11,879
Development Costs	21,947	15,225	6,722	—	—
Exploration Costs	33,891	33,891	—	—	—
Capitalized Interest	2,966	2,966	—	—	—
	$146,084	$58,277	$6,722	$69,206	$11,879

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

	Year Ended September 30		
	2012	2011	2010
		(Thousands)	
United States			
Property Acquisition Costs:			
Proved	$ 13,095	$ 28,838	$ 790
Unproved	13,867	20,012	80,221
Exploration Costs(1)	84,624	62,651	75,155
Development Costs(2)	576,397	531,372	234,094
Asset Retirement Costs	10,344	12,087	3,901
	$698,327	$654,960	$394,161

(1) Amounts for 2012, 2011 and 2010 include capitalized interest of $1.0 million, $0.8 million and $0.2 million, respectively.

(2) Amounts for 2012, 2011 and 2010 include capitalized interest of $2.0 million, $0.7 million and $0.9 million, respectively.

For the years ended September 30, 2012, 2011 and 2010, the Company spent $216.6 million, $199.2 million and $28.9 million, respectively, developing proved undeveloped reserves.

Results of Operations for Producing Activities

	Year Ended September 30		
	2012	2011	2010
	(Thousands, except per Mcfe amounts)		
United States			
Operating Revenues:			
Natural Gas (includes revenues from sales to affiliates of $1, $23 and $253, respectively)	$ 181,544	$ 223,648	$ 152,163
Oil, Condensate and Other Liquids	307,018	273,952	233,569
Total Operating Revenues(1)	488,562	497,600	385,732
Production/Lifting Costs	83,361	73,250	61,398
Franchise/Ad Valorem Taxes	23,620	12,179	10,592
Accretion Expense	3,084	3,668	5,444
Depreciation, Depletion and Amortization ($2.19, $2.12 and $2.10 per Mcfe of production)	182,759	143,372	104,092
Income Tax Expense	81,904	110,117	83,946
Results of Operations for Producing Activities (excluding corporate overheads and interest charges)	$113,834	$155,014	$120,260

(1) Exclusive of hedging gains and losses. See further discussion in Note G — Financial Instruments.

Reserve Quantity Information

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

The Company's Vice President of Reservoir Engineering is the primary technical person responsible for overseeing the Company's reserve estimation process and engaging and overseeing the third party reserve audit. His qualifications include a Bachelor of Science Degree in Petroleum Engineering and over 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 nine 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 that determines the reserves. The Vice President of Reservoir Engineering reviews and approves all new reserve assignments and significant reserve revisions. Access to the Reserve database is restricted. Significant changes to the reserve report are reviewed by senior management on a quarterly basis. Periodically, the Company's internal audit department assesses the design of these controls and performs testing to determine the effectiveness of such controls.

All of the Company's reserve estimates are audited annually by Netherland, Sewell and Associates, Inc. (NSAI). Since 1961, NSAI has evaluated gas and oil properties and independently certified petroleum reserve quantities in the United States and internationally under the Texas Board of Professional Engineers Registration No. F-002699. The primary technical persons (employed by NSAI) that are responsible for leading the audit include a professional engineer registered with the State of Texas (with 14 years of experience in petroleum engineering and consulting at NSAI since 2004) and a professional geoscientist registered in the State of Texas (with 15 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, 2012 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 include data from the Company's wells, published documents, and state data-sites, and 2D and 3D seismic data. These were used to confirm continuity of the formation.

	Gas MMcf			
	U. S.			
	Appalachian Region	West Coast Region	Gulf Coast Region	Total Company
Proved Developed and Undeveloped Reserves:				
September 30, 2009	149,828	72,959	26,167	248,954
Extensions and Discoveries	189,979(1)	269	2,881	193,129
Revisions of Previous Estimates	7,677	2,315	6,683	16,675
Production	(16,222)(2)	(3,819)	(10,304)	(30,345)
September 30, 2010	331,262	71,724	25,427	428,413
Extensions and Discoveries	249,047(1)	195	158	249,400
Revisions of Previous Estimates	24,486	526	1,373	26,385
Production	(42,979)(2)	(3,447)	(4,041)	(50,467)
Purchases of Minerals in Place	44,790	—	—	44,790
Sales of Minerals in Place	—	(682)	(22,917)	(23,599)
September 30, 2011	606,606	68,316	—	674,922
Extensions and Discoveries	435,460(1)	638	—	436,098
Revisions of Previous Estimates	(53,992)	(2,463)	—	(56,455)
Production	(62,663)(2)	(3,468)	—	(66,131)
September 30, 2012	925,411	63,023	—	988,434
Proved Developed Reserves:				
September 30, 2009	120,579	67,603	18,051	206,233
September 30, 2010	210,817	66,178	19,293	296,288
September 30, 2011	350,458	63,965	—	414,423
September 30, 2012	544,560	59,923	—	604,483
Proved Undeveloped Reserves:				
September 30, 2009	29,249	5,356	8,116	42,721
September 30, 2010	120,445	5,546	6,134	132,125
September 30, 2011	256,148	4,351	—	260,499
September 30, 2012	380,851	3,100	—	383,951

(1) Extensions and discoveries include 182 Bcf (during 2010), 249 Bcf (during 2011) and 435 Bcf (during 2012), of Marcellus Shale gas in the Appalachian Region.

(2) Production includes 7,180 MMcf (during 2010), 35,356 MMcf (during 2011) and 55,812 MMcf (during 2012), from Marcellus Shale fields (which exceed 15% of total reserves).

	Oil Mbbl			
	U. S.			
	Appalachian Region	West Coast Region	Gulf Coast Region	Total Company
Proved Developed and Undeveloped Reserves:				
September 30, 2009	311	44,824	1,452	46,587
Extensions and Discoveries	4	828	222	1,054
Revisions of Previous Estimates	2	484	332	818
Production	(49)	(2,669)(1)	(502)	(3,220)
September 30, 2010	268	43,467	1,504	45,239
Extensions and Discoveries	10	756	1	767
Revisions of Previous Estimates	46	1,909	(339)	1,616
Production	(45)	(2,628)	(187)	(2,860)
Sales of Minerals in Place	—	(438)	(979)	(1,417)
September 30, 2011	279	43,066	—	43,345
Extensions and Discoveries	28	1,229	—	1,257
Revisions of Previous Estimates	35	1,095	—	1,130
Production	(36)	(2,834)	—	(2,870)
September 30, 2012	306	42,556	—	42,862
Proved Developed Reserves:				
September 30, 2009	285	37,711	1,194	39,190
September 30, 2010	263	36,353	1,066	37,682
September 30, 2011	274	37,306	—	37,580
September 30, 2012	306	38,138	—	38,444
Proved Undeveloped Reserves:				
September 30, 2009	26	7,113	258	7,397
September 30, 2010	5	7,114	438	7,557
September 30, 2011	5	5,760	—	5,765
September 30, 2012	—	4,418	—	4,418

(1) The Midway Sunset North fields (which exceeded 15% of total reserves at September 30, 2010) contributed 1,543 Mbbls of production during 2010. As of September 30, 2012 and 2011, the Midway Sunset North fields were below 15% of total reserves.

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 Company's proved undeveloped (PUD) reserves increased from 177 Bcfe at September 30, 2010 to 295 Bcfe at September 30, 2011. PUD reserves in the Marcellus Shale increased from 110 Bcf at September 30, 2010 to 253 Bcf at September 30, 2011. There was a material increase in PUD reserves at September 30, 2011 and 2010 as a result of Marcellus Shale reserve additions. The Company's total PUD reserves are 32% of total proved reserves at September 30, 2011, up from 25% of total proved reserves at September 30, 2010.

The increase in PUD reserves in 2012 of 115 Bcfe is 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 increase in PUD reserves in 2011 of 118 Bcfe is a result of 212 Bcfe in new PUD reserve additions (209 Bcfe from the Marcellus Shale), offset by 83 Bcfe in PUD conversions to proved developed reserves, 10 Bcfe from sales of minerals in place and 2 Bcfe in downward PUD revisions of previous estimates. The downward revisions were primarily from the removal of proved locations in the Upper Devonian play. These locations are unlikely to be developed within a 5-year timeframe due to the Company's focus on the Marcellus Shale and the better economic results there.

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. In 2013, the Company estimates that it will invest approximately $160 million to develop its PUD reserves. 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 represents 33% of the PUD reserves booked at September 30, 2011. The Company invested $146 million during the year ended September 30, 2011 to convert 83 Bcfe of September 30, 2010 PUD reserves to proved developed reserves. This represented 47% of the PUD reserves booked at September 30, 2010. The Company invested an additional $53 million during the year ended September 30, 2011 to develop the additional working interests in Covington area PUD wells that were acquired from EOG Resources during fiscal 2011.

At September 30, 2012, 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 or country level. All of the Company's proved reserves are in the United States. At the field level, only at the North Lost Hills Field in Kern County, California, does the Company have a material concentration of PUD reserves that have been on the books for more than five years. The Company has reduced the concentration of PUD reserves in this field from 44% of total field level proved reserves at September 30, 2007 to 16% of total field level proved reserves at September 30, 2012. The PUD reserves in this field represent less than 1% of the Company's proved reserves at the corporate level. The economics of this project remain strong and the steam-flood project here is performing well. Drilling of the remaining proved undeveloped locations in this field is scheduled over the next three years as steam generation capacity is increased and the steam-flood here matures.

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

The Company cautions that the following presentation of the standardized measure of discounted future net cash flows is intended to be neither a measure of the fair market value of the Company's oil and gas properties, nor an estimate of the present value of actual future cash flows to be obtained as a result of their development and production. It is based upon subjective estimates of proved reserves only and attributes no value to categories of reserves other than proved reserves, such as probable or possible reserves, or to unproved acreage. Furthermore, as a result of the SEC's final rule on Modernization of Oil and Gas Reporting (effective fiscal 2010), it is based on the unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period and costs adjusted only for existing contractual changes. It assumes an arbitrary discount rate of 10%. Thus, it gives no effect to future price and cost changes certain to occur under widely fluctuating political and economic conditions.

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

	Year Ended September 30		
	2012	2011	2010
		(Thousands)	
United States			
Future Cash Inflows	$7,373,129	$7,180,320	$5,273,605
Less:			
Future Production Costs	1,919,530	1,555,603	1,347,855
Future Development Costs	619,573	636,745	445,413
Future Income Tax Expense at Applicable Statutory Rate	1,812,055	1,834,778	1,186,567
Future Net Cash Flows	3,021,971	3,153,194	2,293,770
Less:			
10% Annual Discount for Estimated Timing of Cash Flows	1,552,180	1,629,037	1,120,182
Standardized Measure of Discounted Future Net Cash Flows	$1,469,791	$1,524,157	$1,173,588

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

	Year Ended September 30		
	2012	2011	2010
		(Thousands)	
United States			
Standardized Measure of Discounted Future Net Cash Flows at Beginning of Year	$1,524,157	$1,173,588	$ 875,977
Sales, Net of Production Costs	(381,581)	(412,172)	(313,742)
Net Changes in Prices, Net of Production Costs	(385,019)	404,445	176,530
Purchases of Minerals in Place	—	52,697	—
Sales of Minerals in Place	—	(73,633)	—
Extensions and Discoveries	224,474	218,140	329,555
Changes in Estimated Future Development Costs	29,627	(85,191)	(17,353)
Previously Estimated Development Costs Incurred	252,967	168,275	47,539
Net Change in Income Taxes at Applicable Statutory Rate	(19,280)	(249,773)	(85,703)
Revisions of Previous Quantity Estimates	103,472	124,545	46,246
Accretion of Discount and Other	120,974	203,236	114,539
Standardized Measure of Discounted Future Net Cash Flows at End of Year	$1,469,791	$1,524,157	$1,173,588

Schedule II — Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Additions Charged to Costs and Expenses	Additions Charged to Other Accounts(1)	Deductions(2)	Balance at End of Period
Year Ended September 30, 2012					
Allowance for Uncollectible Accounts	$31,039	$ 9,183	$1,946	$11,851	$30,317
Year Ended September 30, 2011					
Allowance for Uncollectible Accounts	$30,961	$11,974	$2,484	$14,380	$31,039
Year Ended September 30, 2010					
Allowance for Uncollectible Accounts	$38,334	$15,422	$2,268	$25,063	$30,961

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

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

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

None.

Item 9A *Controls and Procedures*

Evaluation of Disclosure Controls and Procedures

The term "disclosure controls and procedures" is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to the company's management, including its principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. The Company's management, including the Chief Executive Officer and Principal Financial Officer, evaluated the effectiveness of the Company's disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, the Company's Chief Executive Officer and Principal Financial Officer concluded that the Company's disclosure controls and procedures were effective as of September 30, 2012.

Management's Annual Report on Internal Control over Financial Reporting

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

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of September 30, 2012. In making this assessment, management used the framework and criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control — Integrated Framework*. Based on this assessment, management concluded that the Company maintained effective internal control over financial reporting as of September 30, 2012.

PricewaterhouseCoopers LLP, the independent registered public accounting firm that audited the Company's consolidated financial statements included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of September 30, 2012. The report appears in Part II, Item 8 of this Annual Report on Form 10-K.

Changes in Internal Control over Financial Reporting

There were no changes in the Company's internal control over financial reporting that occurred during the quarter ended September 30, 2012 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B *Other Information*

None.

PART III

Item 10 *Directors, Executive Officers and Corporate Governance*

The information concerning directors will be set forth in the definitive Proxy Statement under the headings entitled "Nominees for Election as Directors for Three-Year Terms to Expire in 2016," "Directors Whose Terms Expire in 2015," "Directors Whose Terms Expire in 2014," and "Section 16(a) Beneficial Ownership Reporting Compliance" and is incorporated herein by reference. The information concerning corporate governance will be set forth in the definitive Proxy Statement under the heading entitled "Meetings of the Board of Directors and Standing Committees" and is incorporated herein by reference. Information concerning the Company's executive officers can be found in Part I, Item 1, of this report.

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

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

Item 11 *Executive Compensation*

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

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

Equity Compensation Plan Information

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

Security Ownership and Changes in Control

(a) Security Ownership of Certain Beneficial Owners

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

(b) Security Ownership of Management

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

(c) Changes in Control

None.

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

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

Item 14 ***Principal Accountant Fees and Services***

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

PART IV

Item 15 ***Exhibits and Financial Statement Schedules***

(a)1. Financial Statements

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

(a)2. Financial Statement Schedules

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

(a)3. Exhibits

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

Exhibit Number	Description of Exhibits
3(i)	Articles of Incorporation:
3.1	Restated Certificate of Incorporation of National Fuel Gas Company dated September 21, 1998; Certificate of Amendment of Restated Certificate of Incorporation dated March 14, 2005
3(ii)	By-Laws:
•	National Fuel Gas Company By-Laws as amended March 10, 2011 (Exhibit 3.1, Form 8-K dated March 14, 2011)
4	Instruments Defining the Rights of Security Holders, Including Indentures:
•	Indenture, dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 2(b) in File No. 2-51796)
•	Third Supplemental Indenture, dated as of December 1, 1982, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(a)(4) in File No. 33-49401)
•	Eleventh Supplemental Indenture, dated as of May 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(b), Form 8-K dated February 14, 1992)
•	Twelfth Supplemental Indenture, dated as of June 1, 1992, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(c), Form 8-K dated June 18, 1992)
•	Thirteenth Supplemental Indenture, dated as of March 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4(a)(14) in File No. 33-49401)
•	Fourteenth Supplemental Indenture, dated as of July 1, 1993, to Indenture dated as of October 15, 1974, between the Company and The Bank of New York Mellon (formerly Irving Trust Company) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1993)
•	Indenture dated as of October 1, 1999, between the Company and The Bank of New York Mellon (formerly The Bank of New York) (Exhibit 4.1, Form 10-K for fiscal year ended September 30, 1999)
•	Officers Certificate establishing 5.25% Notes due 2013, dated February 18, 2003 (Exhibit 4, Form 10-Q for the quarterly period ended March 31, 2003)
•	Officer's Certificate establishing 6.50% Notes due 2018, dated April 11, 2008 (Exhibit 4.1, Form 10-Q for the quarterly period ended June 30, 2008)
•	Officer's Certificate establishing 8.75% Notes due 2019, dated April 6, 2009 (Exhibit 4.4, Form 8-K dated April 6, 2009)
•	Officer's Certificate establishing 4.90% Notes due 2021, dated December 1, 2011 (Exhibit 4.4, Form 8-K dated December 1, 2011)

Exhibit Number	Description of Exhibits
•	Amended and Restated Rights Agreement, dated as of December 4, 2008, between the Company and The Bank of New York Mellon (formerly The Bank of New York), as rights agent (Exhibit 4.1, Form 8-K dated December 4, 2008)
4.1	Letter of Appointment of Wells Fargo Bank, National Association, as Successor Rights Agent, dated July 18, 2012
10	Material Contracts:
•	Amended and Restated Credit Agreement, dated as of January 6, 2012, among the Company, the Lenders Party Thereto, and JPMorgan Chase Bank, National Association, as Administrative Agent (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2012)
•	Form of Indemnification Agreement, dated September 2006, between the Company and each Director (Exhibit 10.1, Form 8-K dated September 18, 2006)
•	Resolutions adopted by the National Fuel Gas Company Board of Directors on February 21, 2008 regarding director stock ownership guidelines (Exhibit 10.5, Form 10-Q for the quarterly period ended March 31, 2008)
	Management Contracts and Compensatory Plans and Arrangements:
•	Form of Amended and Restated Employment Continuation and Noncompetition Agreement among the Company, a subsidiary of the Company and each of David P. Bauer, Karen M. Camiolo, Carl M. Carlotti, Anna Marie Cellino, Paula M. Ciprich, Donna L. DeCarolis, John R. Pustulka, James D. Ramsdell, David F. Smith and Ronald J. Tanski (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2008)
•	Form of Amended and Restated Employment Continuation and Noncompetition Agreement among the Company, Seneca Resources Corporation and Matthew D. Cabell (Exhibit 10.2, Form 10-K for the fiscal year ended September 30, 2008)
•	Letter Agreement between the Company and Matthew D. Cabell, dated November 17, 2006 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2006)
•	Description of September 17, 2009 restricted stock award (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2009)
•	Description of post-employment medical and prescription drug benefits (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 2009)
•	National Fuel Gas Company 1997 Award and Option Plan, as amended and restated as of July 23, 2007 (Exhibit 10.4, Form 10-Q for the quarterly period ended March 31, 2008)
•	Form of Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.1, Form 8-K dated March 28, 2005)
•	Form of Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.1, Form 8-K dated May 16, 2006)
•	Form of Restricted Stock Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2006)
•	Form of Stock Option Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2006)
•	Form of Stock Appreciation Right Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2008)

Exhibit Number	Description of Exhibits
•	Form of Stock Appreciation Right Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2008)
•	Form of Stock Appreciation Right Award Notice under National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2011)
•	Form of Restricted Stock Award Notice under the National Fuel Gas Company 1997 Award and Option Plan (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2010)
•	Administrative Rules with Respect to At Risk Awards under the 1997 Award and Option Plan amended and restated as of September 8, 2005 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 2005)
•	National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.1, Form 8-K dated March 17, 2010)
•	Form of Stock Appreciation Right Award Notice under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2010)
•	Form of Stock Appreciation Right Award Notice under the National Fuel Gas Company 2010 Equity Compensation Plan (Exhibit 10.4, Form 10-Q for the quarterly period ended December 31, 2010)
•	Amended and Restated National Fuel Gas Company 2007 Annual At Risk Compensation Incentive Program (Exhibit 10.3, Form 10-K for the fiscal year ended September 30, 2008)
•	Description of performance goals under the Amended and Restated National Fuel Gas Company 2007 Annual At Risk Compensation Incentive Program and the National Fuel Gas Company Executive Annual Cash Incentive Program (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 2010)
•	Description of performance goals under the Amended and Restated National Fuel Gas Company 2007 Annual At Risk Compensation Incentive Program and the National Fuel Gas Company Executive Annual Cash Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2011)
•	National Fuel Gas Company 2012 Annual At Risk Compensation Incentive Plan (Exhibit 10.2, Form 10-Q for the quarterly period ended March 31, 2012)
•	National Fuel Gas Company Executive Annual Cash Incentive Program (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2009)
•	Administrative Rules of the Compensation Committee of the Board of Directors of National Fuel Gas Company, as amended and restated effective December 7, 2011 (Exhibit 10.3, Form 10-Q for the quarterly period ended December 31, 2011)
•	National Fuel Gas Company Deferred Compensation Plan, as amended and restated through May 1, 1994 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 1994)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated September 27, 1995 (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1995)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated September 19, 1996 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1996)
•	National Fuel Gas Company Deferred Compensation Plan, as amended and restated through March 20, 1997 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1997)

Exhibit Number	Description of Exhibits
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 16, 1997 (Exhibit 10.4, Form 10-K for fiscal year ended September 30, 1997)
•	Amendment No. 2 to the National Fuel Gas Company Deferred Compensation Plan, dated March 13, 1998 (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 1998)
•	Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated February 18, 1999 (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 1999)
•	Amendment to National Fuel Gas Company Deferred Compensation Plan, dated June 15, 2001 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 2001)
•	Amendment to the National Fuel Gas Company Deferred Compensation Plan, dated October 21, 2005 (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 2005)
•	Form of Letter Regarding Deferred Compensation Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.6, Form 10-K for fiscal year ended September 30, 2005)
•	National Fuel Gas Company Tophat Plan, effective March 20, 1997 (Exhibit 10, Form 10-Q for the quarterly period ended June 30, 1997)
•	Amendment No. 1 to National Fuel Gas Company Tophat Plan, dated April 6, 1998 (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 1998)
•	Amendment No. 2 to National Fuel Gas Company Tophat Plan, dated December 10, 1998 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 1998)
•	Form of Letter Regarding Tophat Plan and Internal Revenue Code Section 409A, dated July 12, 2005 (Exhibit 10.7, Form 10-K for fiscal year ended September 30, 2005)
•	National Fuel Gas Company Tophat Plan, Amended and Restated December 7, 2005 (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2005)
•	National Fuel Gas Company Tophat Plan, as amended September 20, 2007 (Exhibit 10.3, Form 10-K for the fiscal year ended September 30, 2007)
•	Amended and Restated Split Dollar Insurance and Death Benefit Agreement, dated September 17, 1997 between the Company and Philip C. Ackerman (Exhibit 10.5, Form 10-K for fiscal year ended September 30, 1997)
•	Amendment Number 1 to Amended and Restated Split Dollar Insurance and Death Benefit Agreement by and between the Company and Philip C. Ackerman, dated March 23, 1999 (Exhibit 10.3, Form 10-K for fiscal year ended September 30, 1999)
•	Split Dollar Insurance and Death Benefit Agreement, dated September 15, 1997, between the Company and David F. Smith (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1999)
•	Amendment Number 1 to Split Dollar Insurance and Death Benefit Agreement by and between the Company and David F. Smith, dated March 29, 1999 (Exhibit 10.14, Form 10-K for fiscal year ended September 30, 1999)
•	Life Insurance Premium Agreement, dated September 17, 2009, between the Company and David F. Smith (Exhibit 10.1, Form 8-K dated September 23, 2009)
•	National Fuel Gas Company Parameters for Executive Life Insurance Plan (Exhibit 10.1, Form 10-K for fiscal year ended September 30, 2004)
•	National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan as amended and restated through November 1, 1995 (Exhibit 10.10, Form 10-K for fiscal year ended September 30, 1995)

Exhibit Number	Description of Exhibits
•	Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated September 18, 1997 (Exhibit 10.9, Form 10-K for fiscal year ended September 30, 1997)
•	Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated December 10, 1998 (Exhibit 10.2, Form 10-Q for the quarterly period ended December 31, 1998)
•	Amendments to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, effective September 16, 1999 (Exhibit 10.15, Form 10-K for fiscal year ended September 30, 1999)
•	Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, effective September 5, 2001 (Exhibit 10.4, Form 10-K/A for fiscal year ended September 30, 2001)
•	National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of January 1, 2007 (Exhibit 10.5, Form 10-Q for the quarterly period ended December 31, 2006)
•	National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of September 20, 2007 (Exhibit 10.4, Form 10-K for the fiscal year ended September 30, 2007)
•	National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, Amended and Restated as of September 24, 2008 (Exhibit 10.5, Form 10-K for the fiscal year ended September 30, 2008)
•	Amendment to National Fuel Gas Company and Participating Subsidiaries Executive Retirement Plan, dated June 1, 2010 (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2010)
•	National Fuel Gas Company and Participating Subsidiaries 1996 Executive Retirement Plan Trust Agreement (II), dated May 10, 1996 (Exhibit 10.13, Form 10-K for fiscal year ended September 30, 1996)
•	National Fuel Gas Company Participating Subsidiaries Executive Retirement Plan 2003 Trust Agreement(I), dated September 1, 2003 (Exhibit 10.2, Form 10-K for fiscal year ended September 30, 2004)
•	National Fuel Gas Company Performance Incentive Program (Exhibit 10.1, Form 8-K dated June 3, 2005)
•	Description of long-term performance incentives for the period October 1, 2009 to September 30, 2012 under the National Fuel Gas Company Performance Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2009)
•	Description of long-term performance incentives for the period October 1, 2010 to September 30, 2013 under the National Fuel Gas Company Performance Incentive Program (Exhibit 10.1, Form 10-Q for the quarterly period ended December 31, 2010)
•	National Fuel Gas Company 2012 Performance Incentive Program (Exhibit 10.3, Form 10-Q for the quarterly period ended March 31, 2012)
•	Description of long-term performance incentives for the period October 1, 2011 to September 30, 2014 under the National Fuel Gas Company 2012 Performance Incentive Program (Item 5.02, Form 8-K dated March 13, 2012)
•	National Fuel Gas Company 2009 Non-Employee Director Equity Compensation Plan (Exhibit 10.1, Form 10-Q for the quarterly period ended March 31, 2009)

Exhibit Number	Description of Exhibits
•	Description of assignment of interests in certain life insurance policies (Exhibit 10.1, Form 10-Q for the quarterly period ended June 30, 2006)
•	Description of agreement between the Company and Philip C. Ackerman regarding death benefit (Exhibit 10.3, Form 10-Q for the quarterly period ended June 30, 2006)
•	Agreement, dated September 24, 2006, between the Company and Philip C. Ackerman regarding death benefit (Exhibit 10.1, Form 10-K for the fiscal year ended September 30, 2006)
12	Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the fiscal years ended September 30, 2008 through 2012
21	Subsidiaries of the Registrant
23	Consents of Experts:
23.1	Consent of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Corporation
23.2	Consent of Independent Registered Public Accounting Firm
31	Rule 13a-14(a)/15d-14(a) Certifications:
31.1	Written statements of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act
31.2	Written statements of Principal Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act
32••	Certification furnished pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
99	Additional Exhibits:
99.1	Report of Netherland, Sewell & Associates, Inc. regarding Seneca Resources Corporation
99.2	Company Maps
101	Interactive data files submitted pursuant to Regulation S-T: (i) the Consolidated Statements of Income and Earnings Reinvested in the Business for the years ended September 30, 2012, 2011 and 2010, (ii) the Consolidated Balance Sheets at September 30, 2012 and September 30, 2011, (iii) the Consolidated Statements of Cash Flows for the years ended September 30, 2012, 2011 and 2010, (iv) the Consolidated Statements of Comprehensive Income for the years ended September 30, 2012, 2011 and 2010 and (v) the Notes to Consolidated Financial Statements.

• Incorporated herein by reference as indicated.

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

•• In accordance with Item 601(b)(32)(ii) of Regulation S-K and SEC Release Nos. 33-8238 and 34-47986, Final Rule: Management's Reports on Internal Control Over Financial Reporting and Certification of Disclosure in Exchange Act Periodic Reports, the material contained in Exhibit 32 is "furnished" and not deemed "filed" with the SEC and is not to be incorporated by reference into any filing of the Registrant under the Securities Act of 1933 or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language contained in such filing, except to the extent that the Registrant specifically incorporates it by reference.

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

National Fuel Gas Company
(Registrant)

By /s/ D. F. Smith
D. F. Smith
Chairman of the Board and Chief Executive Officer

Date: November 21, 2012

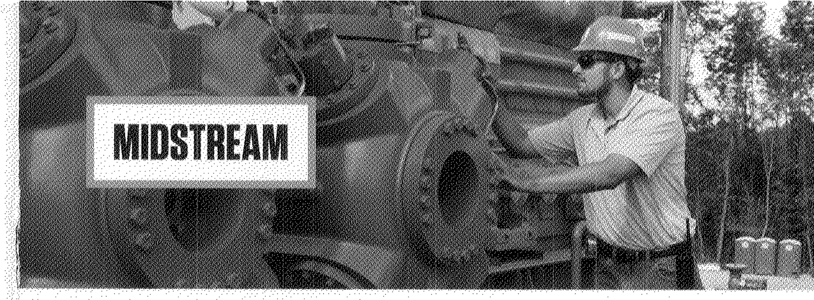
Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	
/s/ D. F. Smith D. F. Smith	Chairman of the Board, Chief Executive Officer and Director	Date: November 21, 2012
/s/ P. C. Ackerman P. C. Ackerman	Director	Date: November 21, 2012
/s/ R. T. Brady R. T. Brady	Director	Date: November 21, 2012
/s/ D. C. Carroll D. C. Carroll	Director	Date: November 21, 2012
/s/ R. D. Cash R. D. Cash	Director	Date: November 21, 2012
/s/ S. E. Ewing S. E. Ewing	Director	Date: November 21, 2012
/s/ R. E. Kidder R. E. Kidder	Director	Date: November 21, 2012
/s/ C. G. Matthews C. G. Matthews	Director	Date: November 21, 2012
/s/ R. G. Reiten R. G. Reiten	Director	Date: November 21, 2012
/s/ F. V. Salerno F. V. Salerno	Director	Date: November 21, 2012
/s/ D. P. Bauer D. P. Bauer	Treasurer and Principal Financial Officer	Date: November 21, 2012
/s/ K. M. Camiolo K. M. Camiolo	Controller and Principal Accounting Officer	Date: November 21, 2012

FUELED BY TALENT • DRIVEN BY VALUE

National Fuel Gas Company

SUMMARY ANNUAL REPORT 2012



MIDSTREAM

PIPELINE & STORAGE

National Fuel Gas Supply Corporation and Empire Pipeline, Inc. provide natural gas transportation and storage services through an integrated system of 2,806 miles of pipeline and 31 underground storage fields.

2012 HIGHLIGHTS:

Operating Revenues:
$259.3 million[1]

Operating Income:
$120.4 million[2]

Net Income:
$60.5 million

Capital Expenditures:
$144.2 million

Total Assets:
$1.244 billion

System Throughput:
371.1 Bcf

- Commenced construction of the Line N 2012 Expansion Project, which moves 163,000 Dth per day of Marcellus production, and placed it fully in service November 2012.
- Started building facilities for the Northern Access Expansion Project, designed to move 320,000 Dth per day of Marcellus production to TransCanada Pipeline at the Canadian Border. The project commenced service November 2012.

2013 OUTLOOK:

- Continue to aggressively pursue new projects, focusing primarily on serving Marcellus and Utica producers in Pennsylvania and Ohio.
- Maintain progress with ongoing efforts to upgrade transmission pipeline and storage assets to ensure safe and reliable natural gas delivery.

GATHERING & PROCESSING

National Fuel Gas Midstream Corporation's primary business is to build, own and operate natural gas processing and pipeline gathering facilities in the Appalachian region.

2012 HIGHLIGHTS:

Operating Revenues:
$17.5 million[1]

Operating Income:
$13.1 million[2]

Net Income:
$6.9 million[3]

Capital Expenditures:
$80.0 million[4]

Total Assets:
$116.8 million[5]

Gathering Volumes:
44.3 Bcf

- Completed initial construction and initiated flow on the 466,000 Mcf per day Trout Run Gathering System and its interconnection with the Transco Pipeline in Lycoming County, Pa., during May 2012, allowing Marcellus production to be transported to major markets.

2013 OUTLOOK:

- Continue to add facilities to both the Trout Run and Covington gathering systems to facilitate the transportation of additional volumes.
- Evaluate potential expansion opportunities for new projects to serve both Seneca Resources and third party producers in the Marcellus and Utica shales.

DOWNSTREAM

UTILITY

National Fuel Gas Distribution Corporation sells or transports natural gas to customers through a local distribution system located in western New York and northwestern Pennsylvania.

2012 HIGHLIGHTS:

Operating Revenues:
$719.1 million[1]

Operating Income:
$117.2 million[2]

Net Income:
$58.6 million

Capital Expenditures:
$58.3 million

Total Assets:
$2.070 billion

System Throughput:
125.1 Bcf

- More than 75% of capital expenditures are allocated to system safety, maintenance and enhancements.
- Assisted qualifying customers in receiving $51 million in HEAP and LIHEAP funding in New York and Pennsylvania.
- Received regulatory approval to extend a successful energy conservation program through 2015.

2013 OUTLOOK:

- Continue to modernize the local distribution system and further promote natural gas as the safe, reliable, clean and economic fuel choice for homes, businesses and vehicles.
- Address the current challenge of providing continuous natural gas service to payment-troubled, low-income customers through enhanced outreach and targeted assistance programs.
- Initiate a multi-year program to upgrade the Customer Information System.

ENERGY MARKETING

National Fuel Resources, Inc. sells competitively priced natural gas to industrial, wholesale, commercial, public authority and residential customers primarily in New York and Pennsylvania.

2012 HIGHLIGHTS:

Operating Revenues:
$188.0 million[1]

Operating Income:
$5.9 million[2]

Net Income:
$4.2 million

Total Assets:
$62.0 million

Total Sales Volume:
45.8 Bcf

- Successfully expanded residential customer base in Pennsylvania.

2013 OUTLOOK:

- Continue customer growth within current markets.
- Maintain high levels of customer satisfaction and retention.
- Implement new customer billing and accounting software to support evolving needs of the business.

National Fuel Gas Company is an integrated, diversified energy company with four financial reporting segments: Exploration and Production, Pipeline and Storage, Utility, and Energy Marketing.

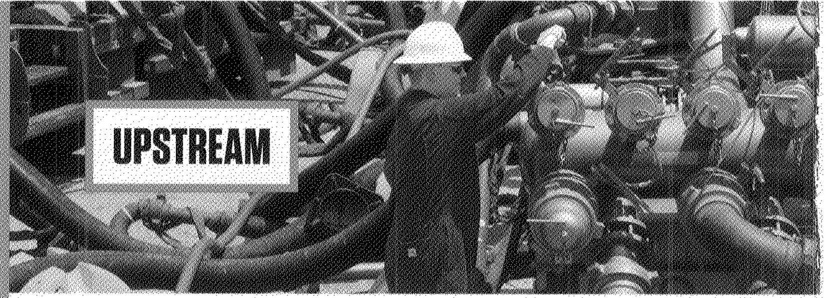
National Fuel's **Upstream** operations are carried out by the Exploration and Production segment through Seneca Resources Corporation, a natural gas and crude oil producer focused on developing its resources in California and within its extensive Appalachian acreage position. The Company's **Midstream** operations are administered by the interstate pipeline, gathering and storage subsidiaries, including National Fuel Gas Supply Corporation, Empire Pipeline, Inc. and National Fuel Gas Midstream Corporation. These subsidiaries develop and operate pipeline and related facilities to serve Appalachian producers and downstream shippers. The Utility and Energy Marketing segments, operated by National Fuel Gas Distribution Corporation and National Fuel Resources, Inc., perform National Fuel's **Downstream** activities and provide natural gas retail services to customers in New York and Pennsylvania.

PHOTO CAPTIONS

Upstream: *Andrew Shepherd, an employee of Seneca Resources Corporation, monitors a Marcellus Shale well completion in Lycoming County, Pa.*

Midstream: *National Fuel Gas Supply Corporation's Josh Corey inspects new facilities being constructed at the Wales, N.Y. Compressor Station.*

Downstream: *Cathy Martorana of National Fuel Gas Distribution Corporation oversees customer operations in the New York Consumer Response Center, ensuring excellent customer service.*



EXPLORATION & PRODUCTION

Seneca Resources Corporation explores for, develops and produces natural gas and crude oil reserves in Appalachia, California and Kansas. Most of Seneca's investment activity is in the Marcellus Shale in Pennsylvania, where the company controls 775,000 net prospective acres.

2012 HIGHLIGHTS:

Operating Revenues:
$558.2 million[1]

Operating Income:
$203.3 million[2]

Net Income:
$96.5 million

Capital Expenditures:
$693.8 million

Total Assets:
$2.367 billion

Total Annual Production:
83.4 Bcfe

- Total natural gas and crude oil proved reserves increased 33% from the prior year, reaching 1.246 Tcfe at September 30, 2012.
- Seneca's three-year average finding and development costs were $1.87 per Mcfe, a decrease of 11% as compared to the prior three-year period ended September 30, 2011.
- Crude oil production in Seneca's West Division grew 8% compared to the prior year.
- Marcellus Shale production increased 58% from the prior year, reaching 55.8 Bcfe in 2012.

2013 OUTLOOK:

- Produce 95 to 107 Bcfe of natural gas and crude oil, representing a 21% increase at the midpoint when compared to the prior year.
- Increase the focus on Seneca's crude oil activities, spending approximately $80 to $110 million on projects within its expanding California operations, as well as its newly acquired acreage in the Mississippian Lime play in Kansas.
- Continue ongoing delineation efforts in the Marcellus and Utica shales across a broad section of Seneca's Pennsylvania acreage position.

Index

Bcf *Billion cubic feet (of natural gas)*

Bcfe *Bcf equivalent (of natural gas and crude oil)*

Dth *Dekatherm (Approx. 1 Mcf of natural gas)*

Mcf *Thousand cubic feet (of natural gas)*

Mcfe *Mcf equivalent (of natural gas and crude oil)*

MMcf *Million cubic feet (of natural gas)*

Tcf *Trillion cubic feet (of natural gas)*

Tcfe *Tcf equivalent (of natural gas and crude oil)*

Note

Footnotes are located on the inside back cover of this report.

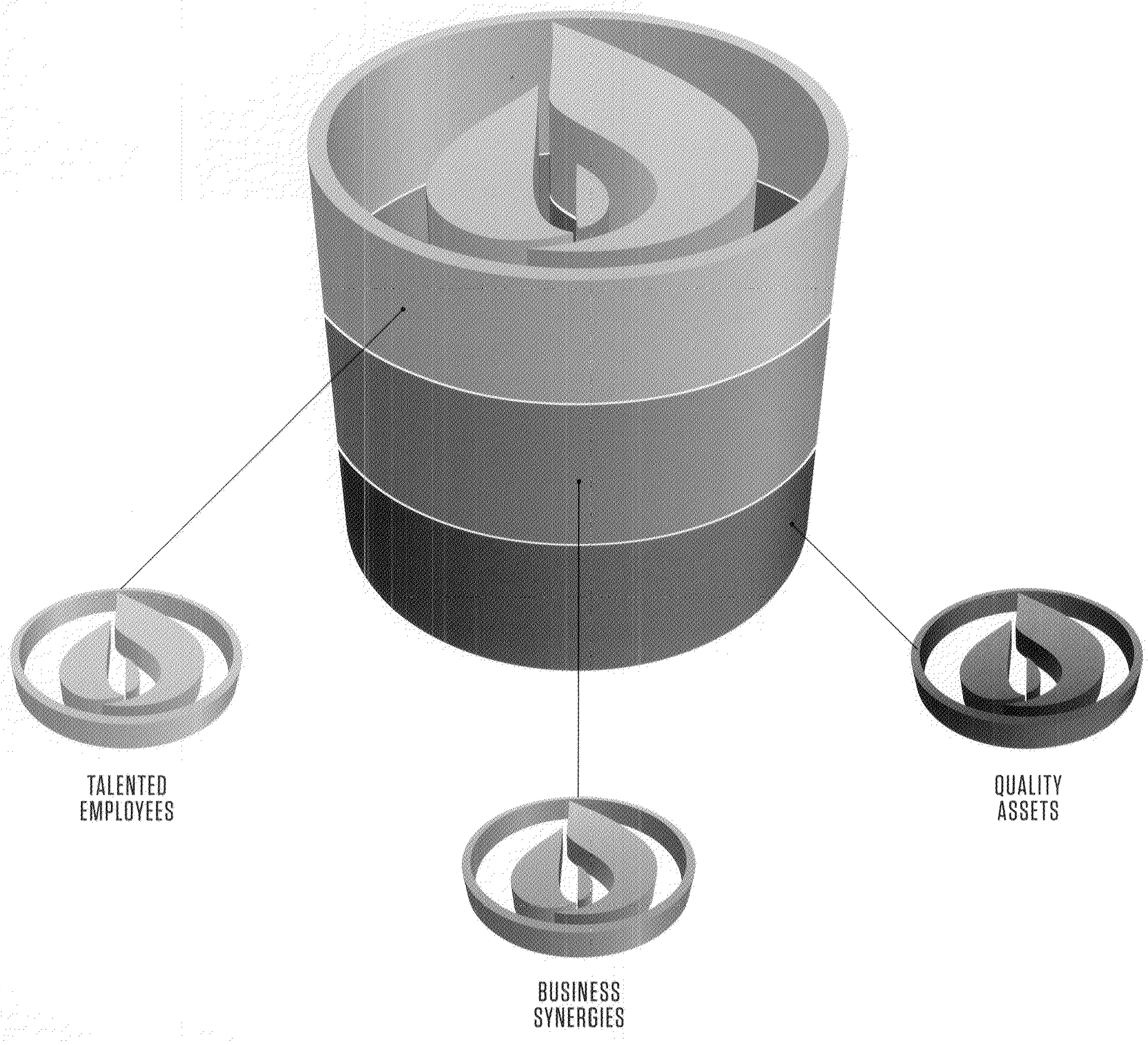
Fueled by talent and driven by value: National Fuel's highly talented workforce has the expertise to produce results, even under challenging economic conditions. Equally important is the Company's proven ability to identify and create value for shareholders and customers. These qualities are key to National Fuel's success. With a solid track record of maximizing the value of its assets across multiple operating segments, combined with its industry-leading footprint in the Marcellus Shale, National Fuel is extremely well positioned for growth as the nation increasingly recognizes natural gas as the best fuel choice for consumers, the environment and energy security.

On the Cover: *Seneca Resources' Sespe Field in California has been producing oil for over a century. In 2012, Seneca began production from the first new wells drilled in more than 20 years, demonstrating its ability to successfully optimize mature assets.*

Inside: *At-A-Glance* ▸

FLEXIBLE BY DESIGN

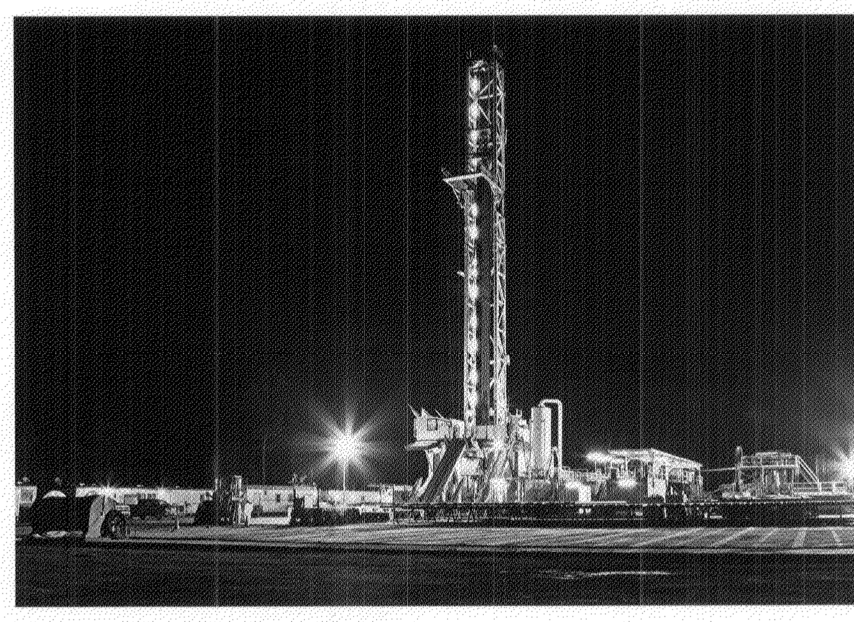
With a diverse portfolio of quality assets and wide-ranging expertise in the oil and natural gas business, National Fuel is flexible by design. Recognizing the best time to deploy or preserve capital enables the Company to focus its investment activities where, and when, the opportunities are greatest. The result is enhanced shareholder value over the long run.



UPSTREAM

SENECA RESOURCES CORPORATION

▼ *Seneca Resources' operations in Lycoming County, Pa., highlight the ability to drill multiple wells from one surface location, a practice that furthers the Company's commitment to the environment.*



83.4 Bcfe
TOTAL PRODUCTION

In 2012, Seneca grew production by 23% from the prior year, driven by an increase in both Marcellus Shale natural gas and California crude oil production.

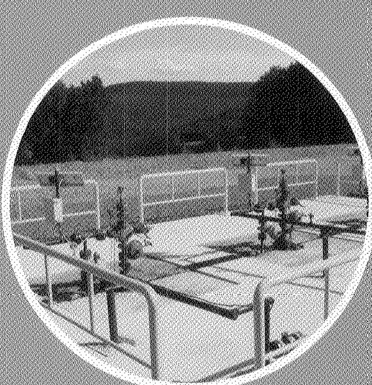
1.25 Tcfe
PROVED RESERVES

Seneca surpassed 1 trillion cubic feet equivalent of natural gas and crude oil reserves as of September 30, 2012.

The Exploration and Production segment has a great collection of natural resource assets. With 775,000 net prospective acres, the Marcellus Shale remains the centerpiece of Seneca's future growth plans. Seneca's operations are readily scalable, up or down, because the company owns, in fee, nearly 80 percent of its natural gas rights. Responding to the prolonged decline in natural gas prices, in 2012 Seneca slowed the pace of its Marcellus development plans. This preserved the strength of National Fuel's balance sheet and places the Company in a position to capitalize on economic opportunities as they arise.

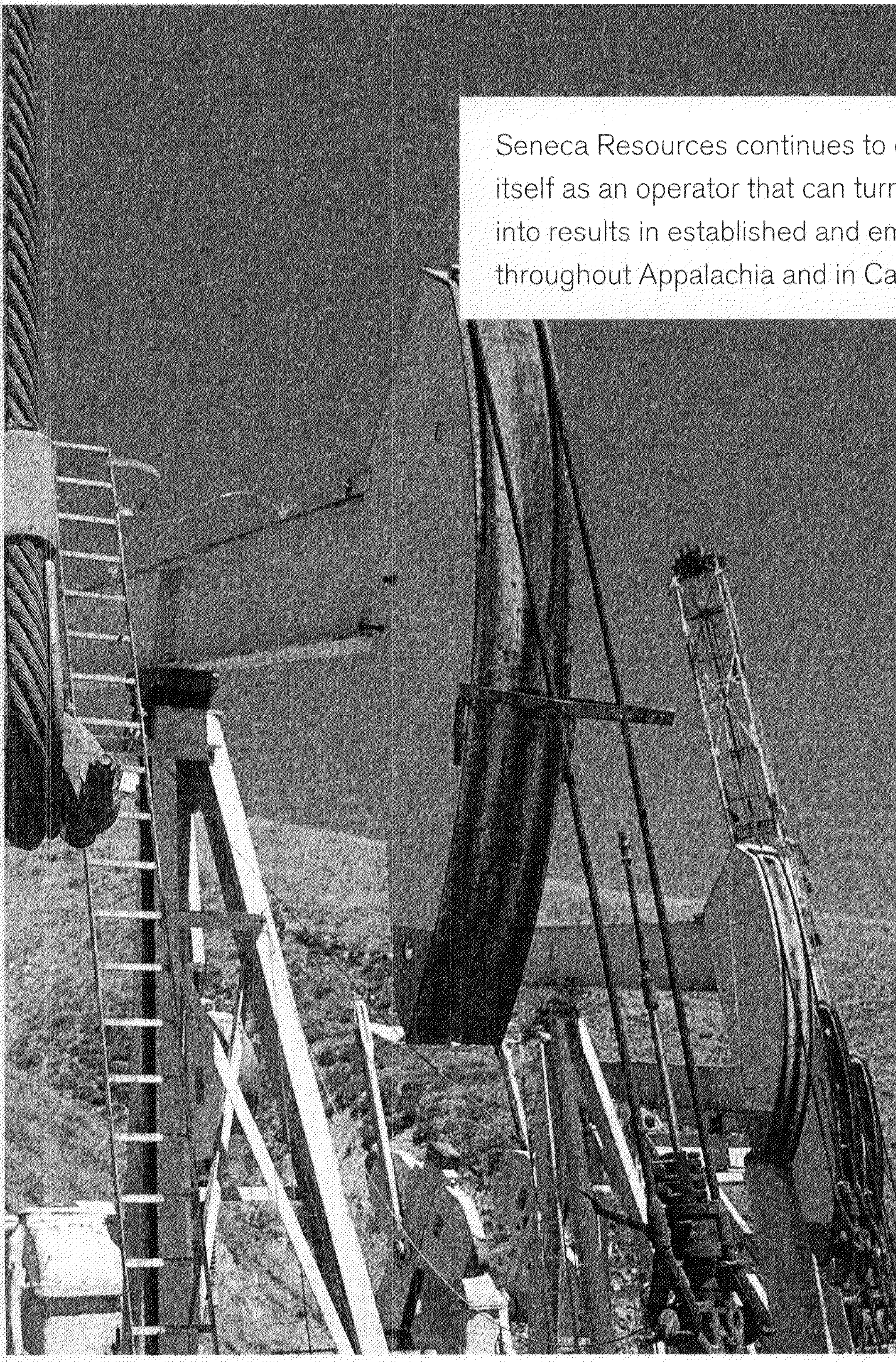
Seneca's California operations had a tremendous year, as the company posted an 8 percent increase in crude oil production, even though many of the area's fields have been active for more than a century. Seneca's employees continue to find new ways to optimize these mature fields and economically extract additional oil.

2012 also saw activities that augur well for Seneca's future. The Company is furthering its delineation efforts in the Utica Shale, a promising play that underlies much of the Company's Pennsylvania acreage. In addition, Seneca acquired properties in Kansas and California that will increase, and further diversify, the Company's oil production footprint.



PROLIFIC RESULTS — LYCOMING COUNTY, PA.

With its location in the heart of Pennsylvania, Lycoming County will play an important role in Seneca's plans during the next few years. In 2012, Seneca commenced Marcellus production from this region, seeing prolific results, with initial production rates per well ranging from 10.5 to 16.1 million cubic feet per day. These wells, on average, represent the most productive drilled by Seneca since the commencement of its Marcellus program. As a result, this area of more than 10,000 net acres will be the centerpiece of Seneca's development plans in 2013.



Seneca Resources continues to distinguish itself as an operator that can turn opportunities into results in established and emerging plays throughout Appalachia and in California.

◄ *Recent development activity in the Sespe Field in California helped drive crude oil production growth that delivers strong cash flows to fund the Company's Appalachian development.*

MIDSTREAM

NATIONAL FUEL GAS SUPPLY CORPORATION
EMPIRE PIPELINE, INC.
NATIONAL FUEL GAS MIDSTREAM CORPORATION

▲ *In Lycoming County, Pa., National Fuel Gas Midstream Corporation's Trout Run Gathering System underlying this right-of-way will provide natural gas transportation for future production from Seneca's wells being drilled by the pictured rig.*

Positioned strategically throughout Appalachia, National Fuel's gathering and FERC-regulated interstate pipeline network has been rapidly expanding to meet the needs of both natural gas producers and utility customers in the region. In fact, 2012 was an inflection point for these midstream businesses. With three major projects completed, including Empire's Tioga County Extension Project, Supply's Line N Expansion Project and NFG Midstream's Trout Run Gathering System, these businesses invested more in infrastructure during 2012 than any other year in National Fuel's history.

In addition to contributing significantly to 2012 revenue, these expansion projects are the start of a reconfiguration of the Company's pipeline network. As a result, new pipeline paths were created and additional Marcellus gathering infrastructure was constructed, creating opportunities for shippers to access key markets in the northeast and Canada. The new Tioga County Extension Project has improved flexibility for shippers, allowing them to pursue the most economic opportunities by creating bi-directional transportation routes along the system.

In 2013, the transformation of National Fuel's pipeline network is expected to continue. With two additional projects, including a second expansion to transport additional volumes into Canada, the Company is positioned to play a critical role in the ongoing development of the Marcellus and Utica shales.

▼ *Terry Kreuz and Mike Kasprzak of National Fuel Gas Supply Corporation monitor construction progress on the Northern Access Expansion Project that transports natural gas to Canadian markets.*

$375 Million
NEW INFRASTRUCTURE

During 2011 and 2012, the Company spent nearly $375 million to expand and upgrade its Appalachian infrastructure, nearly a 350% increase over the prior two-year period.

670 MMcf
DAILY EXPORT CAPACITY

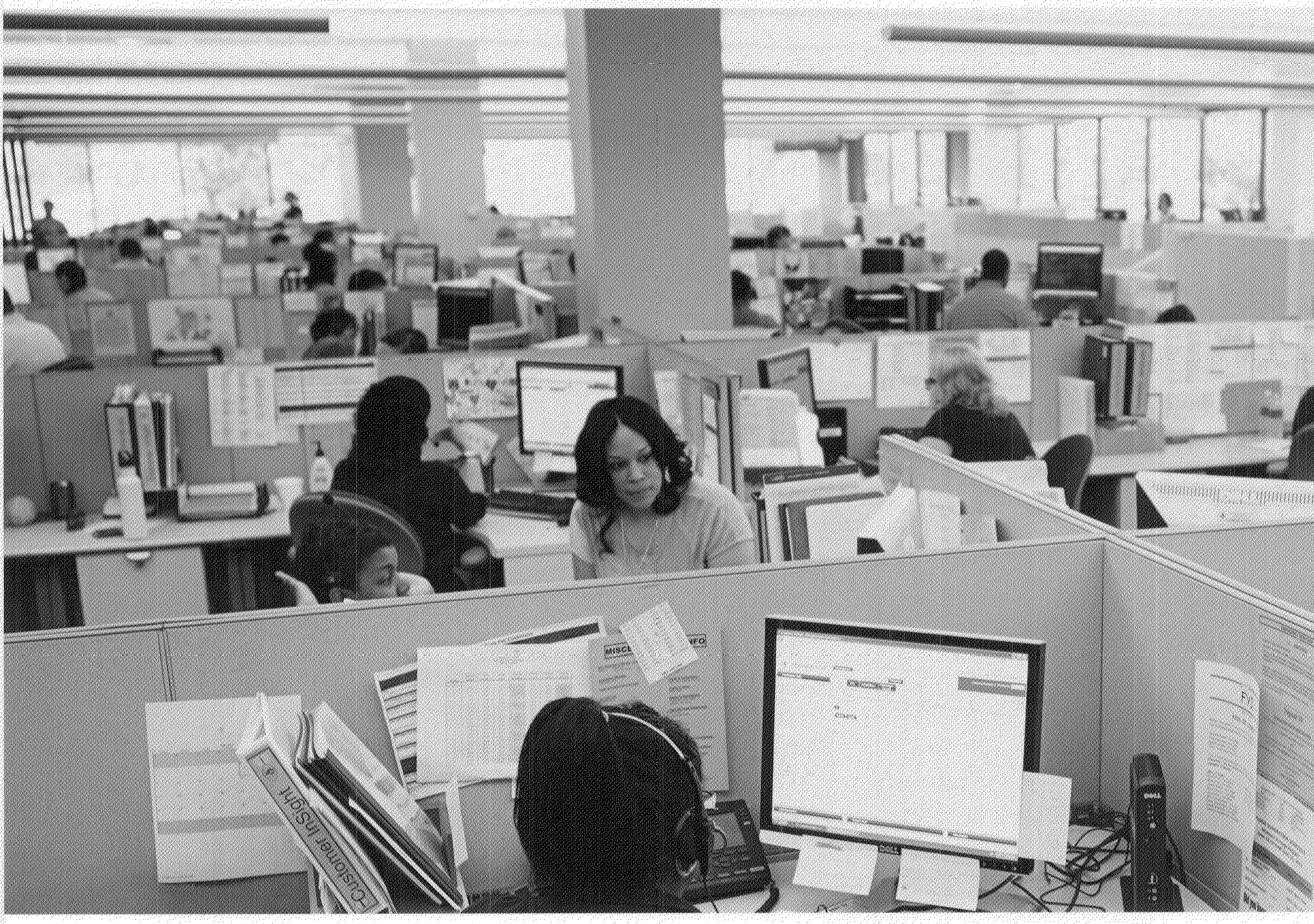
Two new projects have been completed since November 2011 that allow for the capability to export natural gas to Canada.

With a long history of building and operating natural gas pipelines in Appalachia, National Fuel is strategically positioned to be a leader in the midstream business for years to come.

▲ *Terry Falsone and Greg Maliken are working on marketing plans for projects designed to expand the Company's pipeline operations within Appalachia.*

DOWNSTREAM

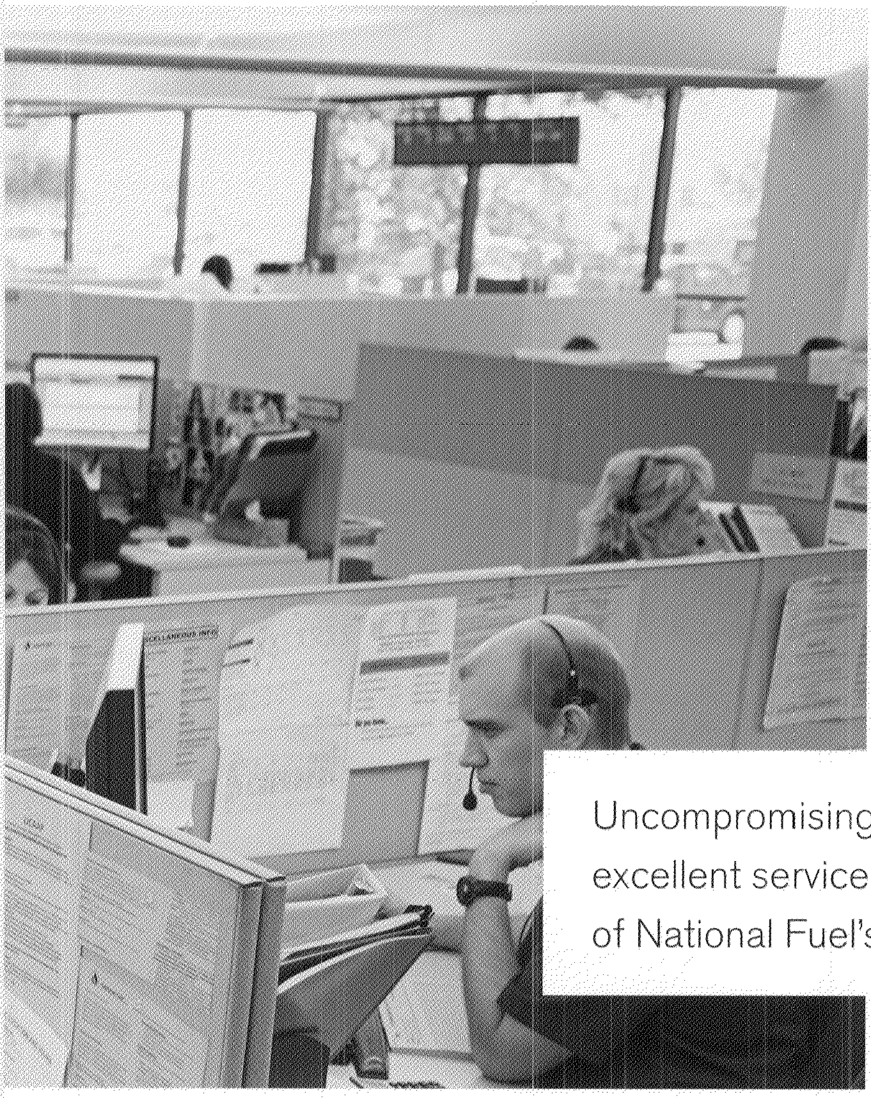
NATIONAL FUEL GAS DISTRIBUTION CORPORATION
NATIONAL FUEL RESOURCES, INC.

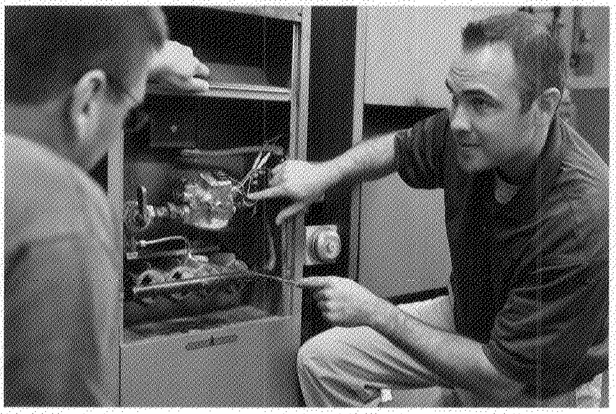


◀ *Employees of National Fuel Resources, Inc., the Company's energy marketing subsidiary, discuss natural gas delivery plans to ensure that the load demands of all its various customers are consistently met.*

Despite the dual challenges of a slow economic recovery and a very warm winter, the Utility contributed net income of $58.6 million in 2012, only 7 percent lower than in 2011. This achievement was made possible by employees' sharp focus on cost control, which yielded significant savings across many business operations. These measures, however, were not undertaken at the expense of pipeline modernization and safety, for which spending remained largely unchanged. Likewise, National Fuel's attention to excellent customer service was undiminished as the Utility, once again, exceeded its customer service performance targets, including metrics imposed by regulators.

▼ *The Utility's dedication to excellent customer service is exemplified by its commitment to efficiently answer inquiries using trained representatives. Having call centers in both New York and Pennsylvania provides overflow support and the flexibility to reroute calls in the event of a disruption.*





▲ *Utility employee Todd Woods demonstrates how to re-light natural gas appliances in the company's new state-of-the-art training facility.*

Uncompromising safety, steadfast reliability and excellent service have long been the mission of National Fuel's downstream retail operations.

On the energy marketing side, National Fuel Resources completed another year of providing a value-driven competitive alternative for thousands of natural gas customers in New York and Pennsylvania. Like the Utility, NFR's earnings dipped primarily because of the throughput declines due to the warmer weather, but year-end results still met our adjusted expectations.

Low commodity prices continue to generate significant savings for customers served by the Utility and NFR. Those savings are providing new service opportunities for the Utility, as reflected in an increase in applications for gas delivery service and growing interest in compressed natural gas as a vehicle fuel alternative to traditional motor fuels like diesel or gasoline.

8.8 Seconds

EFFICIENT CUSTOMER SERVICE

On average, for the past 12 months, customer service telephone calls to the Utility call centers were answered in 8.8 seconds.

$27 Million

CUSTOMER ASSISTANCE

In the first five years of the Conservation Incentive Program, New York utility customers have received more than $27 million in appliance rebates and low-income housing weatherization.

SAFETY & STEWARDSHIP

▲ Michael Argauer of the Company's Utility subsidiary inspects a low-pressure distribution line in Lackawanna, N.Y., maintaining National Fuel's commitment to operating a safe and reliable system.

National Fuel places safety and protection of the environment at the forefront of its operations. We continue to build and sustain a company-wide culture where safety and environmental stewardship are top priorities. Not only does the Company observe all federal, state and local regulations in its operations, it also goes beyond compliance by embracing industry best practices as a matter of course.

As part of a federal pipeline integrity program, the Company's utility and interstate pipeline subsidiaries successfully completed the first 10-year cycle of transmission pipeline integrity assessments. This program will systematically recur, and to date, the Company has inspected 694 miles of its transmission pipeline. Ensuring the operational integrity of the distribution and transmission pipeline networks remains a critical component of the Company's capital spending program, with efforts focused on replacing legacy pipelines, validating maximum pipeline operating pressures and continuing modernization of the system.

Like all National Fuel companies, Seneca Resources regularly applies best practices across its operations. From the use of third-party operational audits, to the observance of a "Zero Surface Water Discharge" policy and the creation of a Water Protection Team, these successful programs demonstrate Seneca's commitment to sound environmental practices in the communities where it operates.

The dual goals of customer safety and responsible environmental stewardship are embedded in National Fuel's internal culture, driving innovation and promoting the use of industry best practices.

▼ *The Utility continues to upgrade its vintage steel and cast iron infrastructure.*

EMPLOYEE SAFETY

2012 was a remarkable year for employee safety, with the lowest OSHA Recordable Injury Rates ever registered by National Fuel.

SYSTEM MODERNIZATION

Continuing its commitment to safety, the Utility retired or replaced more than 6,100 of its bare steel service lines in 2012.

CALIFORNIA OPERATOR OF THE YEAR

In 2012, Seneca Resources Corporation was recognized as the Bureau of Land Management's 2012 California Operator of the Year. It has taken several steps to reduce the operational risk and improve the aesthetics of its activities in the topographically challenging and environmentally sensitive areas of California's Sespe Oil Field, a mature field that has been producing for more than a century. There, Seneca has removed excess materials, reduced treating facilities from ten to two, and refinished all surface equipment to minimize the visual impact of its operations. This award reflects Seneca's and National Fuel's commitment to safety and environmental best practices across all operations.

TO OUR SHAREHOLDERS

Ronald J. Tanski
President and Chief Operating Officer

David F. Smith
Chairman of the Board and Chief Executive Officer

After several years of rapid growth, the natural gas industry experienced a slowdown in 2012 that tested the strength and adaptability of many companies.

At National Fuel, we started the year with a robust plan to further develop our Marcellus Shale acreage. With natural gas prices falling significantly, however, and in furtherance of our strategy for growth over the long run, we examined alternatives and adjusted our near-term plans by reducing Seneca Resources' rig count and delaying some Marcellus completions. This enabled us to preserve investment capital and focus on Seneca's more economic opportunities in California and in Lycoming County, Pa. We also redoubled our efforts to expand the pipeline system within our midstream businesses. Because of these actions, we maintained a healthy balance sheet and, quite unlike the asset-shedding response forced upon some of our peers, we preserved our ability to act when other investment opportunities arise. As a result, even though expectations were tempered during the year, the Company is very well positioned for future growth and solid, long-term performance.

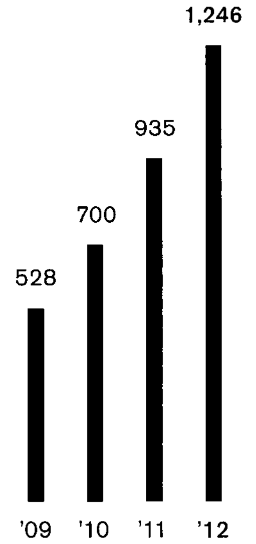
It appears that for some, the industry is following its historic boom-bust pattern of rapid expansion, followed by equally rapid contraction. National Fuel's ability to weather a low commodity price environment and preserve its future growth opportunities was an exception to that rule, and not by accident. By design, this Company boasts certain attributes that provide it with the flexibility to quickly adapt to changing circumstances.

Seneca, for example, owns most of its Marcellus acreage in fee, which allows the Company to scale development – down or up – in order to maximize opportunities without compromising long-term shareholder interests. Practically speaking, this means that we are not compelled by the requirements of limited-term leases to maintain an aggressive drilling program when current economics do not support it. In addition, the Company owns synergistically diverse assets, allowing us to allocate capital into the business segments with the best potential in response to changing market dynamics. And most importantly, our experienced and knowledgeable employees recognize when and how to pursue the most advantageous opportunities when it is valuable to our shareholders and beneficial to our customers.

Even with the substantial change to its operational program, Seneca's results continue to be better than anticipated. In May, Seneca commenced production from a new development area in Lycoming County, Pa., in conjunction with the completion of our midstream pipeline subsidiary's Trout Run Gathering System. Seneca's production from these wells is the best we have seen since the Company commenced Marcellus development in 2009. In fact, the Lycoming County wells helped to drive the Company's total production increase to 23 percent, reaching 83.4 Bcfe, and will be the main driver behind the 20 percent production growth we anticipate in 2013. As a result of this success, Seneca eclipsed 1 trillion cubic feet equivalent (Tcfe) of natural gas and crude oil proved reserves and ended the year with nearly 1.25 Tcfe. Furthermore, should natural gas prices improve, the same flexibility that allows us to scale down our development program would also enable us to readily scale it back up as circumstances warrant.

RESERVE GROWTH MILESTONE REACHED

Total Company Proved Reserves (Bcfe) at September 30

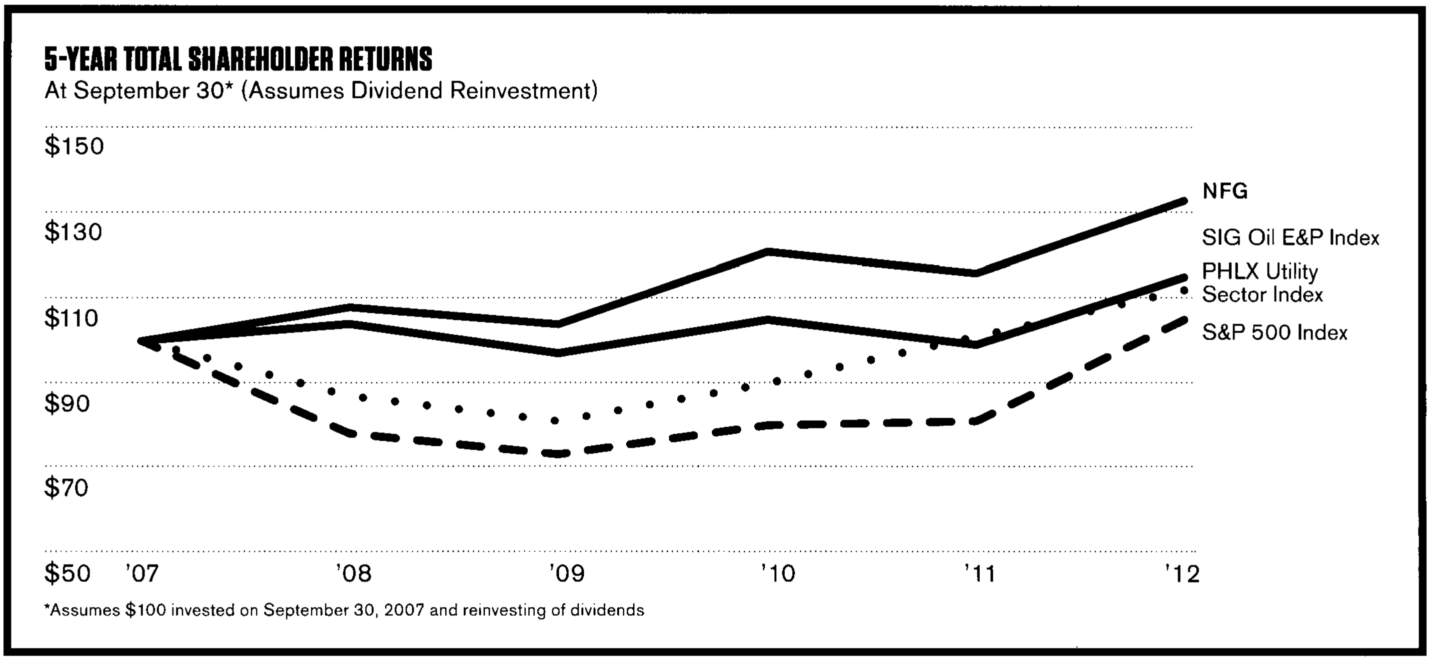


While our efforts have been focused on the Marcellus Shale, in 2012, we increased exploration activities in the deeper Utica Shale, a play that underlies much of National Fuel's Marcellus footprint. Seneca's initial test results, along with Utica data points from many other operators in the basin, show promise for enhancing the value of our Appalachian acreage. We are also pleased with the contribution of our oil operations to the Company's performance. To maintain that contribution, we completed two modest transactions in 2012. With those acquisitions we expanded our California footprint and also have diversified our asset base into an emerging basin in Kansas. Even though the impact of these transactions in 2013 will be limited, they exemplify our employees' industry expertise and our ability to deploy capital both in response to current circumstances and in furtherance of our emphasis on creating long-term value.

As expected, 2012 was an inflection point for our midstream businesses, which saw the completion of several major initiatives to expand the Company's Marcellus-area pipeline infrastructure. In the first quarter, two major expansion projects were placed in service, each unique in its own right. With its initial Line N Expansion Project, Supply Corporation has established itself as a critical provider of transportation capacity in southwestern Pennsylvania, one of the most actively developed areas in the Marcellus Shale and Appalachia. Additionally, Empire Pipeline placed the Tioga County Extension into service. A first for Appalachian pipelines, the Tioga County Extension provides the capability of exporting production into Ontario, Canada, in addition to other markets for still-increasing Marcellus Shale production.

We are pleased to report that National Fuel's remarkable record of uninterrupted dividends continued in 2012 for its 110th year and 42nd year of consecutive annual increases.

We remain focused on opportunities for continued expansion of pipeline assets in the Marcellus and Utica shale production areas. Moving forward, we are actively pursuing new projects with potential shippers to find ways to meet their needs



and to provide the infrastructure required to move their natural gas to end-use demand markets. Given our regional expertise, existing footprint, and ongoing success in efficiently shepherding projects from the drawing board to active service, we are confident that this business will play a considerable role in driving the growth we anticipate during the coming years.

The United States has never been in a more advantageous position to capture the long-term economic, geopolitical and environmental benefits that natural gas can deliver.

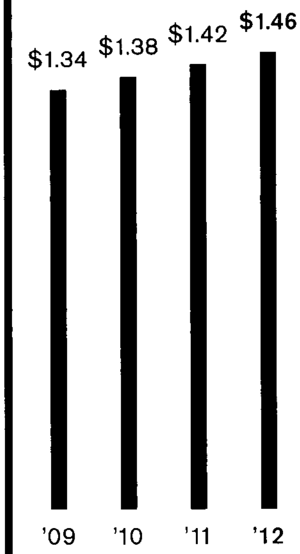
On the retail side, in 2012, our regulated Utility and energy marketing subsidiary were confronted with the twin challenges of a record-warm winter and tepid economic conditions in the companies' service areas. Despite these difficulties, the companies held their own and registered another year of solid earnings. This would not have been possible without our employees' efforts to rein in costs and increase operational efficiencies. We are very pleased with the results that those measures achieved, while spending on safety and new infrastructure in the Utility segment was maintained as a top priority.

Customers, of course, enjoyed another year of comparatively low bills and safe, reliable service. Because of the continuing low prices, residential oil and propane users are converting to natural gas utility service in increasing numbers. Industrial users, including electric generation plants, are also considering natural gas as a cleaner and more economical alternative to coal. As a vehicle fuel, natural gas' significant price and emission advantage over diesel and gasoline is attracting the interest of fleet owners, some of whom have already constructed new fueling facilities in the Utility's service territory. To capture these promising new customer opportunities, the Utility has enhanced its marketing efforts and is working with state regulators to create innovative rates and services designed to promote increased usage of natural gas.

We are also pleased to report that National Fuel's remarkable record of uninterrupted dividends continued in 2012 for its 110th year and 42nd year of consecutive annual increases. There are few companies that match this kind of reliable, long-lasting performance, and rare indeed is the energy company that can produce solid returns during prolonged commodity price declines.

This past year brought change to National Fuel's Board of Directors. David Carroll, President of the Gas Technology Institute, was elected to the Board effective June 7, 2012. David is a highly respected and nationally known leader with significant knowledge of the natural gas industry and the development of technology solutions for transmission and distribution pipeline integrity, unconventional gas production, and end-use applications. We believe that David's impressive breadth of industry experience is a reflection of this Company's commitment to maintaining a Board of Directors that is, by any measure, the best in the business. In March, George Mazanec retired from the Board after 16 years of distinguished service. With his invaluable guidance and deep understanding of the business, George exemplified the high standards of expertise and professional integrity that define the National Fuel Board. We wish him the best of luck in his retirement.

42 YEARS OF DIVIDEND INCREASES
Annualized Dividend
Rate at Fiscal Year End



The United States has never been in a more advantageous position to capture the long-term economic, geopolitical and environmental benefits that natural gas can deliver. And there are a multitude of benefits, from the obvious savings to consumers as a result of lower natural gas prices, to less obvious savings in electric rates and manufacturing costs. From an energy security perspective, increased production of domestic natural gas is already credited with reducing our dependence on foreign imports. There are environmental benefits too, as home heating customers switch from oil to cleaner-burning natural gas, and electric generation plants replace older, less efficient coal facilities with modern natural gas-fired equipment. The industry recognizes its responsibility for the protection of natural resources, and National Fuel in particular is a leader in its use of environmentally sound production and operational technologies. The fact is, natural gas production, transmission and distribution are industrial activities that, like other industrial activities that power this nation, can be undertaken with minimal negative impact on the environment. Responsible energy policy and, perhaps more reliably, economic necessity, will ensure that the nation's energy needs are increasingly fueled by natural gas. We are excited that National Fuel will continue to play an integral role during this transformative period.

Sincerely,

David F. Smith
Chairman of the Board and
Chief Executive Officer

Ronald J. Tanski
President and
Chief Operating Officer

January 7, 2013

PRINCIPAL OFFICERS

NATIONAL FUEL GAS COMPANY

David F. Smith
Chairman and Chief Executive Officer

Ronald J. Tanski
President and Chief Operating Officer

Matthew D. Cabell
Senior Vice President

James D. Ramsdell
Senior Vice President

David P. Bauer
Treasurer and Principal Financial Officer

Karen M. Camiolo
Controller and Principal Accounting Officer

Paula M. Ciprich
General Counsel and Secretary

Donna L. DeCarolis
Vice President Business Development

Principal Officers of Principal Subsidiaries

SENECA RESOURCES CORPORATION

David F. Smith
Chairman

Matthew D. Cabell
President

Barry L. McMahan
Senior Vice President and Secretary

John P. McGinnis
Senior Vice President

Cindy D. Wilkinson
Controller

NATIONAL FUEL GAS SUPPLY CORPORATION

David F. Smith
Chairman

John R. Pustulka
President

David P. Bauer
Treasurer

James R. Peterson
Secretary and General Counsel

Karen M. Camiolo
Controller

Ronald C. Kraemer
Vice President

EMPIRE PIPELINE, INC.

David F. Smith
Chairman

Ronald C. Kraemer
President

David P. Bauer
Treasurer

James R. Peterson
Secretary

Karen M. Camiolo
Controller

NATIONAL FUEL GAS DISTRIBUTION CORPORATION

David F. Smith
Chairman

Anna Marie Cellino
President

Carl M. Carlotti
Senior Vice President

Paula M. Ciprich
Secretary

Karen M. Camiolo
Controller

Richard E. Klein
Treasurer

Bruce D. Heine
Vice President

Jay W. Lesch
Vice President

Steven Wagner
Vice President

Sarah J. Mugel
Vice President and General Counsel

Ann M. Wegrzyn
Vice President

NATIONAL FUEL RESOURCES, INC.

Joseph N. Del Vecchio
Vice President

NATIONAL FUEL GAS MIDSTREAM CORPORATION

Duane A. Wassum
President

James R. Peterson
Secretary

DIRECTORS

Philip C. Ackerman [3,5^]
Former Chairman of the Board of Directors, Chief Executive Officer and President of the Company. Director of Associated Electric and Gas Insurance Services Limited. Company Director since 1994.

Robert T. Brady [2,3,4^]
Executive Chairman and Board member, former Chief Executive Officer and President of Moog Inc. Director of Astronics Corporation and M&T Bank Corporation. Member of the UB Council (State University of New York at Buffalo), member of the Board of the Buffalo Niagara Partnership and a member of the Governor's Regional Economic Development Council of Western New York. Former director of Seneca Foods Corporation. Company Director since 1995.

David C. Carroll [4]
President and Chief Executive Officer of Gas Technology Institute. Director of Versa Power Systems, Inc. Member of the Society of Gas Lighting and the Executives' Club of Chicago. Chairman of the Steering Committee for the 17th International Conference and Exhibition on Liquified Natural Gas in Houston (2013) and will become President of the International Gas Union as the United States prepares to host the 2018 World Gas Conference in Washington, D.C. Company Director since June 2012.

R. Don Cash [1,2^,4]
Chairman Emeritus and Board Director of Questar Corporation. Former Chairman, Chief Executive Officer and President of Questar Corporation. Director of Zions Bancorporation, Associated Electric and Gas Insurance Services Limited and the Ranching Heritage Association. Former Director of TODCO (The Offshore Drilling Company). Company Director since 2003.

Stephen E. Ewing [1,2,5]
Former Vice Chairman of DTE Energy. Former President and Chief Operating Officer of MCN Energy Group Inc. and Former President and Chief Executive Officer of Michigan Consolidated Gas Company. Director of CMS Energy. Trustee and immediate past Chairman of the Board of The Skillman Foundation. Chairman of the Auto Club of Michigan and Vice Chairman of the Board of the Auto Club Group (AAA). Former Chairman of the American Gas Association, the National Petroleum Council, the Midwest Gas Association and the Natural Gas Vehicle Coalition. Company Director since 2007.

Rolland E. Kidder [1,4]
Founder, former Chairman and President of Kidder Exploration, Inc., and former Trustee of the New York Power Authority. Former Director of two Appalachian-based energy associations: the Independent Oil and Gas Association of New York and the Pennsylvania Natural Gas Association. Former Executive Director of the Robert H. Jackson Center, Inc. Company Director since 2002.

Craig G. Matthews [1^,3,5]
Former President, Chief Executive Officer and Director of NUI Corporation. Former Vice Chairman, Chief Operating Officer and Director of KeySpan Corporation. Director of Hess Corporation and Board member of Republic Financial Corporation. Member and former Chairman of the Board of Trustees of Polytechnic Institute of New York University, member of the National Advisory Board for the Salvation Army and founding Chairman of the New Jersey Salvation Army Board. Company Director since February 2005.

Richard G. Reiten [2,4]
Former Chairman, Director, Chief Executive Officer and President of Northwest Natural Gas Company. Former President of Portland General Electric Company and Portland General Corporation. Director of Associated Electric and Gas Insurance Services Limited. Former Chairman and Director of the American Gas Association, former Director of Building Materials Holding Corporation, former Director of US Bancorp and former Director of IDACORP Inc. A Company Director since 2004, Mr. Reiten's Board service concludes at the 2013 Annual Meeting.

Frederic V. Salerno [2,4]
Director of GGCP, Inc. Since 2006, Mr. Salerno has also served as Senior Advisor to New Mountain Capital, L.L.C. Former Vice Chairman and Chief Financial Officer of Verizon Communications. Trustee and former President of the Inner City Scholarship Fund and former Chairman of the Board of Trustees of the State University of New York. Director of Akamai Technologies, Inc., Intercontinental Exchange, Inc., Viacom, Inc., and CBS Corporation. Former Director of Bear Stearns & Co., Inc. and Consolidated Edison, Inc., and former Chairman of the Board of Orion Power Holdings. Company Director since 2008.

David F. Smith [3^,5]
Chairman, Chief Executive Officer and former President of National Fuel Gas Company. Board member of the American Gas Association (Executive Committee), American Gas Foundation, Gas Technology Institute (Executive Committee), the Business Council of New York State (Chairman and member of the Executive Committee), the Buffalo Niagara Enterprise (immediate past Chairman and member of the Executive Committee), the State University of New York at Buffalo Law School Dean's Advisory Council and The Buffalo Sabres Foundation. Company Director since 2007.

1 Member of Audit Committee
2 Member of Compensation Committee
3 Member of Executive Committee
4 Member of Nominating/Corporate Governance Committee
5 Member of Financing Committee
^ Denotes Committee Chairman

GEORGE L. MAZANEC — 16 YEARS AS DIRECTOR

For sixteen years, George Mazanec's contribution to the National Fuel Gas Company Board of Directors has proven invaluable. With a formidable intellect and deep respect for the highest ethical standards, George played a key role in guiding the Company through a period of tremendous growth, where total assets increased from $2.1 billion in 1996 to $5.9 billion today. George's quality leadership, sound advice and tireless dedication exemplified the high standards that define National Fuel's Board.

Through the years we also enjoyed the privilege of George's and his late wife Elsa's friendship and camaraderie. Although George's service ended in March, he will long remain an important member of the National Fuel family.

FINANCIAL AND OPERATING HIGHLIGHTS

National Fuel Gas Company Year Ended September 30

	2012	2011	2010	2009	2008
Operating Revenues (Thousands)(1)	**$1,626,853**	$1,778,842	$1,760,503	$2,051,543	$2,396,837
Net Income Available for Common Stock (Thousands)	**220,077**(2)	258,402(3)	225,913(4)	100,708(5)	268,728
Return on Average Common Equity(6)	**11.4%**	14.2%	13.5%	6.3%	16.6%
Per Common Share					
Basic Earnings	**$ 2.65**	$ 3.13	$ 2.78	$ 1.26	$ 3.27
Diluted Earnings	**$ 2.63**	$ 3.09	$ 2.73	$ 1.25	$ 3.18
Dividends Paid	**$ 1.43**	$ 1.39	$ 1.35	$ 1.31	$ 1.26
Dividend Rate at Year-End	**$ 1.46**	$ 1.42	$ 1.38	$ 1.34	$ 1.30
Book Value at Year-End	**$ 23.52**	$ 22.85	$ 21.27	$ 19.74	$ 20.27
Common Shares Outstanding at Year-End	**83,330,140**	82,812,677	82,075,470	80,499,915	79,120,544
Weighted Average Common Shares Outstanding					
Basic	**83,127,844**	82,514,015	81,380,434	79,649,965	82,304,335
Diluted	**83,739,771**	83,670,802	82,660,598	80,628,685	84,474,839
Average Common Shares Traded Daily	**558,000**	534,526	411,256	551,327	654,620
Common Stock Price					
High	**$ 64.19**	$ 75.98	$ 54.42	$ 48.30	$ 63.71
Low	**$ 41.57**	$ 48.67	$ 42.83	$ 26.67	$ 38.04
Close	**$ 54.04**	$ 48.68	$ 51.81	$ 45.81	$ 42.18
Net Cash Provided by Operating Activities (Thousands)	**$ 660,787**	$ 660,546	$ 447,032	$ 611,818	$ 482,776
Total Assets (Thousands)	**$ 5,935,142**	$ 5,221,084	$ 5,047,054	$ 4,769,129	$ 4,130,187
Capital Expenditures per Statements of Cash Flows (Thousands)	**$ 1,036,784**	$ 820,872	$ 443,101	$ 313,633	$ 397,734
Volume Information					
Utility Throughput – MMcf					
Gas Sales	**64,099**	73,857	68,760	69,414	73,470
Gas Transportation	**61,027**	66,273	60,105	59,751	64,267
Pipeline & Storage Throughput – MMcf					
Gas Transportation	**371,139**	319,954	301,366	352,182	358,370
Production					
Gas – MMcf	**66,131**	50,467	30,345	22,284	22,341
Oil – Mbbl	**2,870**	2,860	3,220	3,373	3,070
Total – MMcfe	**83,351**	67,627	49,665	42,522	40,761
Proved Reserves					
Gas – MMcf	**988,434**	674,922	428,413	248,954	225,899
Oil – Mbbl	**42,862**	43,345	45,239	46,587	46,198
Total – MMcfe	**1,245,606**	934,992	699,847	528,476	503,087
Energy Marketing Volume – MMcf					
Gas	**45,756**	52,893	58,299	60,858	56,120
Average Number of Utility Retail Customers	**599,106**	609,126	619,897	624,149	627,938
Average Number of Utility Transportation Customers	**133,467**	122,474	108,850	103,176	98,925
Number of Employees at September 30	**1,874**	1,827	1,859	1,949	1,943

(1) Excludes discontinued operations.
(2) Includes elimination of other post-retirement regulatory liability of $12.8 million.
(3) Includes gain on sale of unconsolidated subsidiaries of $31.4 million.
(4) Includes gain on sale of Horizon LFG, Inc. of $6.3 million.
(5) Includes impairment of oil and gas producing properties of ($108.2) million.
(6) Calculated using average Total Comprehensive Shareholder Equity.

INVESTOR INFORMATION

Common Stock Transfer Agent and Registrar
Wells Fargo Shareowner Services
P.O. Box 64856
St. Paul, MN 55164-0856
Tel.: *800-648-8166*

Website:
http://www.shareowneronline.com

Email:
stocktransfer@wellsfargo.com

Change of address notices and inquiries about dividends should be sent to the Transfer Agent at the address listed above.

National Fuel Direct Stock Purchase and Dividend Reinvestment Plan
National Fuel offers a simple, cost-effective method for purchasing shares of National Fuel stock. A prospectus, which includes details of the Plan, can be obtained by calling, writing or emailing Wells Fargo Shareowner Services, the administrator of the Plan, at the address listed above.

Trustee for Debentures
The Bank of New York Mellon
101 Barclay Street, 8W
New York, NY 10286

Stock Exchange Listing
New York Stock Exchange
(Stock Symbol: NFG)

Annual Meeting
The Annual Meeting of Stockholders will be held at 9:30 a.m. (local time) on Thursday, March 7, 2013, at The Ritz-Carlton, Naples, 280 Vanderbilt Beach Road, Naples, FL 34108. Stockholders of record as of the close of business on January 7, 2013, will receive in the mail formal notice of the meeting, proxy statement and proxy.

Investor Relations
Investors or financial analysts desiring information should contact:

David P. Bauer
Treasurer
Tel.: *716-857-7318*

Timothy J. Silverstein
Director, Investor Relations
Tel.: *716-857-6987*
silversteint@natfuel.com

National Fuel Gas Company
6363 Main Street
Williamsville, NY 14221

Independent Accountants
PricewaterhouseCoopers LLP
3600 HSBC Center
Buffalo, NY 14203

Additional Shareholder Reports
Additional copies of this report, the 2012 Form 10-K, and the 2012 Financial and Statistical Report can be obtained without charge by writing to or calling:

Paula M. Ciprich
Corporate Secretary
Tel.: *716-857-7548*

Timothy J. Silverstein
Director, Investor Relations
Tel.: *716-857-6987*

National Fuel Gas Company
6363 Main Street
Williamsville, NY 14221

This report is printed on paper containing postconsumer fiber. The paper used in this report is also certified under the Forest Stewardship Council guidelines.

Back Cover: *The Covington area of the Company's Marcellus operations, which has been fully developed with 47 natural gas wells and a high-pressure gathering system, demonstrates the minimal long-term impact to the surrounding environment.*

At-A-Glance Footnotes:

(1) Consolidated Operating Revenue as set forth in the Company's 2012 Statement of Income and Earnings Reinvested in the Business was $1,626.9 million, including Exploration & Production, $558.2 million; Pipeline & Storage, $259.3 million; Utility, $719.1 million; Energy Marketing, $188.0 million; and Corporate and All Other, ($97.7) million (including $17.5 million for National Fuel Gas Midstream Corporation, $4.6 million in other revenue, and intersegment eliminations of ($119.8) million).

(2) Consolidated Operating Income as set forth in the Company's 2012 Statement of Income and Earnings Reinvested in the Business was $448.0 million, including Exploration & Production, $203.3 million; Pipeline & Storage, $120.4 million; Utility, $117.2 million; Energy Marketing, $5.9 million; and Corporate and All Other, $1.2 million (including $13.1 million for National Fuel Gas Midstream Corporation).

(3) Consolidated Net Income as set forth in the Company's 2012 Statement of Income and Earnings Reinvested in the Business was $220.1 million, including Exploration & Production, $96.5 million; Pipeline & Storage, $60.5 million; Utility, $58.6 million; Energy Marketing, $4.2 million; and Corporate and All Other, $0.3 million (including $6.9 million for National Fuel Gas Midstream Corporation).

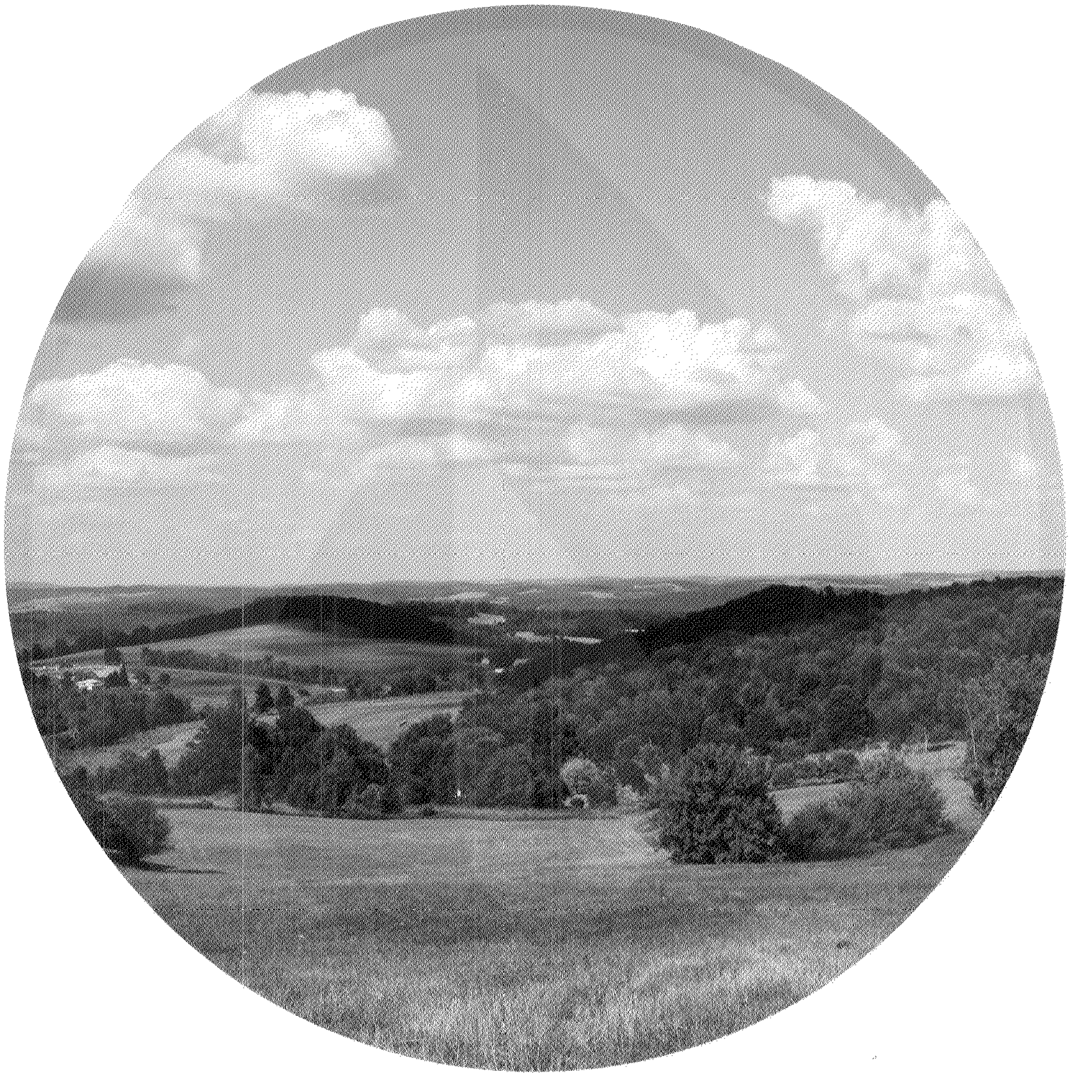
(4) National Fuel Gas Midstream Corporation's capital expenditures are included in "Expenditures for Additions to Long-Lived Assets" in the "All Other" column in the table for the year ended September 30, 2012 on page 120 of the Company's 2012 Form 10-K.

(5) Consolidated Total Assets as set forth in the Company's 2012 Balance Sheet were $5.935 billion, including Exploration & Production, $2.367 billion; Pipeline & Storage, $1.244 billion; Utility, $2.070 billion; Energy Marketing, $62.0 million; and Corporate and All Other, $191.4 million (including $116.8 million for National Fuel Gas Midstream Corporation).

This Summary Annual Report contains "forward-looking statements" as defined by the Private Securities Litigation Reform Act of 1995. Forward-looking statements should be read with the cautionary statements and important factors included in the Company's Form 10-K at Item 7, MD&A, under the heading "Safe Harbor for Forward-Looking Statements," and with the "Risk Factors" included in the Company's Form 10-K at Item 1A. Forward-looking statements are all statements other than statements of historical fact, 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 and other 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.

Forward-looking statements include estimates of oil and gas quantities. Proved oil and gas reserves are those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible under existing economic conditions, operating methods and government regulations. Other estimates of oil and gas quantities, including estimates of probable reserves, possible reserves, and resource potential, are by their nature more speculative than estimates of proved reserves. Accordingly, estimates other than proved reserves are subject to substantially greater risk of being actually realized.

This Summary Annual Report and the statements contained herein are submitted for the general information of stockholders and employees of the Company and are not intended to induce any sale or purchase of securities or to be used in connection therewith. For up-to-date information, we have two sources for your use. You may call 1-800-334-2188 at any time to receive National Fuel's current stock price and trade volume or to hear the latest news releases. You may also have news releases faxed or mailed to you. National Fuel's Web site can be found at http://www.nationalfuelgas.com. You may sign up there to receive news releases automatically by e-mail. Simply go to the News section and subscribe.



National Fuel

National Fuel Gas Company
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