NATIONAL FUEL GAS CO
Form 10-Q
August 03, 2012

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

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

For the quarterly period ended June 30, 2012

OR

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

For the transition period from ______ to ______

Commission File Number 1-3880

NATIONAL FUEL GAS COMPANY

(Exact name of registrant as specified in its charter)

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

(716) 857-7000

(Registrant s telephone number, including area code)

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

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

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

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

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

Common stock, $1 par value, outstanding at July 31, 2012: 83,306,912 shares.

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
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
IASB	International Accounting Standards Board
NYDEC	New York State Department of Environmental Conservation
NYPSC	State of New York Public Service Commission
PaPUC	Pennsylvania Public Utility Commission
PHMSA	Pipeline and Hazardous Materials Safety Administration
SEC	Securities and Exchange Commission
Other	
2011 Form 10-K	The Company s Annual Report on Form 10-K for the year ended September 30, 2011
Bbl	Barrel (of oil)
Bcf	Billion cubic feet (of natural gas)
Bcfe (or Mcfe) represents Bcf (or Mcf) Equivalent	The total heat value (Btu) of natural gas and oil expressed as a volume of natural gas. The Company uses a conversion formula of 1 barrel of oil = 6 Mcf of natural gas.
Btu	British thermal unit; the amount of heat needed to raise the temperature of one pound of water one degree Fahrenheit.
Capital expenditure	Represents additions to property, plant, and equipment, or the amount of money a company spends to buy capital assets or upgrade its existing capital assets.
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.
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act.

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Dth	Decatherm; one Dth of natural gas has a heating value of 1,000,000 British thermal units, approximately equal to the heating value of 1 Mcf of natural gas.
Exchange Act	Securities Exchange Act of 1934, as amended
Expenditures for long-lived assets	Includes capital expenditures, stock acquisitions and/or investments in partnerships.
Exploration costs	Costs incurred in identifying areas that may warrant examination, as well as costs incurred in examining specific areas, including drilling exploratory wells.
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)
NGA	The Natural Gas Act of 1938, as amended; the federal law regulating interstate natural gas pipeline and storage companies, among other things, codified beginning at 15 U.S.C. Section 717.
NYMEX	New York Mercantile Exchange. An exchange which maintains a futures market for crude oil and natural gas.
Open Season	A bidding procedure used by pipelines to allocate firm transportation or storage capacity among prospective shippers, in which all bids submitted during a defined time period are evaluated as if they had been submitted simultaneously.
PCB	Polychlorinated Biphenyl
Precedent Agreement	An agreement between a pipeline company and a potential customer to sign a service agreement after specified events (called conditions precedent) happen, usually within a specified time.
Proved developed reserves	Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.
Proved undeveloped (PUD) reserves	Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required to make these reserves productive.
Reserves	The unproduced but recoverable oil and/or gas in place in a formation which has been proven by production.

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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 Rating Service
SAR	Stock appreciation right
Service agreement	The binding agreement by which the pipeline company agrees to provide service and the shipper agrees to pay for the service.
Stock acquisitions	Investments in corporations.
Unbundled service	A service that has been separated from other services, with rates charged that reflect only the cost of the separated service.
VEBA	Voluntary Employees Beneficiary Association
WNC	Weather normalization clause; a clause in utility rates which adjusts customer rates to allow a utility to recover its normal operating costs calculated at normal temperatures. If temperatures during the measured period are warmer than normal, customer rates are adjusted upward in order to recover projected operating costs. If temperatures during the measured period are colder than normal, customer rates are adjusted downward so that only the projected operating costs will be recovered.

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The Company has nothing to report under this item.

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

This Form 10-Q contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Forward-looking statements should be read with the cautionary statements and important factors included in this Form 10-Q at Item 2 MD&A, under the heading Safe Harbor for Forward-Looking Statements. 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.

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Part I. Financial Information

Item 1. Financial Statements

National Fuel Gas Company

Consolidated Statements of Income and Earnings

Reinvested in the Business

(Unaudited)

(Thousands of Dollars, Except Per Common Share Amounts)	Three Months Ended June 30, 2012	2011
INCOME		
Operating Revenues	$ 328,861	$ 380,979
Operating Expenses		
Purchased Gas	50,160	112,725
Operation and Maintenance	93,749	95,977
Property, Franchise and Other Taxes	20,432	20,179
Depreciation, Depletion and Amortization	74,227	57,293
	238,568	286,174
Operating Income	90,293	94,805
Other Income (Expense):		
Interest Income	390	325
Other Income	1,086	1,813
Interest Expense on Long-Term Debt	(21,529)	(17,876)
Other Interest Expense	(828)	(1,159)
Income Before Income Taxes	69,412	77,908
Income Tax Expense	26,228	31,017
Net Income Available for Common Stock	43,184	46,891
EARNINGS REINVESTED IN THE BUSINESS		
Balance at April 1	1,275,107	1,180,531
	1,318,291	1,227,422
Dividends on Common Stock (2012 $0.365 per share; 2011 $0.355 per share)	(30,393)	(29,358)
Balance at June 30	$ 1,287,898	$ 1,198,064
Earnings Per Common Share:		
Basic:		
Net Income Available for Common Stock	$ 0.52	$ 0.57
Diluted:		

Net Income Available for Common Stock	$ 0.52	$ 0.56
Weighted Average Common Shares Outstanding:		
Used in Basic Calculation	83,227,602	82,687,467
Used in Diluted Calculation	83,674,823	83,782,493

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company

Consolidated Statements of Income and Earnings

Reinvested in the Business

(Unaudited)

(Thousands of Dollars, Except Per Common Share Amounts)	Nine Months Ended June 30, 2012	Nine Months Ended June 30, 2011
INCOME		
Operating Revenues	$ 1,313,593	$ 1,492,808
Operating Expenses		
Purchased Gas	390,889	582,358
Operation and Maintenance	311,857	310,148
Property, Franchise and Other Taxes	70,138	63,714
Depreciation, Depletion and Amortization	199,925	170,617
	972,809	1,126,837
Operating Income	340,784	365,971
Other Income (Expense):		
Gain on Sale of Unconsolidated Subsidiaries		50,879
Interest Income	1,686	1,277
Other Income	4,076	4,130
Interest Expense on Long-Term Debt	(60,594)	(55,994)
Other Interest Expense	(2,851)	(4,014)
Income Before Income Taxes	283,101	362,249
Income Tax Expense	111,826	141,204
Net Income Available for Common Stock	171,275	221,045
EARNINGS REINVESTED IN THE BUSINESS		
Balance at October 1	1,206,022	1,063,262
	1,377,297	1,284,307
Dividends on Common Stock (2012 $1.075 per share; 2011 $1.045 per share)	(89,399)	(86,243)
Balance at June 30	$ 1,287,898	$ 1,198,064
Earnings Per Common Share:		
Basic:		
Net Income Available for Common Stock	$ 2.06	$ 2.68
Diluted:		
Net Income Available for Common Stock	$ 2.05	$ 2.64
Weighted Average Common Shares Outstanding:		
Used in Basic Calculation	83,068,083	82,436,603

Used in Diluted Calculation	83,690,436	83,649,498

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company

Consolidated Balance Sheets

(Unaudited)

(Thousands of Dollars)	June 30, 2012	September 30, 2011
ASSETS		
Property, Plant and Equipment	$ 6,438,525	$ 5,646,918
Less Accumulated Depreciation, Depletion and Amortization	1,817,655	1,646,394
	4,620,870	4,000,524
Current Assets		
Cash and Temporary Cash Investments	140,815	80,428
Hedging Collateral Deposits	3,392	19,701
Receivables Net of Allowance for Uncollectible Accounts of $38,538 and $31,039, Respectively	113,949	131,885
Unbilled Utility Revenue	12,212	17,284
Gas Stored Underground	24,787	54,325
Materials and Supplies at average cost	28,137	27,932
Unrecovered Purchased Gas Costs	2,100	
Other Current Assets	48,246	64,923
Deferred Income Taxes	14,727	15,423
	388,365	411,901
Other Assets		
Recoverable Future Taxes	147,652	144,377
Unamortized Debt Expense	13,991	10,571
Other Regulatory Assets	481,900	484,397
Deferred Charges	5,781	5,552
Other Investments	84,495	79,365
Goodwill	5,476	5,476
Fair Value of Derivative Financial Instruments	85,905	76,085
Other	2,418	2,836
	827,618	808,659
Total Assets	$ 5,836,853	$ 5,221,084

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company

Consolidated Balance Sheets

(Unaudited)

(Thousands of Dollars)	June 30, 2012	September 30, 2011
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders Equity		
Common Stock, $1 Par Value Authorized 200,000,000 Shares; Issued And Outstanding 83,270,363 Shares and 82,812,677 Shares, Respectively	$ 83,270	$ 82,813
Paid in Capital	666,012	650,749
Earnings Reinvested in the Business	1,287,898	1,206,022
Total Common Shareholders Equity Before Items of Other Comprehensive Loss	2,037,180	1,939,584
Accumulated Other Comprehensive Loss	(47,940)	(47,699)
Total Comprehensive Shareholders Equity	1,989,240	1,891,885
Long-Term Debt, Net of Current Portion	1,149,000	899,000
Total Capitalization	3,138,240	2,790,885
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	70,200	40,000
Current Portion of Long-Term Debt	250,000	150,000
Accounts Payable	88,119	126,709
Amounts Payable to Customers	17,761	15,519
Dividends Payable	30,393	29,399
Interest Payable on Long-Term Debt	16,320	25,512
Customer Advances	315	19,643
Customer Security Deposits	16,847	17,321
Other Accruals and Current Liabilities	160,899	108,636
Fair Value of Derivative Financial Instruments	16,193	9,728
	667,047	542,467
Deferred Credits		
Deferred Income Taxes	1,062,824	955,384
Taxes Refundable to Customers	65,554	65,543
Unamortized Investment Tax Credit	2,150	2,586
Cost of Removal Regulatory Liability	148,668	135,940
Other Regulatory Liabilities	39,657	17,177
Pension and Other Post-Retirement Liabilities	481,331	481,520
Asset Retirement Obligations	78,232	75,731
Other Deferred Credits	153,150	153,851
	2,031,566	1,887,732
Commitments and Contingencies		

Total Capitalization and Liabilities	$ 5,836,853	$ 5,221,084

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company

Consolidated Statements of Cash Flows

(Unaudited)

(Thousands of Dollars)	Nine Months Ended June 30, 2012	2011
OPERATING ACTIVITIES		
Net Income Available for Common Stock	$ 171,275	$ 221,045
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Gain on Sale of Unconsolidated Subsidiaries		(50,879)
Depreciation, Depletion and Amortization	199,925	170,617
Deferred Income Taxes	104,948	140,326
Excess Tax Costs (Benefits) Associated with Stock-Based Compensation Awards	(1,511)	1,224
Other	6,618	7,351
Change in:		
Hedging Collateral Deposits	16,309	(26,850)
Receivables and Unbilled Utility Revenue	23,008	(25,919)
Gas Stored Underground and Materials and Supplies	30,853	22,387
Unrecovered Purchased Gas Costs	(2,100)	
Prepayments and Other Current Assets	18,190	83,541
Accounts Payable	(38,590)	5,506
Amounts Payable to Customers	2,242	(12,448)
Customer Advances	(19,328)	(26,617)
Customer Security Deposits	(474)	(648)
Other Accruals and Current Liabilities	17,083	36,446
Other Assets	(12,796)	8,582
Other Liabilities	25,338	(17,382)
Net Cash Provided by Operating Activities	540,990	536,282
INVESTING ACTIVITIES		
Capital Expenditures	(776,896)	(583,739)
Net Proceeds from Sale of Unconsolidated Subsidiaries		59,365
Net Proceeds from Sale of Oil and Gas Producing Properties		69,435
Other	(1,267)	(2,908)
Net Cash Used in Investing Activities	(778,163)	(457,847)
FINANCING ACTIVITIES		
Changes in Notes Payable to Banks and Commercial Paper	30,200	
Excess Tax (Costs) Benefits Associated with Stock-Based Compensation Awards	1,511	(1,224)
Net Proceeds from Issuance of Long-Term Debt	496,085	
Reduction of Long-Term Debt	(150,000)	(200,000)
Dividends Paid on Common Stock	(88,404)	(85,201)
Net Proceeds from Issuance (Repurchase) of Common Stock	8,168	(4,471)
Net Cash Provided by (Used in) Financing Activities	297,560	(290,896)
Net Increase (Decrease) in Cash and Temporary Cash Investments	60,387	(212,461)
Cash and Temporary Cash Investments at October 1	80,428	397,171

Cash and Temporary Cash Investments at June 30	$ 140,815	$ 184,710

See Notes to Condensed Consolidated Financial Statements

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National Fuel Gas Company

Consolidated Statements of Comprehensive Income

(Unaudited)

(Thousands of Dollars)	Three Months Ended June 30, 2012	Three Months Ended June 30, 2011
Net Income Available for Common Stock	$ 43,184	$ 46,891
Other Comprehensive Income (Loss), Before Tax:		
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	(1,870)	23
Unrealized Gain on Derivative Financial Instruments Arising During the Period	30,432	26,378
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	(21,599)	3,185
Other Comprehensive Income, Before Tax	6,963	29,586
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) On Securities Available for Sale Arising During the Period	(701)	8
Income Tax Expense Related to Unrealized Gain on Derivative Financial Instruments Arising During the Period	12,688	10,810
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) from Derivative Financial Instruments In Net Income	(8,973)	1,345
Income Taxes Net	3,014	12,163
Other Comprehensive Income	3,949	17,423
Comprehensive Income	$ 47,133	$ 64,314

(Thousands of Dollars)	Nine Months Ended June 30, 2012	Nine Months Ended June 30, 2011
Net Income Available for Common Stock	$ 171,275	$ 221,045
Other Comprehensive Income (Loss), Before Tax:		
Foreign Currency Translation Adjustment		17
Reclassification Adjustment for Realized Foreign Currency Translation Loss in Net Income		34
Unrealized Gain on Securities Available for Sale Arising During the Period	1,959	3,461
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	47,085	(41,602)
Reclassification Adjustment for Realized Gains on Derivative Financial Instruments in Net Income	(49,649)	(13,080)
Other Comprehensive Loss, Before Tax	(605)	(51,170)
Income Tax Expense Related to Unrealized Gain on Securities Available for Sale Arising During the Period	723	1,306
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	14,346	(17,136)
Reclassification Adjustment for Income Tax Expense on Realized Gains from Derivative Financial Instruments In Net Income	(15,433)	(5,227)

Income Taxes Net	(364)	(21,057)
Other Comprehensive Loss	(241)	(30,113)
Comprehensive Income	$ 171,034	$ 190,932

See Notes to Condensed Consolidated Financial Statements

National Fuel Gas Company

Notes to Condensed Consolidated Financial Statements

(Unaudited)

Note 1 Summary of Significant Accounting Policies

Principles of Consolidation. The Company consolidates all entities in which it has a controlling financial interest. 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.

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.

Reclassification. 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. In the Consolidated Statement of Cash Flows for the nine months ended June 30, 2011, the change in Other Liabilities was reduced by $1.9 million and the change in Other Assets was increased by $1.9 million.

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 which will be passed back to ratepayers over a twelve-month period. These reclassifications did not impact the Consolidated Statement of Income. However, the reclassifications did impact the Consolidated Statement of Cash Flows for the nine months ended June 30, 2011. On that statement, the line item labeled Prepayments and Other Current Assets was increased by $13.6 million and the line item labeled Other Assets was reduced by $13.6 million. Additionally, the line item labeled Other Accruals and Current Liabilities was reduced by $0.3 million and the line item labeled Other Liabilities was increased by $0.3 million.

Earnings for Interim Periods. The Company, in its opinion, has included all adjustments that are necessary for a fair statement of the results of operations for the reported periods. The consolidated financial statements and notes thereto, included herein, should be read in conjunction with the financial statements and notes for the years ended September 30, 2011, 2010 and 2009 that are included in the Company s 2011 Form 10-K. The consolidated financial statements for the year ended September 30, 2012 will be audited by the Company s independent registered public accounting firm after the end of the fiscal year.

The earnings for the nine months ended June 30, 2012 should not be taken as a prediction of earnings for the entire fiscal year ending September 30, 2012. Most of the business of the Utility and Energy Marketing segments is seasonal in nature and is influenced by weather conditions. Due to the seasonal nature of the heating business in the Utility and Energy Marketing segments, earnings during the winter months normally represent a substantial part of the earnings that those segments are expected to achieve for the entire fiscal year. The Company s business segments are discussed more fully in Note 7 Business Segment Information.

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

At June 30, 2012, the Company accrued $98.4 million of capital expenditures. This amount was excluded from the Consolidated Statement of Cash Flows at June 30, 2012 since it represents a non-cash investing activity at that date. Accrued capital expenditures at June 30, 2012 are included in Other Accruals and Current Liabilities on the Consolidated Balance Sheet.

At September 30, 2011, the Company accrued $72.2 million of capital expenditures. This amount was excluded from the Consolidated Statement of Cash Flows at September 30, 2011 since it represented a non-cash investing activity at that date. These capital expenditures were paid during the quarter ended December 31, 2011 and have been included in the Consolidated Statement of Cash Flows for the nine months ended June 30, 2012. Accrued capital expenditures at September 30, 2011 are included in Other Accruals and Current Liabilities on the Consolidated Balance Sheet.

At June 30, 2011, the Company accrued $66.6 million of capital expenditures. This amount was excluded from the Consolidated Statement of Cash Flows at June 30, 2011 since it represented a non-cash investing activity at that date.

At September 30, 2010, the Company accrued $55.5 million of capital expenditures. This amount was excluded from the Consolidated Statement of Cash Flows at September 30, 2010 since it represented a non-cash investing activity at that date. These capital expenditures were paid during the quarter ended December 31, 2010 and have been included in the Consolidated Statement of Cash Flows for the nine months ended June 30, 2011.

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 June 30, 2012, the Company had hedging collateral deposits of $3.4 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 instruments liability or asset balances.

Gas Stored Underground Current. In the Utility segment, gas stored underground current is carried at lower of cost or market, on a LIFO method. Gas stored underground current normally declines during the first and second quarters of the year and is replenished during the third and fourth quarters. In the Utility segment, the current cost of replacing gas withdrawn from storage is recorded in the Consolidated Statements of Income and a reserve for gas replacement is recorded in the Consolidated Balance Sheets under the caption Other Accruals and Current Liabilities. Such reserve, which amounted to $30.5 million at June 30, 2012, is reduced to zero by September 30 of each year as the inventory is replenished.

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

Capitalized costs include costs related to unproved properties, which are excluded from amortization until proved reserves are found or it is determined that the unproved properties are impaired. Such costs amounted to $147.8 million and $226.3 million at June 30, 2012 and September 30, 2011, respectively. All costs related to unproved properties are reviewed quarterly to determine if impairment has occurred. The amount of any impairment is transferred to the pool of capitalized costs being amortized.

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In April 2011, the Company completed the sale of its offshore oil and natural gas properties in the Gulf of Mexico. Initial proceeds received through June 30, 2011 totaled $61.8 million. Price adjustments subsequent to June 30, 2011 reduced the final net proceeds to $55.4 million.

Capitalized costs are subject to the SEC full cost ceiling test. The ceiling test, which is performed each quarter, determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. The ceiling under this test represents (a) the present value of estimated future net cash flows, excluding future cash outflows associated with settling asset retirement obligations that have been accrued on the balance sheet, using a discount factor of 10%, which is computed by applying prices of oil and gas (as adjusted for hedging) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet, less estimated future expenditures, plus (b) the cost of unevaluated properties not being depleted, less (c) income tax effects related to the differences between the book and tax basis of the properties. The natural gas and oil prices used to calculate the full cost ceiling are based on an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period. If capitalized costs, net of accumulated depreciation, depletion and amortization and related deferred income taxes, exceed the ceiling at the end of any quarter, a permanent impairment is required to be charged to earnings in that quarter. At June 30, 2012, the ceiling exceeded the book value of the oil and gas properties by approximately $107.0 million.

Accumulated Other Comprehensive Loss. The components of Accumulated Other Comprehensive Loss, net of related tax effect, are as follows (in thousands):

	At June 30, 2012	At September 30, 2011
Funded Status of the Pension and Other Post-Retirement Benefit Plans	$ (89,587)	$ (89,587)
Net Unrealized Gain on Derivative Financial Instruments	39,502	40,979
Net Unrealized Gain on Securities Available for Sale	2,145	909
Accumulated Other Comprehensive Loss	$ (47,940)	$ (47,699)

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

	At June 30, 2012	At September 30, 2011
Prepayments	$ 9,762	$ 9,489
Prepaid Property and Other Taxes	11,020	13,240
Federal Income Taxes Receivable	385	385
State Income Taxes Receivable		6,124
Fair Values of Firm Commitments	5,479	9,096
Regulatory Assets	21,600	26,589
	$ 48,246	$ 64,923

Earnings Per Common Share. Basic earnings per common share is computed by dividing net 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. There were 976,870 and 833,170 securities excluded as being antidilutive for the quarter and nine months ended June 30, 2012, respectively. There were 6,512 securities excluded as being antidilutive for the quarter ended June 30, 2011. There were no antidilutive securities for the nine months ended June 30, 2011.

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Stock-Based Compensation. During the nine months ended June 30, 2012, the Company granted 166,000 non-performance based SARs having a weighted average exercise price of $55.09 per share. The weighted average grant date fair value of these SARs was $11.20 per share. These SARs will be settled in shares of common stock of the Company and are considered equity awards under the current authoritative guidance for stock-based compensation. The accounting for those SARs is the same as the accounting for stock options. The non-performance based SARs granted during the nine months ended June 30, 2012 vest annually in one-third increments and become exercisable on the third anniversary of the date of grant. The weighted average grant date fair value of these non-performance based SARs granted during the nine months ended June 30, 2012 was estimated on the date of grant using the same accounting treatment that is applied for stock options. There were no stock options granted during the nine months ended June 30, 2012.

The Company granted 41,525 restricted share awards (non-vested stock as defined by the current accounting literature) during the nine months ended June 30, 2012. The weighted average fair value of such restricted shares was $55.09 per share. In addition, the Company granted 68,450 restricted stock units during the nine months ended June 30, 2012. The weighted average fair value of such restricted stock units was $47.10 per share for the nine months ended June 30, 2012. 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 participant to receive dividends during the vesting period. 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 must be reduced by the present value of forgone dividends over the vesting term of the award.

The Company did not fully recognize a tax benefit from excess tax deductions related to stock-based compensation for calendar years 2009 through 2011 due to tax loss carryforwards. The Company expects to recognize additional tax benefits of $32.2 million as an adjustment to Paid in Capital in future years as the tax loss carryforwards are utilized.

New Authoritative Accounting and Financial Reporting Guidance. In May 2011, the FASB issued authoritative guidance regarding fair value measurement as a joint project with the IASB. The objective of the guidance was to bring together as closely as possible the fair value measurement and disclosure guidance issued by the two boards. The guidance includes a few updates to measurement guidance and some enhanced disclosure requirements. For all Level 3 fair value measurements, the guidance requires quantitative information about significant unobservable inputs used and a description of the valuation processes in place. The guidance also requires a qualitative discussion about the sensitivity of recurring Level 3 fair value measurements and information about any transfers between Level 1 and Level 2 of the fair value hierarchy. The new guidance also contains a requirement that all fair value measurements, whether they are recorded on the balance sheet or disclosed in the footnotes, be classified as Level 1, Level 2 or Level 3 within the fair value hierarchy. This authoritative guidance became effective for the quarter ended March 31, 2012. The Company has updated its disclosures to reflect the new requirements in Note 2 Fair Value Measurements.

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 results of operations.

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. While early adoption is permitted, the Company has not adopted the new provisions to date.

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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 2 Fair Value Measurements

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

The following table sets forth, by level within the fair value hierarchy, the Company s financial assets and liabilities (as applicable) that were accounted for at fair value on a recurring basis as of June 30, 2012 and September 30, 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 June 30, 2012				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments(1)	Total
Assets:					
Cash Equivalents Money Market Mutual Funds	$ 117,813	$	$	$	$ 117,813
Derivative Financial Instruments:					
Commodity Futures Contracts Gas	4,396			(4,396)	
Over the Counter Swaps Oil			3,124	(4,649)	(1,525)
Over the Counter Swaps Gas		95,114		(7,684)	87,430
Other Investments:					
Balanced Equity Mutual Fund	23,629				23,629
Common Stock Financial Services Industry	4,304				4,304
Other Common Stock	279				279
Hedging Collateral Deposits	3,392				3,392
Total	$ 153,813	$ 95,114	$ 3,124	$ (16,729)	$ 235,322
Liabilities:					
Derivative Financial Instruments:					
Commodity Futures Contracts Gas	$ 5,558	$	$	$ (4,396)	$ 1,162
Over the Counter Swaps Oil			19,672	(4,649)	15,023
Over the Counter Swaps Gas		7,692		(7,684)	8
Total	$ 5,558	$ 7,692	$ 19,672	$ (16,729)	$ 16,193
Total Net Assets/(Liabilities)	$ 148,255	$ 87,422	$ (16,548)	$	$ 219,129

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Recurring Fair Value Measures	At fair value as of September 30, 2011				
(Thousands of Dollars)	Level 1	Level 2	Level 3	Netting Adjustments[1]	Total
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 June 30, 2012, the derivative financial instruments reported in Level 1 consist of natural gas NYMEX futures contracts used in the Company s Energy Marketing and Pipeline and Storage segments (at September 30, 2011, the derivative financial instruments reported in Level 1 consist of NYMEX futures used in the Company s Energy Marketing segment). Hedging collateral deposits of $3.4 million (at June 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 at June 30, 2012 and September 30, 2011 consist of natural gas price swap agreements used in the Company s Exploration and Production and Energy Marketing segments. 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 all of the Company s Exploration and Production segment s crude oil price swap agreements at June 30, 2012 and 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 over-the-counter crude oil swaps is the basis differential between Midway Sunset oil and NYMEX contracts. Significant changes in the assumed basis differential could result in a significant change in value of the derivative financial instruments. At June 30, 2012, it was assumed that Midway Sunset oil was 111.5% 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 June 30, 2012 had been 10 percentage points lower, the fair value of the Level 3 crude oil price swap agreements would have changed from a net liability of $16.5 million to a net asset of $5.4 million. If the basis differential between Midway Sunset oil and NYMEX contracts used in the fair value measurement

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at June 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 $21.8 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 and Level 3 assets (after netting arrangements) has been reduced by $0.6 million at June 30, 2012 and the fair market value of the price swap agreements reported as Level 2 and Level 3 assets (after netting arrangements) has been reduced by $2.0 million at September 30, 2011. 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 June 30, 2012 has been reduced by less than $0.1 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 quarters and nine months ended June 30, 2012 and 2011, respectively. For the quarters and nine months ended June 30, 2012 and June 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)
(Thousands of Dollars)

		Total Gains/Losses			
	April 1, 2012	(Gains)/ Losses Realized and Included in Earnings	Gains/(Losses) Unrealized and Included in Other Comprehensive Income (Loss)	Transfer In/Out of Level 3	June 30, 2012
Derivative Financial Instruments[2]	$ (68,754)	$ 10,392[1]	$ 41,814	$	$ (16,548)

[1] Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the three months ended June 30, 2012.
[2] Derivative Financial Instruments are shown on a net basis.

Fair Value Measurements Using Unobservable Inputs (Level 3)
(Thousands of Dollars)

		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	June 30, 2012
Derivative Financial Instruments[2]	$ (5,410)	$ 36,526[1]	$ (47,664)	$	$ (16,548)

[1] Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the nine months ended June 30, 2012.
[2] Derivative Financial Instruments are shown on a net basis.

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Fair Value Measurements Using Unobservable Inputs (Level 3)
(Thousands of Dollars)

	April 1, 2011	Total Gains/Losses (Gains)/Losses Realized and Included in Earnings	Gains/(Losses) Unrealized and Included in Other Comprehensive Income (Loss)	Transfer In/Out of Level 3	June 30, 2011
Derivative Financial Instruments[(2)]	$ (71,913)	$ 15,377[(1)]	$ 6,083	$	$ (50,453)

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the three months ended June 30, 2011.
(2) Derivative Financial Instruments are shown on a net basis.

Fair Value Measurements Using Unobservable Inputs (Level 3)
(Thousands of Dollars)

	October 1, 2010	Total Gains/Losses (Gains)/Losses Realized and Included in Earnings	Gains/(Losses) Unrealized and Included in Other Comprehensive Income (Loss)	Transfer In/Out of Level 3	June 30, 2011
Derivative Financial Instruments[(2)]	$ (16,483)	$ 28,545[(1)]	$ (62,515)	$	$ (50,453)

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the nine months ended June 30, 2011.
(2) Derivative Financial Instruments are shown on a net basis.

Note 3 Financial Instruments

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

	June 30, 2012		September 30, 2011	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt	$ 1,399,000	$ 1,595,554	$ 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.

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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 $56.3 million and $54.8 million at June 30, 2012 and September 30, 2011, respectively. The fair value of the equity mutual fund was $23.6 million at June 30, 2012 and $19.9 million at September 30, 2011. The gross unrealized gain on this equity mutual fund was $1.4 million at June 30, 2012. The gross unrealized loss on the equity mutual fund was $0.7 million at September 30, 2011. The fair value of the stock of an insurance company was $4.3 million at June 30, 2012 and $4.5 million at September 30, 2011. The gross unrealized gain on this stock was $1.9 million at June 30, 2012 and $2.1 million at September 30, 2011. The insurance contracts and marketable equity securities are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees.

Derivative Financial Instruments. The Company uses derivative instruments to manage commodity price risk in the Exploration and Production, 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 June 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 June 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	138.9 Bcf (all short positions)
Crude Oil	2,529,000 Bbls (all short positions)

As of June 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 purchases (where the Company uses long positions (i.e. positions that pay-off in the event of commodity price increases) to mitigate the risk of increasing natural gas prices, which would lead to increased purchased gas expense and decreased earnings):

Commodity	**Units**
Natural Gas	6.9 Bcf (5.6 Bcf short positions (mostly forecasted storage withdrawals) and 1.3 Bcf long positions (mostly forecasted storage injections))

As of June 30, 2012, the Company s Pipeline and Storage segment has the following commodity derivative contracts (futures contracts) 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):

Commodity	**Units**
Natural Gas	2.3 Bcf (all short positions)

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As of June 30, 2012, the Company s Exploration and Production segment had $69.7 million ($40.6 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that $60.1 million ($35.1 million after tax) of these gains will be reclassified into the Consolidated Statement of Income within the next 12 months as the expected sales of the underlying commodities occur. See Note 1, 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.

As of June 30, 2012, the Company s Energy Marketing segment had $1.2 million ($0.7 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 (Loss) within the next 12 months as the expected sales of the underlying commodity occurs. See Note 1, 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.

As of June 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 (Loss) within the next 12 months as the expected sales of the underlying commodity occurs. See Note 1, 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.

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The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the

Three Months Ended June 30, 2012 and 2011 (Thousands of Dollars)

Derivatives in Cash Flow Hedging Relationships		**Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive Income (Loss) on the Consolidated Statement of Comprehensive Income (Loss) (Effective Portion) for the Three Months Ended June 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 Three Months Ended June 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 Three Months Ended June 30,**	
		2012	2011		2012	2011		2012	2011
Commodity Contracts	Exploration & Production segment	$ 31,358	$ 25,399	Operating Revenue	$ 20,643	$ (5,548)	Operating Revenue	$	$ 570
Commodity Contracts	Energy Marketing segment	$ (201)	$ 737	Purchased Gas	$ 956	$ 1,793	Operating Revenue	$	$
Commodity Contracts	Pipeline & Storage segment	$ (725)	$ 242	Operating Revenue	$	$	Operating Revenue	$	$
Total		$ 30,432	$ 26,378		$ 21,599	$ (3,755)		$	$ 570

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The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the

Nine Months Ended June 30, 2012 and 2011 (Thousands of Dollars)

Derivatives in Cash Flow Hedging Relationships	**Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive Income (Loss) on the Consolidated Statement of Comprehensive Income (Loss) (Effective Portion) for the Nine Months Ended June 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 Nine Months Ended June 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 Nine Months Ended June 30,**	
	2012	2011		2012	2011		2012	2011
Commodity Contracts Exploration & Production segment	$ 40,897	$ (42,969)	Operating Revenue	$ 38,633	$ 5,415	Operating Revenue	$	$ 570
Commodity Contracts Energy Marketing segment	$ 6,337	$ 1,340	Purchased Gas	$ 10,440	$ 7,095	Operating Revenue	$	$
Commodity Contracts Pipeline & Storage segment	$ (149)	$ 27	Operating Revenue	$ 576	$	Operating Revenue	$	$
Total	$ 47,085	$ (41,602)		$ 49,649	$ 12,510		$	$ 570

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 June 30, 2012, the Company s Energy Marketing segment had fair value hedges covering approximately 10.5 Bcf (8.8 Bcf of fixed price sales commitments (all long positions), 1.4 Bcf of fixed price purchase commitments (all short positions) and 0.3 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.

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Consolidated Statement of Income	**Gain/ (Loss) on Derivative**	**Gain/ (Loss) on Commitment**
Operating Revenues	$ 4,304,103	$ (4,304,103)
Purchased Gas	$ (196,930)	$ 196,930

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 Nine Months Ended June 30, 2012 (In Thousands)**
Commodity Contracts Hedge of fixed price sales commitments of natural gas	Operating Revenues	$ 4,304
Commodity Contracts Hedge of fixed price purchase commitments of natural gas	Purchased Gas	$ (320)
Commodity Contracts Hedge of natural gas held in storage	Purchased Gas	$ 123
		$ 4,107

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 eleven are in a net gain position. On average, the Company had $7.8 million of credit exposure per counterparty in a gain position at June 30, 2012. The maximum credit exposure per counterparty in a gain position at June 30, 2012 was $17.1 million. As of June 30, 2012, the Company had not received any collateral from the counterparties having credit-risk related contingency features in their derivative instrument contracts. 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 June 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 June 30, 2012, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $60.6 million according to the Company s internal model (discussed in Note 2 Fair Value Measurements). At June 30, 2012, the fair market value of the derivative financial instrument liabilities with a credit-risk related contingency feature was $15.0 million according to the Company s internal model (discussed in Note 2 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 June 30, 2012.

For its exchange traded futures contracts, which are in a liability position, the Company had posted $3.4 million in hedging collateral deposits as of June 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.

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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 1 under Hedging Collateral Deposits.

Note 4 Income Taxes

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

	Nine Months Ended June 30, 2012	Nine Months Ended June 30, 2011
Current Income Taxes		
Federal	$	$ (1,825)
State	6,878	2,703
Deferred Income Taxes		
Federal	85,910	112,385
State	19,038	27,941
	111,826	141,204
Deferred Investment Tax Credit	(436)	(523)
Total Income Taxes	$ 111,390	$ 140,681
Presented as Follows:		
Other Income	$ (436)	$ (523)
Income Tax Expense	111,826	141,204
Total Income Taxes	$ 111,390	$ 140,681

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

	Nine Months Ended June 30, 2012	Nine Months Ended June 30, 2011
U.S. Income Before Income Taxes	$ 282,665	$ 361,726
Income Tax Expense, Computed at Federal Statutory Rate of 35%	$ 98,933	$ 126,604
Increase (Reduction) in Taxes Resulting from:		
State Income Taxes	16,845	19,919
Miscellaneous	(4,388)	(5,842)
Total Income Taxes	$ 111,390	$ 140,681

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Significant components of the Company s deferred tax liabilities and assets were as follows (in thousands):

	At June 30, 2012	At September 30, 2011
Deferred Tax Liabilities:		
Property, Plant and Equipment	$ 1,227,448	$ 1,062,255
Pension and Other Post-Retirement Benefit Costs	205,684	217,302
Other	68,995	70,389
Total Deferred Tax Liabilities	1,502,127	1,349,946
Deferred Tax Assets:		
Pension and Other Post-Retirement Benefit Costs	(264,080)	(263,606)
Tax Loss Carryforwards	(107,999)	(71,516)
Other	(81,951)	(74,863)
Total Deferred Tax Assets	(454,030)	(409,985)
Total Net Deferred Income Taxes	$ 1,048,097	$ 939,961
Presented as Follows:		
Net Deferred Tax Liability/(Asset) Current	$ (14,727)	$ (15,423)
Net Deferred Tax Liability Non-Current	1,062,824	955,384
Total Net Deferred Income Taxes	$ 1,048,097	$ 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 $32.2 million and $19.1 million for the periods ending June 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 $65.6 million and $65.5 million at June 30, 2012 and September 30, 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 $147.7 million and $144.4 million at June 30, 2012 and September 30, 2011, respectively.

The Company files U.S. federal and various state income tax returns. The Internal Revenue Service (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.

Note 5 Capitalization

Common Stock. During the nine months ended June 30, 2012, the Company issued 442,894 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). In addition, the Company issued 118,523 original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan. The Company also issued 11,705 original issue shares of common stock to the non-employee directors of the Company who receive compensation under the Company s 2009 Non-Employee Director Equity Compensation Plan, as partial consideration for the directors services during the nine months ended June 30, 2012. 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 the nine months ended June 30, 2012, 156,961 shares of common stock were tendered to the Company for such purposes. The Company considers all shares tendered as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law.

Current Portion of Long-Term Debt. Current Portion of Long-Term Debt at June 30, 2012 consists of $250 million of 5.25% notes that mature in March 2013. Current Portion of Long-Term Debt at September 30, 2011 consisted of $150 million of 6.70% notes that matured in November 2011.

Long-Term Debt. On December 1, 2011, the Company issued $500.0 million of 4.90% notes due December 1, 2021. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $496.1 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 million due at the maturity of the Company s 6.70% notes in November 2011.

Note 6 Commitments and Contingencies

Environmental Matters. The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and to comply with regulatory 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.

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

At June 30, 2012, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites (including the former manufactured gas plant site discussed above) will be in the range of $15.5 million to $19.7 million. The minimum estimated liability of $15.5 million, which includes the $14.0 million discussed above, has been recorded in Other Deferred Credits on the Consolidated Balance Sheet at June 30, 2012. The Company expects to recover its environmental clean-up costs through rate recovery.

The Company is currently not aware of any material additional exposure to environmental liabilities. However, changes in environmental regulations, new information or other factors could adversely impact the Company.

Other. The Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations and other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost

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issues, among other things. While these other matters arising in the normal course of business could have a material effect on earnings and cash flows in the period in which they are resolved, an estimate of the possible loss or range of loss, if any, cannot be made at this time.

Note 7 Business Segment Information

The Company reports financial results for 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 data presented in the tables below reflect financial information for the segments and reconciliations to consolidated amounts. As stated in the 2011 Form 10-K, the Company evaluates segment performance based on income before discontinued operations, extraordinary items and cumulative effects of changes in accounting (when applicable). When these items are not applicable, the Company evaluates performance based on net income. There have been no changes in the basis of segmentation nor in the basis of measuring segment profit or loss from those used in the Company s 2011 Form 10-K. As for segment assets, the significant changes from the segment assets disclosed in the 2011 Form 10-K involve the Exploration and Production, Utility, and Pipeline and Storage segments as well as the All Other category. Total Exploration and Production segment assets, Utility segment assets and Pipeline and Storage segment assets have increased by $474.4 million, $28.9 million, and $23.1 million, respectively, during the nine months ended June 30, 2012. The All Other category assets have increased by $35.9 million during the nine months ended June 30, 2012.

Quarter Ended June 30, 2012 (Thousands)

	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$ 117,240	$ 36,631	$ 138,549	$ 35,377	$ 327,797	$ 824	$ 240	$ 328,861
Intersegment Revenues	$ 2,703	$ 22,076	$	$ 579	$ 25,358	$ 4,307	$ (29,665)	$
Segment Profit:								
Net Income (Loss)	$ 5,096	$ 12,627	$ 21,915	$ 923	$ 40,561	$ 2,815	$ (192)	$ 43,184

Nine Months Ended June 30, 2012 (Thousands)

	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$ 622,836	$ 113,976	$ 411,449	$ 161,822	$ 1,310,083	$ 2,784	$ 726	$ 1,313,593
Intersegment Revenues	$ 12,643	$ 64,434	$	$ 1,135	$ 78,212	$ 10,828	$ (89,040)	$
Segment Profit:								
Net Income (Loss)	$ 52,725	$ 35,428	$ 74,422	$ 4,662	$ 167,237	$ 5,557	$ (1,519)	$ 171,275

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Quarter Ended June 30, 2011 (Thousands)

	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$ 146,215	$ 29,933	$ 130,974	$ 71,746	$ 378,868	$ 1,873	$ 238	$ 380,979
Intersegment Revenues	$ 3,475	$ 20,324	$	$ 156	$ 23,955	$ 2,810	$ (26,765)	$
Segment Profit:								
Net Income (Loss)	$ 6,328	$ 4,503	$ 32,784	$ 1,891	$ 45,506	$ 2,713	$ (1,328)	$ 46,891

Nine Months Ended June 30, 2011 (Thousands)

	Utility	Pipeline and Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Revenue from External Customers	$ 750,802	$ 103,115	$ 388,571	$ 246,719	$ 1,489,207	$ 2,895	$ 706	$ 1,492,808
Intersegment Revenues	$ 14,680	$ 60,838	$	$ 156	$ 75,674	$ 7,026	$ (82,700)	$
Segment Profit:								
Net Income (Loss)	$ 62,399	$ 24,036	$ 93,455	$ 9,122	$ 189,012	$ 34,320	$ (2,287)	$ 221,045

Note 8 Retirement Plan and Other Post-Retirement Benefits

Components of Net Periodic Benefit Cost (in thousands):

Three months ended June 30,

	Retirement Plan		Other Post-Retirement Benefits	
	2012	2011	2012	2011
Service Cost	$ 3,551	$ 3,693	$ 1,004	$ 1,069
Interest Cost	10,381	10,669	5,329	5,471
Expected Return on Plan Assets	(14,925)	(14,776)	(7,243)	(7,291)
Amortization of Prior Service Cost	67	147	(534)	(427)
Amortization of Transition Amount			3	135
Amortization of Losses	9,904	8,718	6,014	5,948
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) (1)	(2,252)	(2,346)	718	1,602
	$ 6,726	$ 6,105	$ 5,291	$ 6,507

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Nine months ended June 30,

	Retirement Plan		Other Post-Retirement Benefits	
	2012	2011	2012	2011
Service Cost	$ 10,652	$ 11,079	$ 3,012	$ 3,207
Interest Cost	31,144	32,007	15,986	16,413
Expected Return on Plan Assets	(44,776)	(44,328)	(21,728)	(21,873)
Amortization of Prior Service Cost	202	441	(1,604)	(1,282)
Amortization of Transition Amount			8	405
Amortization of Losses	29,711	26,155	18,043	17,845
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) (1)	(1,896)	(584)	7,993	9,564
Net Periodic Benefit Cost	$ 25,037	$ 24,770	$ 21,710	$ 24,279

(1) The Company s policy is to record retirement plan and other post-retirement benefit costs in the Utility segment on a volumetric basis to reflect the fact that the Utility segment experiences higher throughput of natural gas in the winter months and lower throughput of natural gas in the summer months.

Employer Contributions. During the nine months ended June 30, 2012, the Company contributed $31.8 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $18.9 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2012, the Company expects to contribute $12.2 million to the Retirement Plan. 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 fiscal 2012 in order to be in compliance with the Pension Protection Act of 2006. In the remainder of 2012, the Company expects to contribute between $2.0 million and $3.0 million to its VEBA trusts and 401(h) accounts.

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 the provisions of the Act.

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

OVERVIEW

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

The Company is a diversified energy holding company that owns a number of subsidiary operating companies, and reports financial results in four reportable business segments. For the quarter ended June 30, 2012 compared to the quarter ended June 30, 2011, the Company experienced a decrease in earnings of $3.7 million. The earnings decrease for the quarter is primarily due to lower earnings in the Exploration and Production segment, Utility segment, and Energy Marketing segment, partially offset by higher earnings in the Pipeline and Storage segment. For the nine months ended June 30, 2012 compared to the nine months ended June 30, 2011, the Company experienced a decrease in earnings of $49.7 million. The earnings decrease for the nine-month period was primarily driven by 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 nine months ended June 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 generated and sold 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 for the nine-month period, 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 from development 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. Natural gas proved developed and undeveloped reserves in the Appalachian region increased from 331 Bcf at September 30, 2010 to 607 Bcf at September 30, 2011. The Company has spent significant amounts of capital in this region related to the development of such reserves. For the nine months ended June 30, 2012, the Company spent $500.4 million 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 some significant changes to the Company s near term plans. First of all, the Company has announced a reduction in drilling activity under its Marcellus Shale joint venture agreement with EOG Resources, Inc. Along with this change, the Company has reduced its estimated capital expenditures in the Appalachian region to $382.5 million for fiscal 2013. Forecasted production in the Appalachian region for fiscal 2013 has been reduced from a range of 80 to 93 Bcfe to a range of 72 to 83 Bcfe.

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 planned 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. Service for the Northern Access expansion project is expected to begin in November 2012. These projects, which are discussed more completely 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. 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 entered into an Amended and Restated Credit Agreement that replaced the Company s $300.0 million committed credit facility with a similar committed credit facility totaling $750.0 million that extends to January 6, 2017.

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The possibility of environmental risks associated with a well completion technology referred to as hydraulic fracturing 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. For example, New York State had a moratorium in place that prevented hydraulic fracturing of new horizontal wells in the Marcellus Shale. The moratorium ended in July 2011 and the NYDEC has issued its recommendations for shale development and production. However, the recommendations have not gone into effect to date. Due to the small amount of Marcellus Shale acreage owned by the Company in New York State, the final outcome of the NYDEC s recommendations are not expected to have a significant impact on the Company s plans for Marcellus Shale development. Please refer to the Risk Factors section of the Form 10-K for the year ended September 30, 2011 for further discussion.

CRITICAL ACCOUNTING ESTIMATES

For a complete discussion of critical accounting estimates, refer to Critical Accounting Estimates in Item 7 of the Company s 2011 Form 10-K and Item 2 of the Company s December 31, 2011 and March 31, 2012 Form 10-Qs. There have been no material changes to those disclosures other than as set forth below. The information presented below updates and should be read in conjunction with the critical accounting estimates in those documents.

Oil and Gas Exploration and Development Costs. The Company, in its Exploration and Production segment, follows the full cost method of accounting for determining the book value of its oil and natural gas properties. In accordance with this methodology, the Company is required to perform a quarterly ceiling test. Under the ceiling test, the present value of future revenues from the Company s oil and gas reserves based on an unweighted arithmetic average of the first day of the month oil and gas prices for each month within the twelve-month period prior to the end of the reporting period (the ceiling) is compared with the book value of the Company s oil and gas properties at the balance sheet date. If the book value of the oil and gas properties exceeds the ceiling, a non-cash impairment charge must be recorded to reduce the book value of the oil and gas properties to the calculated ceiling. At June 30, 2012, the ceiling exceeded the book value of the oil and gas properties by approximately $107.0 million. The 12-month average of the first day of the month price for crude oil for each month during the twelve months ended June 30, 2012, based on posted Midway Sunset prices, was $106.03 per Bbl. The 12-month average of the first day of the month price for natural gas for each month during the twelve months ended June 30, 2012, based on the quoted Henry Hub spot price for natural gas, was $3.15 per MMBtu. (Note Because actual pricing of the Company s various producing properties varies depending on their location and hedging, the actual various prices received for such production is utilized to calculate the ceiling, rather than the Midway Sunset and Henry Hub prices, which are only indicative of 12-month average prices for the twelve months ended June 30, 2012.) If natural gas average prices used in the ceiling test calculation at June 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 $65.8 million, which would have resulted in an impairment charge. If crude oil average prices used in the ceiling test calculation at June 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 $60.7 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 June 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 $111.6 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. For a more complete discussion of the full cost method of accounting, refer to Oil and Gas Exploration and Development Costs under Critical Accounting Estimates in Item 7 of the Company s 2011 Form 10-K.

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RESULTS OF OPERATIONS

Earnings

The Company s earnings were $43.2 million for the quarter ended June 30, 2012 compared with earnings of $46.9 million for the quarter ended June 30, 2011. The decrease in earnings of $3.7 million is primarily a result of lower earnings in the Exploration and Production segment, Utility segment and Energy Marketing segment. Higher earnings in the Pipeline and Storage segment and the All Other category, as well as a lower loss in the Corporate category partially offset these decreases.

The Company s earnings were $171.3 million for the nine months ended June 30, 2012 compared to earnings of $221.0 million for the nine months ended June 30, 2011. The decrease in earnings of $49.7 million is primarily a 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 partially offset these decreases. The Company s earnings for the nine months ended June 30, 2011 include 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, as discussed above.

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

Earnings (Loss) by Segment

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2012	2011	Increase (Decrease)	2012	2011	Increase (Decrease)
Utility	$ 5,096	$ 6,328	$ (1,232)	$ 52,725	$ 62,399	$ (9,674)
Pipeline and Storage	12,627	4,503	8,124	35,428	24,036	11,392
Exploration and Production	21,915	32,784	(10,869)	74,422	93,455	(19,033)
Energy Marketing	923	1,891	(968)	4,662	9,122	(4,460)
Total Reportable Segments	40,561	45,506	(4,945)	167,237	189,012	(21,775)
All Other	2,815	2,713	102	5,557	34,320	(28,763)
Corporate	(192)	(1,328)	1,136	(1,519)	(2,287)	768
Total Consolidated	$ 43,184	$ 46,891	$ (3,707)	$ 171,275	$ 221,045	$ (49,770)

Utility

Utility Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2012	2011	Increase (Decrease)	2012	2011	Increase (Decrease)
Retail Sales Revenues:						
Residential	$ 82,738	$ 105,001	$ (22,263)	$ 438,409	$ 545,786	$ (107,377)
Commercial	9,262	12,474	(3,212)	55,115	73,833	(18,718)
Industrial	1,005	807	198	3,703	4,951	(1,248)
	93,005	118,282	(25,277)	497,227	624,570	(127,343)

Transportation	24,850	25,016	(166)	102,938	105,380	(2,442)
Off-System Sales		3,976	(3,976)	27,010	29,564	(2,554)
Other	2,088	2,416	(328)	8,304	5,968	2,336
	$ 119,943	$ 149,690	$ (29,747)	$ 635,479	$ 765,482	$ (130,003)

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Utility Throughput

(MMcf)	Three Months Ended June 30, 2012	2011	Increase (Decrease)	Nine Months Ended June 30, 2012	2011	Increase (Decrease)
Retail Sales:						
Residential	7,543	8,867	(1,324)	43,476	54,075	(10,599)
Commercial	954	1,203	(249)	6,109	8,044	(1,935)
Industrial	168	79	89	456	618	(162)
	8,665	10,149	(1,484)	50,041	62,737	(12,696)
Transportation	12,016	12,335	(319)	51,663	57,916	(6,253)
Off-System Sales		867	(867)	9,544	6,188	3,356
	20,681	23,351	(2,670)	111,248	126,841	(15,593)

Degree Days

	Normal	2012	2011	Percent Colder (Warmer) Than Normal[1]	Prior Year[1]
Three Months Ended June 30					
Buffalo	927	751	848	(19.0)	(11.4)
Erie	885	751	814	(15.1)	(7.7)
Nine Months Ended June 30					
Buffalo	6,551	5,171	6,674	(21.1)	(22.5)
Erie	6,142	4,875	6,286	(20.6)	(22.4)

(1) Percents compare actual 2012 degree days to normal degree days and actual 2012 degree days to actual 2011 degree days.

2012 Compared with 2011

Operating revenues for the Utility segment decreased $29.7 million for the quarter ended June 30, 2012 as compared with the quarter ended June 30, 2011. This decrease largely resulted from a $25.3 million decrease in retail gas sales revenues. The decrease in retail gas sales revenues was primarily 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 revenues). The recovery of lower gas costs resulted from lower volumes sold combined with a lower cost of purchased gas. The Utility segment s average cost of purchased gas, including the cost of transportation and storage, was $4.46 per Mcf for the three months ended June 30, 2012, a decrease of 30.6% from the average cost of $6.43 per Mcf for the three months ended June 30, 2011.

Off-system sales decreased from $4.0 million during the quarter ended June 30, 2011 to zero during the quarter ended June 30, 2012. The lack of off-system sales during the quarter ended June 30, 2012 is a 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. 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.

Operating revenues for the Utility segment decreased $130.0 million for the nine months ended June 30, 2012 as compared with the nine months ended June 30, 2011. This decrease largely resulted from a $127.3 million decrease in retail gas sales revenues. The decrease in retail gas sales revenues was primarily 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 revenues). The recovery of lower gas costs resulted from lower volumes sold combined with a lower cost of purchased gas. The Utility segment s average cost of purchased gas, including the cost of transportation and storage, was $5.03 per Mcf for the nine months ended June 30, 2012, a decrease of 19.6% from the average cost of $6.26 per Mcf for the nine months ended June 30, 2011.

The decrease in off-system sales revenues of $2.6 million for the nine months ended June 30, 2012 is primarily a result of the change in gas purchase strategy discussed above for the quarter ending June 30, 2012. Prior to the quarter ending June 30, 2012, off-system sales revenues and volumes had increased over the prior year. 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 decrease in transportation revenues of $2.4 million for the nine months ended June 30, 2012 is primarily due to a 6.3 Bcf decrease in throughput (primarily due to warmer weather). The decrease in transportation revenues was partially offset by a migration of customers from retail sales to transportation services. The $2.3 million increase in other operating revenues for the nine months ended June 30, 2012 was largely attributable to a regulatory adjustment to increase a previous undercollection of pension and other post-retirement benefit costs.

The Utility segment s earnings for the quarter ended June 30, 2012 were $5.1 million, a decrease of $1.2 million when compared with earnings of $6.3 million for the quarter ended June 30, 2011. The decrease in earnings is largely attributable to warmer weather ($2.3 million). In addition, earnings were negatively impacted by higher depreciation of $0.7 million and higher income tax expense of $0.8 million. The increase in depreciation was largely due to depreciation adjustments for certain assets. The increase in income tax expense was largely due to higher state income tax and a provision to return adjustment recorded in 2012. These decreases were partially offset by lower operating expenses of $0.8 million, lower property, franchise and other taxes of $0.3 million, higher usage per account of $0.7 million and the positive earnings impact of lower interest expense of $0.4 million (largely due to lower interest on deferred gas costs). The phrase usage per account refers to average gas consumption per account after factoring out any impact that weather may have had on consumption. The decrease in operating expenses was due to various cost-saving measures. 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 New York jurisdiction is mitigated by that jurisdiction s weather normalization clause (WNC). The WNC in New York, which covers the eight-month period from October through May, has had a stabilizing effect on earnings for the New York rate jurisdiction. In addition, in periods of colder than normal weather, the WNC benefits the Utility segment s New York customers. For the quarter ended June 30, 2012, the WNC preserved earnings of approximately $1.2 million, as the weather was warmer than normal. For the quarter ended June 30, 2011, the WNC reduced earnings by $0.2 million, as it was colder than normal.

The Utility segment s earnings for the nine months ended June 30, 2012 were $52.7 million, a decrease of $9.7 million when compared with earnings of $62.4 million for the nine months ended June 30, 2011. The decrease in earnings is largely attributable to warmer weather ($10.0 million). In addition, earnings were negatively impacted by higher depreciation of $1.0 million (as a result of the adjustments discussed above), regulatory true-up adjustments of $0.9 million associated with the Lower Income Residential Assistance Program and higher income tax expense of $1.4 million (as a result of higher state income tax and a provision to return adjustment recorded in 2012). These decreases were partially offset by lower property, franchise and other taxes of $0.7 million, higher usage per account of $0.9 million and the positive earnings impact of lower interest expense of $1.1 million (largely due to lower interest on deferred gas costs). 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).

For the nine months ended June 30, 2012, the WNC preserved earnings of approximately $5.9 million, as the weather was warmer than normal. For the nine months ended June 30, 2011, the WNC reduced earnings by $1.0 million, as it was colder than normal.

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Pipeline and Storage

Pipeline and Storage Operating Revenues

(Thousands)	Three Months Ended June 30, 2012	2011	Increase (Decrease)	Nine Months Ended June 30, 2012	2011	Increase (Decrease)
Firm Transportation	$ 40,065	$ 31,208	$ 8,857	$ 124,204	$ 103,448	$ 20,756
Interruptible Transportation	318	305	13	1,056	1,035	21
	40,383	31,513	8,870	125,260	104,483	20,777
Firm Storage Service	17,226	16,629	597	50,408	50,090	318
Interruptible Storage Service	7		7	7	19	(12)
Other	1,091	2,115	(1,024)	2,735	9,361	(6,626)
	$ 58,707	$ 50,257	$ 8,450	$ 178,410	$ 163,953	$ 14,457

Pipeline and Storage Throughput

(MMcf)	Three Months Ended June 30, 2012	2011	Increase (Decrease)	Nine Months Ended June 30, 2012	2011	Increase (Decrease)
Firm Transportation	79,921	53,326	26,595	281,579	266,545	15,034
Interruptible Transportation	247	489	(242)	1,511	1,709	(198)
	80,168	53,815	26,353	283,090	268,254	14,836

2012 Compared with 2011

Operating revenues for the Pipeline and Storage segment increased $8.5 million in the quarter ended June 30, 2012 as compared with the quarter ended June 30, 2011. The increase was primarily due to an increase in transportation revenues of $8.9 million, 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 proposed rate case settlement. The rate case and proposed settlement are discussed further in the Rate and Regulatory Matters section. These increases more than offset a reduction in transportation revenues due to the turnback of other pipeline capacity at Niagara. The increase in transportation and storage revenues were partially offset by a decrease in efficiency gas revenues of $1.2 million (reported as a part of other revenue in the table above) resulting from lower natural gas prices and lower efficiency gas volumes. 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 need 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 proposed rate settlement mentioned above, Supply Corporation implemented a tracking mechanism, thus eliminating the impact efficiency gas had to revenues and earnings prior to the proposed rate settlement.

Operating revenues for the Pipeline and Storage segment for the nine months ended June 30, 2012 increased $14.5 million as compared with the nine months ended June 30, 2011. The increase was primarily due to an increase in transportation revenues of $20.8 million, which was primarily the result of new contracts for transportation service on Supply Corporation s Line N Expansion Project and Empire s Tioga County

Extension Project, as discussed above, which more than offset a decline in transportation revenues due to the turnback of other pipeline capacity at Niagara. The increase in transportation revenues was partially offset by a decrease in efficiency gas revenues of $6.8 million 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 nine months ended June 30, 2012. To a lesser extent, the variations reflect the impact of implementing a proposed rate settlement in May 2012. As discussed above for the quarter, the proposed settlement resulted in higher transportation and storage rates and established a tracking mechanism for gas retained from customers.

Transportation volumes for the quarter ended June 30, 2012 increased by 26.4 Bcf from the prior year s quarter. For the nine months ended June 30, 2012, transportation volumes increased by 14.8 Bcf from the prior year s nine-month period. The large increase in transportation volumes for the quarter primarily reflects an increase in deliveries for power generation on Empire s system. On a year-to-date basis, higher transportation volumes for power generation on Empire s system during the quarter ended June 30, 2012 more than offset lower transportation volumes experienced by both Supply Corporation and Empire during the first six months of the fiscal year due to warmer weather during the fall and winter. 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.

The Pipeline and Storage segment s earnings for the quarter ended June 30, 2012 were $12.6 million, an increase of $8.1 million when compared with earnings of $4.5 million for the quarter ended June 30, 2011. The increase in earnings is primarily due to the earnings impact of higher transportation revenues of $5.8 million, as discussed above, combined with lower operating expenses ($2.1 million) and a lower effective tax rate ($0.8 million). 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, a gain on disposal of property, plant and equipment in the current quarter versus the write-off of expired and unused storage rights in the prior-year quarter 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 proposed rate settlement. Absent significant changes in actuarial assumptions, it is expected that Supply Corporation will have lower post-retirement benefit costs under this proposed settlement. The proposed settlement does not include a tracking mechanism related to post-retirement benefit costs. The lower effective tax rate was due to a return to provision adjustment in the current quarter. The earnings increases were partially offset by the earnings impact associated with lower efficiency gas revenues ($0.8 million), as discussed above.

The Pipeline and Storage segment s earnings for the nine months ended June 30, 2012 were $35.4 million, an increase of $11.4 million when compared with earnings of $24.0 million for the nine months ended June 30, 2011. The increase in earnings is primarily due to the earnings impact of higher transportation revenues of $13.5 million, lower operating expenses ($2.0 million) and a lower effective tax rate ($1.0 million), all of which are discussed above, combined with an increase in the allowance for funds used during construction (equity component) of $0.7 million mainly due to construction during the nine months ended June 30, 2012 on Supply Corporation s Northern Access Expansion Project, Line N 2012 Expansion Project and Empire s Tioga County Extension Project. These earnings increases were partially offset by the earnings impact associated with lower efficiency gas revenues ($4.4 million), as discussed above, and higher depreciation expense ($1.1 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 proposed rate case settlement.

Exploration and Production

Exploration and Production Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2012	2011	Increase (Decrease)	2012	2011	Increase (Decrease)
Gas (after Hedging)	$ 69,943	$ 70,849	$ (906)	$ 201,655	$ 202,114	$ (459)
Oil (after Hedging)	64,664	56,058	8,606	198,056	176,088	21,968
Gas Processing Plant	5,966	7,379	(1,413)	19,212	20,721	(1,509)
Other	(50)	337	(387)	108	265	(157)
Intrasegment Elimination [1]	(1,974)	(3,649)	1,675	(7,582)	(10,617)	3,035
	$ 138,549	$ 130,974	$ 7,575	$ 411,449	$ 388,571	$ 22,878

(1) Represents the elimination of certain West Coast gas production revenue included in Gas (after Hedging) in the table above that was 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.

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Production Volumes	Three Months Ended June 30, 2012	2011	Increase (Decrease)	Nine Months Ended June 30, 2012	2011	Increase (Decrease)
Gas Production *(MMcf)*						
Appalachia	16,778	12,090	4,688	43,125	31,020	12,105
West Coast	1,025	826	199	2,670	2,616	54
Gulf Coast		22	(22)		4,092	(4,092)
Total Production	17,803	12,938	4,865	45,795	37,728	8,067
Oil Production *(Mbbl)*						
Appalachia	11	13	(2)	29	35	(6)
West Coast	710	661	49	2,136	1,958	178
Gulf Coast [1]		(9)	9		187	(187)
Total Production	721	665	56	2,165	2,180	(15)

(1) The sale of Gulf Coast properties in April 2011 and various adjustments to prior months production resulted in negative oil production.

Average Prices

	Three Months Ended June 30, 2012	2011	Increase (Decrease)	Nine Months Ended June 30, 2012	2011	Increase (Decrease)
Average Gas Price/Mcf						
Appalachia	$ 2.14	$ 4.55	$ (2.41)	$ 2.70	$ 4.36	$ (1.66)
West Coast	$ 2.97	$ 4.87	$ (1.90)	$ 3.74	$ 4.40	$ (0.66)
Gulf Coast	N/M	N/M	N/M	N/M	$ 5.02	N/M
Weighted Average	$ 2.19	$ 4.67	$ (2.48)	$ 2.76	$ 4.44	$ (1.68)
Weighted Average After Hedging	$ 3.93	$ 5.48	$ (1.55)	$ 4.40	$ 5.36	$ (0.96)
Average Oil Price/Bbl						
Appalachia	$ 95.43	$ 92.89	$ 2.54	$ 94.24	$ 87.36	$ 6.88
West Coast	$ 104.24	$ 108.30	$ (4.06)	$ 108.56	$ 94.74	$ 13.82
Gulf Coast	N/M	N/M	N/M	N/M	$ 88.57	N/M
Weighted Average	$ 104.11	$ 107.97	$ (3.86)	$ 108.37	$ 94.10	$ 14.27
Weighted Average After Hedging	$ 89.70	$ 84.37	$ 5.33	$ 91.50	$ 80.78	$ 10.72

2012 Compared with 2011

Operating revenues for the Exploration and Production segment increased $7.6 million for the quarter ended June 30, 2012 as compared with the quarter ended June 30, 2011. Oil production revenue after hedging increased $8.6 million, largely due to a $5.33 per Bbl increase in the weighted average price of crude oil after hedging coupled with an increase in production. A $0.9 million decrease in natural gas production revenue partially offset this increase. The decrease in natural gas production revenue was due to a $1.55 per Mcf decrease in the weighted average price of natural gas after hedging, offset substantially by an increase in Appalachian natural gas production. The increase in Appalachian production was primarily due to increased development within the Marcellus Shale formation, mainly in Tioga County, Pennsylvania with additional Marcellus Shale production from Lycoming County, Pennsylvania.

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Operating revenues for the Exploration and Production segment increased $22.9 million for the nine months ended June 30, 2012 as compared with the nine months ended June 30, 2011. Oil production revenue after hedging increased $22.0 million due to an increase in the weighted average price of oil after hedging ($10.72 per Bbl). While oil production increased in the West Coast region, it was more than offset by the decrease in oil production stemming from the sale of this segment s offshore oil and natural gas properties in April 2011. In addition, there was a $1.5 million increase in processing plant revenues (net of eliminations) due to a lower cost of gas used in the West Coast processing plant. Partially offsetting these increases was a $0.5 million reduction in gas production revenue after hedging as increases in Appalachian natural gas production were more than offset by the reduction in the weighted average price of natural gas ($0.96 per Mcf) combined with a decrease in natural gas production resulting from the aforementioned sale in April 2011.

The Exploration and Production segment s earnings for the quarter ended June 30, 2012 were $21.9 million, a decrease of $10.9 million when compared with earnings of $32.8 million for the quarter ended June 30, 2011. This was largely attributable to lower natural gas prices after hedging ($17.9 million). In addition, higher depletion expense ($10.1 million), higher general, administrative and other operating expenses ($1.4 million), higher interest expense ($2.9 million), and higher lease operating expenses ($2.0 million) further reduced earnings. The increase in depletion expense is primarily due to an increase in depletable base (due to increased capital spending in the Appalachian region) and production. Higher personnel costs led to increases in general, administrative and other operating expenses. The increase in lease operating expense is largely attributable to higher transportation, compression, water disposal, equipment rental and repair costs in the Appalachian region. 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). In addition, the $1.7 million accrual of a new impact fee imposed by Pennsylvania in 2012 (retroactively applied to all wells) further reduced earnings. These earnings decreases were partially offset by higher natural gas production ($17.3 million), higher crude oil production ($3.1 million), higher crude oil prices ($2.5 million), and the positive earnings impact of lower income taxes ($1.6 million). The reduction in income taxes was due to changes in state allocation rates.

The Exploration and Production segment s earnings for the nine months ended June 30, 2012 were $74.4 million, a decrease of $19.1 million when compared with earnings of $93.5 million for the nine months ended June 30, 2011. Lower natural gas and crude oil revenues ($24.5 million) due to the sale of the offshore oil and natural gas properties in April 2011 contributed to the decrease in earnings. In the Appalachian and West Coast regions, lower natural gas prices after hedging also decreased earnings ($28.2 million). In addition, earnings were reduced by higher depletion expense ($16.7 million), higher interest expense ($4.4 million), higher lease operating expenses ($4.2 million), and higher general, administrative and other expenses ($3.6 million). The increase in depletion expense is primarily due to an increase in depletable base and production. The long-term debt issuance discussed above led to the increase in interest expense. 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. Higher personnel costs led to increases in general, administrative and other operating expenses. In addition, the $8.1 million accrual of a new impact fee imposed by Pennsylvania in 2012 (retroactively applied to all wells) further reduced earnings. These earnings decreases were partially offset by higher Appalachian and West Coast natural gas production ($41.5 million), higher Appalachian and West Coast crude oil production ($9.1 million), higher Appalachian and West Coast crude oil prices ($16.0 million), higher processing plant revenues ($1.0 million), and the positive earnings impact of lower property and other taxes ($2.0 million). The reduction in property and other taxes was due to a revision of the California property tax liability in January 2011, which led to an increase in West Coast property taxes in 2011 that did not recur in 2012. The sale of the offshore oil and natural gas properties in April 2011 led to a further reduction of property and other taxes.

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Energy Marketing

Energy Marketing Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2012	2011	Decrease	2012	2011	Decrease
Natural Gas (after Hedging)	$ 35,950	$ 71,892	$ (35,942)	$ 162,923	$ 246,825	$ (83,902)
Other	6	10	(4)	34	50	(16)
	$ 35,956	$ 71,902	$ (35,946)	$ 162,957	$ 246,875	$ (83,918)

Energy Marketing Volume

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2012	2011	Decrease	2012	2011	Decrease
Natural Gas (MMcf)	10,818	13,508	(2,690)	38,857	45,863	(7,006)

2012 Compared with 2011

Operating revenues for the Energy Marketing segment decreased $35.9 million and $83.9 million for the quarter and nine months ended June 30, 2012, as compared with the quarter and nine months ended June 30, 2011. The decrease for both the quarter and nine months ended June 30, 2012 reflects a decline in gas sales revenue due to a lower average price of natural gas and a decrease in volume sold. Warmer weather is primarily responsible for the decrease in volume.

The Energy Marketing segment s earnings for the quarter ended June 30, 2012 were $0.9 million, a decrease of $1.0 million when compared with earnings of $1.9 million for the quarter ended June 30, 2011. The Energy Marketing segment s earnings for the nine months ended June 30, 2012 were $4.7 million, a decrease of $4.4 million when compared with earnings of $9.1 million for the nine months ended June 30, 2011. These decreases were largely attributable to a decline in margin of $0.9 million and $4.3 million for the quarter and nine-month periods, respectively. The decrease in margin was 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.

Corporate and All Other

2012 Compared with 2011

Corporate and All Other operations recorded earnings of $2.6 million for the quarter ended June 30, 2012, an increase of $1.2 million when compared with earnings of $1.4 million for the quarter ended June 30, 2011. The increase in earnings is primarily due to higher interest income of $2.5 million, lower property, franchise and other taxes of $0.7 million, higher gathering and processing revenues of $1.1 million and lower operating expenses of $0.3 million. 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. The higher interest income is due to higher interest collected from the Company s Exploration and Production segment as a result of their share of these borrowings. The increase in gathering and processing revenues are due to Midstream Corporation s increase in gathering operations for Marcellus Shale gas in Tioga County and Lycoming County, both of which are in Pennsylvania (due to the Trout Run Gathering System being placed into service in May 2012). The decrease in operating expenses is largely due to various cost-saving measures and lower compensation costs. The factors contributing to the overall increase in earnings were partially offset by higher interest expense of $2.4 million, lower margins of $0.7 million and higher depreciation expense of $0.2 million (largely due to an increase in capital spending in the gathering operations). The higher interest expense is due to the borrowings discussed above. The lower margins are due to a decrease in revenues from the sale of standing timber.

For the nine months ended June 30, 2012, Corporate and All Other operations had earnings of $4.0 million, a decrease of $28.0 million when compared with earnings of $32.0 million for the nine months ended June 30, 2011. The decrease in earnings is primarily a reflection of 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. In addition, higher interest expense of $4.0 million and higher depreciation expense of $0.2 million (due to an increase in capital spending in gathering operations) further decreased earnings. The higher interest expense is due to the borrowings as discussed above. The factors contributing to the overall decrease in earnings were partially offset by higher interest income of $4.4 million, higher gathering and processing revenues of $2.4 million, lower property, franchise and other taxes of $0.7 million, lower operating expenses of $0.5 million, higher margins of $0.3 million and a lower loss from unconsolidated subsidiaries of $0.3 million. The higher interest income is due to higher interest collected from the Company s Exploration and Production segment as a result of their share of the borrowing discussed above. The higher margins are 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 Tioga County and Lycoming County, as mentioned above. The lower loss from unconsolidated subsidiaries is primarily due to the non-recurrence of renewable energy credit adjustments recorded by Seneca Energy and Model City during the quarter ended December 31, 2010. Seneca Energy and Model City were sold in February 2011. The decrease in operating expenses is largely due to various cost-saving measures and lower compensation costs.

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

Interest on long-term debt increased $3.7 million for the quarter ended June 30, 2012 as compared with the quarter ended June 30, 2011. For the nine months ended June 30, 2012, interest on long-term debt increased $4.6 million as compared with the nine months ended June 30, 2011. This increase is due to higher borrowings. 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.

Other Interest Expense (amounts below are pre-tax amounts)

Other interest expense decreased $0.3 million for the quarter ended June 30, 2012 as compared with the quarter ended June 30, 2011. For the nine months ended June 30, 2012, other interest expense decreased $1.2 million as compared with the nine months ended June 30, 2011. The decrease is mainly due to lower interest expense on regulatory deferrals (primarily interest on deferred gas costs) in the Utility segment.

CAPITAL RESOURCES AND LIQUIDITY

The Company s primary sources of cash during the nine-month period ended June 30, 2012 consisted of cash provided by operating activities, proceeds from the issuance of long-term debt, net proceeds from short-term borrowings and net proceeds from the issuance of common stock. The Company s primary sources of cash during the nine-month period ended June 30, 2011 consisted of cash provided by operating activities, net proceeds from the sale of unconsolidated subsidiaries and net proceeds from the sale of oil and gas producing properties. During the nine months ended June 30, 2012 and June 30, 2011, the common stock used to fulfill the requirements of the Company s 401(k) plans was obtained via open market purchases. In April 2011, the Company began issuing original issue shares for the Direct Stock Purchase and Dividend Reinvestment Plan.

Operating Cash Flow

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

Cash provided by operating activities in the Utility and Pipeline and Storage segments may vary substantially from period to period because of the impact of rate cases. In the Utility segment, supplier refunds, over- or under-recovered purchased gas costs and weather may also significantly impact cash flow. The impact of weather on cash flow is tempered in the Utility segment s New York rate jurisdiction by its WNC and in the Pipeline and Storage segment by the straight fixed-variable rate design used by Supply Corporation and Empire.

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Because of the seasonal nature of the heating business in the Utility and Energy Marketing segments, revenues in these segments are relatively high during the heating season, primarily the first and second quarters of the fiscal year, and receivable balances historically increase during these periods from the receivable balances at September 30.

The storage gas inventory normally declines during the first and second quarters of the fiscal year and is replenished during the third and fourth quarters. For storage gas inventory accounted for under the LIFO method, the current cost of replacing gas withdrawn from storage is recorded in the Consolidated Statements of Income and a reserve for gas replacement is recorded in the Consolidated Balance Sheets under the caption Other Accruals and Current Liabilities. Such reserve is reduced as the inventory is replenished.

Cash provided by operating activities in the Exploration and Production segment may vary from period to period as a result of changes in the commodity prices of natural gas and crude oil as well as changes in production. The Company uses various derivative financial instruments, including price swap agreements and futures contracts in an attempt to manage this energy commodity price risk.

Net cash provided by operating activities totaled $541.0 million for the nine months ended June 30, 2012, an increase of $4.7 million compared with $536.3 million provided by operating activities for the nine months ended June 30, 2011. The increase in cash provided by operating activities is primarily due to an increase in cash provided by operations in both the Utility segment and Exploration and Production segment, partially offset by a decrease in cash provided by operations in the Energy Marketing segment. The increase in the Utility segment can be attributed to the timing of gas cost recovery. The increase in the Exploration and Production segment reflects higher cash receipts from oil and natural gas production in the West Coast and Appalachian regions combined with hedging collateral account fluctuations, which both offset the loss of cash flow from the Company s former oil and natural gas properties in the Gulf of Mexico. The variation in the Energy Marketing segment can be attributed to lower margins (cash receipts minus cash payments for gas costs), combined with hedging collateral account fluctuations.

Investing Cash Flow

Expenditures for Long-Lived Assets

The Company s expenditures for long-lived assets totaled $803.2 million during the nine months ended June 30, 2012 and $594.7 million for the nine months ended June 30, 2011. The table below presents these expenditures:

Total Expenditures for Long-Lived Assets
Nine Months Ended June 30,

(Millions)	2012	2011	Increase
Utility :			
Capital Expenditures	$ 39.9	$ 39.4	$ 0.5
Pipeline and Storage:			
Capital Expenditures	97.3 (1)(2)	75.0 (3)	22.3
Exploration and Production:			
Capital Expenditures	598.6 (1)(2)	473.5 (3)(4)	125.1
All Other:			
Capital Expenditures	67.4 (1)(2)	6.8	60.6
	$ 803.2	$ 594.7	$ 208.5

(1) Capital expenditures for the Exploration and Production segment include $74.2 million of accrued capital expenditures at June 30, 2012, the majority of which was in the Appalachian region. Capital expenditures for the Pipeline and Storage segment include $8.0 million of accrued capital expenditures at June 30, 2012. In addition, capital expenditures for the All Other category include $16.2 million of accrued capital expenditures at June 30, 2012. These amounts have been excluded from the Consolidated Statement of Cash Flows at June 30, 2012 since they represent non-cash investing activities at that date.

(2) Capital expenditures for the Exploration and Production segment for the nine months ended June 30, 2012 exclude $63.5 million of capital expenditures, the majority of which was in the Appalachian region. Capital expenditures for the Pipeline and Storage segment for the nine months ended June 30, 2012 exclude $7.3 million of capital expenditures. Capital expenditures for the All Other category for the nine months ended June 30, 2012 exclude $1.4 million of capital expenditures. These amounts were accrued at September 30, 2011 and paid during the nine months ended June 30, 2012. These amounts were excluded from the Consolidated Statement of Cash Flows at September 30, 2011 since they represented non-cash investing activities at that date. These amounts have been included in the Consolidated Statement of Cash Flows at June 30, 2012.

(3) Capital expenditures include $60.7 million of accrued capital expenditures for the Exploration and Production segment at June 30, 2011, the majority of which was in the Appalachian region. In addition, capital expenditures for the Pipeline and Storage segment include $5.9 million of accrued capital expenditures at June 30, 2011. These amounts were excluded from the Consolidated Statement of Cash Flows at June 30, 2011 since they represented non-cash investing activities at that date.

(4) Capital expenditures for the Exploration and Production segment for the nine months ended June 30, 2011 exclude $55.5 million of capital expenditures, the majority of which was in the Appalachian region. This amount was accrued at September 30, 2010 and paid during the nine months ended June 30, 2011. This amount was excluded from the Consolidated Statement of Cash Flows at September 30, 2010 since it represented a non-cash investing activity at that date. This amount was included in the Consolidated Statement of Cash Flows at June 30, 2011.

Utility

The majority of the Utility capital expenditures for the nine months ended June 30, 2012 and June 30, 2011 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 the nine months ended June 30, 2012 were related to the construction of Empire s Tioga County Extension Project, Supply Corporation s Line N Expansion Project, Supply Corporation s Line N 2012 Expansion Project and Supply Corporation s Northern Access expansion project, as discussed below. The Pipeline and Storage segment capital expenditures for the nine months ended June 30, 2012 include $20.4 million spent on the Tioga County Extension Project, $2.5 million spent on the Line N Expansion Project, $18.8 million spent on the Line N 2012 Expansion Project, and $24.3 million spent on the Northern Access expansion project. The Pipeline and Storage capital expenditures for the nine months ended June 30, 2012 also include additions, improvements, and replacements to this segment s transmission and gas storage systems. The majority of the Pipeline and Storage capital expenditures for the nine months ended June 30, 2011 were related to additions, improvements, and replacements to this segment s transmission and gas storage systems. In addition, the Pipeline and Storage capital expenditure amounts for the nine months ended June 30, 2011 include $11.8 million spent on the Line N Expansion Project, $7.0 million spent on the Lamont Phase II Project and $11.2 million spent on the Tioga County Extension Project.

In light of the growing demand for pipeline capacity to move natural gas from new wells being drilled in Appalachia specifically in the Marcellus 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 June 30, 2012, the total amount reserved for the Pipeline and Storage segment s preliminary survey and investigation costs was $7.4 million.

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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 its 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. Service is expected to begin in November 2012. The cost estimate for the Northern Access expansion is $75 million. As of June 30, 2012, approximately $26.8 million has been spent on the Northern Access expansion project, all of which has been capitalized as Construction Work in Progress.

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 June 30, 2012, approximately $20.7 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 June 30, 2012.

Supply Corporation has also executed three precedent 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. 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. As of June 30, 2012, approximately $21.2 million has been spent on the Line N 2012 Expansion Project, all of which has been capitalized as Construction Work in Progress.

Supply Corporation continues to market the West-to-East (W2E) pipeline project, which is designed to transport locally produced Marcellus natural gas supplies, principally from the dry central area of the trend, to the Ellisburg/Leidy/Corning area. Supply Corporation anticipates that the development of the W2E project will occur in phases. As currently envisioned, the initial phases of W2E, referred to as the W2E Overbeck to Leidy project, are 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 W2E Overbeck to Leidy project also includes a total of approximately 25,000 horsepower of compression at two separate stations. On March 31, 2010, the FERC granted Supply Corporation s request for a pre-filing environmental review of the W2E Overbeck to Leidy project. Supply Corporation has since withdrawn from the FERC process, which would be restarted upon the development of an adequate market to support the estimated $290 million capital cost of the project. As of June 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 June 30, 2012.

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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 an anchor shipper that would take all 150,000 Dth/day of the capacity on the project. Service is expected to begin in 2014 and the estimated cost is $25 million to $30 million. As of June 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 June 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 $55 million, of which approximately $52.2 million has been spent through June 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 June 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. As of June 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 June 30, 2012.

Exploration and Production

The Exploration and Production segment capital expenditures for the nine months ended June 30, 2012 were primarily well drilling and completion expenditures and included approximately $552.0 million for the Appalachian region (including $500.4 million in the Marcellus Shale area) and $46.6 million for the West Coast region. These amounts included approximately $198.7 million spent to develop proved undeveloped reserves.

The Exploration and Production segment capital expenditures for the nine months ended June 30, 2011 were primarily well drilling and completion expenditures and included approximately $441.2 million for the Appalachian region (including $433.5 million in the Marcellus Shale area), $28.1 million for the West Coast region and $4.2 million for the Gulf Coast region (former offshore oil and natural gas properties in the Gulf of Mexico). These amounts included approximately $165.5 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. The Company funded this transaction with cash from operations.

For all of fiscal 2013, the Company expects to spend $450.0 million on Exploration and Production segment capital expenditures. Previously reported 2013 estimated capital expenditures for the Exploration and Production segment were $500.0 million. In the Appalachian region, estimated capital expenditures will decrease from $442.5 million to $382.5 million. Estimated capital expenditures in the West Coast region will increase from $57.5 million to $67.5 million. The decrease in estimated capital expenditures for the Appalachian region noted above is due to an anticipated reduction in drilling and completion activity associated with a Marcellus Shale joint venture agreement with EOG Resources, Inc. The anticipated reduction in joint venture activity is largely a response to the current low natural gas price environment.

In April 2011, the Company completed the sale of its offshore oil and natural gas properties in the Gulf of Mexico. Initial proceeds received through June 30, 2011 totaled $61.8 million. Price adjustments subsequent to June 30, 2011 reduced the final net proceeds to $55.4 million. Under the full cost method of accounting for oil and 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 in the 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.

All Other

The majority of the All Other category s capital expenditures for the nine months ended June 30, 2012 were for the construction of Midstream Corporation s Trout Run Gathering System and the expansion of Midstream Corporation s Covington Gathering System, as discussed below. The majority of the All Other category s capital expenditures for the nine months ended June 30, 2011 were primarily for the expansion of Midstream Corporation s Covington Gathering system as well as for the construction of Midstream Corporation s Trout Run Gathering System.

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 will include additional in-field gathering pipelines and compression at a cost of approximately $130 million. As of June 30, 2012, the Company has spent approximately $71.7 million in costs related to this project, including approximately $56.2 million spent during the nine months ended June 30, 2012, all of which is included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 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 June 30, 2012, the Company has spent approximately $24.1 million in costs related to the Covington Gathering System, including approximately $7.8 million spent during the nine months ended June 30, 2012. All costs associated with this gathering system are included in Property, Plant and Equipment on the Consolidated Balance Sheet at June 30, 2012.

Midstream Corporation is planning the construction of several smaller gathering systems. As of June 30, 2012, the Company has spent approximately $2.9 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. 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 increase its use of short-term borrowings during fiscal 2012. Natural gas and crude oil prices combined with production from existing wells will be a significant factor in determining how much of the capital expenditures are funded with cash from operations. The Company also issued additional long-term debt in December 2011 to enhance its liquidity position.

The Company continuously evaluates capital expenditures and 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

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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 $30.2 million during the nine months ended June 30, 2012. The maximum amount of short-term debt outstanding during the nine months ended June 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 June 30, 2012, the Company had outstanding commercial paper and short-term notes payable to banks of $50.0 and $20.2 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 June 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 June 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 June 30, 2012, the Company s debt to capitalization ratio (as calculated under the facility) was .42. The constraints specified in the committed credit facility would have permitted an additional $2.22 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 June 30, 2012, the Company would have been permitted to issue up to a maximum of $1.56 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 June 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.

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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 June 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 June 30, 2012 and 6.85% at June 30, 2011.

Current Portion of Long-Term Debt at June 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 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 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 $30.7 million. These leases have been entered into for the use of compressors, buildings, meters and other items and are accounted for as operating leases.

OTHER MATTERS

In addition to the legal proceedings disclosed in Part II, Item 1 of this report, the Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations or other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service and purchased gas cost issues, among other things. While these normal-course matters could have a material effect on earnings and cash flows in the quarterly and annual period in which they are resolved, they are not expected to change materially the Company s present liquidity position, nor are they expected to have a material adverse effect on the financial condition of the Company.

During the nine months ended June 30, 2012, the Company contributed $31.8 million to its Retirement Plan and $18.9 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2012, the Company expects to contribute $12.2 million to the Retirement Plan.

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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 fiscal 2012 in order to be in compliance with the Pension Protection Act of 2006. In the remainder of 2012, the Company expects to contribute between $2.0 million and $3.0 million to its VEBA trusts and 401(h) accounts.

Market Risk Sensitive Instruments

On July 21, 2010, the Dodd-Frank Act was signed into law. The Dodd-Frank Act includes provisions related to the swaps and over-the-counter derivatives markets. Certain provisions of the Dodd-Frank Act related to derivatives became effective July 16, 2011, but other provisions related to derivatives will not become effective until 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 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-cleared swap that is available as a 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 Net Liabilities amount to $16.5 million at June 30, 2012 and represent 7.6% of the Total Net Assets shown in Part I, Item 1 at Note 2 Fair Value Measurements at June 30, 2012.

The increase in the net fair value liability of the Level 3 positions from October 1, 2011 to June 30, 2012, as shown in Part I, Item 1 at Note 2, was attributable to an increase in the commodity price of crude oil relative to the swap price 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 June 30, 2012.

The fair value of all of the Company s Net Derivative Assets was reduced by $0.5 million at June 30, 2012 based upon the Company s assessment of counterparty credit risk (for the Company s derivative assets) and the Company s credit risk (for the Company s derivative liabilities). 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.

For a complete discussion of market risk sensitive instruments, refer to Market Risk Sensitive Instruments in Item 7 of the Company s 2011 Form 10-K. There have been no subsequent material changes to the Company s exposure to market risk sensitive instruments.

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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 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 April 27, 2012, the FERC accepted the new settled rates to be effective May 1, 2012 on an interim basis, subject to surcharge and refund if the settlement in principle does not become effective.

To become effective, the settlement in principle must be memorialized in a written stipulation approved by the parties, certified by the Administrative Law Judge, and approved by the FERC. On May 22, 2012, Supply Corporation submitted a written Stipulation and Agreement that is supported or not opposed by all intervenors participating in the settlement conferences in the rate case and by the FERC Trial Staff. On June 19, 2012, the Administrative Law Judge certified the Stipulation and Agreement as an uncontested partial settlement. If approved by the FERC, the Stipulation and Agreement resolves or provides procedures for resolving all issues in the rate case.

If no settlement is implemented, and the rates finally approved at the end of the proceeding exceed the rates that were in effect at October 31, 2011 but are less than the rates put into effect subject to refund on May 1, 2012, then Supply Corporation will be required to refund the difference between the rates collected subject to refund and the final approved rates, with interest at the FERC-approved rate. If no

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settlement is implemented, and the rates approved at the end of the proceeding are lower than the rates in effect at October 31, 2011, then the refund obligation will be limited to the difference between the rates in effect at October 31, 2011 and the rates put into effect subject to refund on May 1, 2012, with interest at the FERC-approved rate. To the extent any final FERC-approved rates are below those in effect at October 31, 2011, there is no refund for that rate differential. The final FERC-approved rates would be charged to customers only prospectively, from the date they go into effect.

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 will either justify Empire s existing recourse rates or 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.

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

At June 30, 2012, the Company has estimated its remaining clean-up costs related to former manufactured gas plant sites and third party waste disposal sites (including the former manufactured gas plant site discussed above) will be in the range of $15.5 million to $19.7 million. The minimum estimated liability of $15.5 million, which includes the $14.0 million discussed above, has been recorded in Other Deferred Credits on the Consolidated Balance Sheet at June 30, 2012. The Company expects to recover its environmental clean-up costs through rate recovery.

Legislative and regulatory measures to address climate change and greenhouse gas emissions are in various phases of discussion or implementation. Pursuant to an EPA determination, effective January 2011 projects proposing new stationary sources of significant greenhouse gas emissions or major modifications of existing facilities are required under the federal Clean Air Act to obtain permits covering such emissions. The EPA is also considering other regulatory options to regulate greenhouse gas emissions from the energy industry. In April 2011, the U.S. Senate rejected bills aimed at curbing the authority of the EPA to regulate greenhouse gas emissions. 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.

The Company is currently not aware of any material additional exposure to environmental liabilities. However, changes in environmental regulations, new information or other factors could adversely impact the Company.

New Authoritative Accounting and Financial Reporting Guidance

In May 2011, the FASB issued authoritative guidance regarding fair value measurement as a joint project with the IASB. The objective of the guidance was to bring together as closely as possible the fair value measurement and disclosure guidance issued by the two boards. The guidance includes a few updates to measurement guidance and some enhanced disclosure requirements. For all Level 3 fair value measurements, the guidance requires quantitative information about significant unobservable inputs used and a description of the valuation processes in place. The guidance also requires a qualitative discussion about the sensitivity of recurring Level 3 fair value measurements and information about any transfers between Level 1 and Level 2 of the fair value hierarchy. The new guidance also contains a requirement that all fair value measurements, whether they are recorded on the balance sheet or disclosed in the footnotes, be classified as Level 1, Level 2 or Level 3 within the fair value hierarchy. This authoritative guidance became effective for the quarter ended March 31, 2012. The Company has updated its disclosures to reflect the new requirements in Item 1 at Note 2 Fair Value Measurements.

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 results of operations.

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. While early adoption is permitted, the Company has not adopted the new provisions to date.

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.

Safe Harbor for Forward-Looking Statements

The Company is including the following cautionary statement in this Form 10-Q to make applicable and take advantage of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995 for any forward-looking statements made by, or on behalf of, the Company. Forward-looking statements include statements concerning plans, objectives, goals, projections, strategies, future events or performance, and underlying assumptions and other statements which are other than statements of historical facts. From time to time, the Company may publish or otherwise make available forward-looking statements of this nature. All such subsequent forward-looking statements, whether written or oral and whether made by or on behalf of the Company, are also expressly qualified by these cautionary statements. Certain statements contained in this report, including, without limitation, statements regarding future prospects, plans, objectives, goals, projections, estimates of oil and gas quantities, strategies, future events or performance and underlying assumptions, capital structure, anticipated capital expenditures, completion of construction projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words anticipates, estimates, expects, forecasts, intends, plans, predicts, projects, believes, seeks 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;

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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 3. Quantitative and Qualitative Disclosures About Market Risk

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

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

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

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 June 30, 2012 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

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

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 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, 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 1A. Risk Factors

The risk factors in Item 1A of the Company s 2011 Form 10-K, as amended by Item 1A of Part II of the Company s Forms 10-Q for the quarters ended December 31, 2011 and March 31, 2012, have not materially changed.

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

On April 2, 2012, the Company issued a total of 3,600 unregistered shares of Company common stock to the eight non-employee directors of the Company then serving on the Board of Directors of the Company, 450 shares to each such director. On June 7, 2012, the Company issued 119 unregistered shares of Company common stock to David C. Carroll, who joined the Board that day as a non-employee director. All of these unregistered shares were issued under the Company s 2009 Non-Employee Director Equity Compensation Plan as partial consideration for such directors services during the quarter ended June 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]
Apr. 1 - 30, 2012	8,165	$ 45.50		6,971,019
May 1 - 31, 2012	7,825	$ 45.37		6,971,019
June 1 - 30, 2012	9,622	$ 44.51		6,971,019
Total	25,612	$ 45.09		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 June 30, 2012, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program. Of the 25,612 shares purchased other than through a publicly announced share repurchase program, 24,113 were purchased for the Company s 401(k) plans and 1,499 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 Company, however, stopped repurchasing shares after September 17, 2008. Since that time, the Company has increased its emphasis on Marcellus Shale development and pipeline expansion. As such, the Company does not anticipate repurchasing any shares in the near future.

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Item 6. **Exhibits**

Exhibit Number	Description of Exhibit
	Form of Indemnification Agreement between the Company and David C. Carroll, Director (Exhibit 10.1, Form 8-K dated September 18, 2006 in File No. 1-3880)
12	Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the Twelve Months Ended June 30, 2012 and the Fiscal Years Ended September 30, 2008 through 2011.
31.1	Written statements of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act.
31.2	Written statements of Principal Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) of the Exchange Act.
32	Certification furnished pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99	National Fuel Gas Company Consolidated Statement of Income for the Twelve Months Ended June 30, 2012 and 2011.
101	Interactive data files submitted pursuant to Regulation S-T: (i) the Consolidated Statements of Income and Earnings Reinvested in the Business for the three and nine months ended June 30, 2012 and 2011, (ii) the Consolidated Balance Sheets at June 30, 2012 and September 30, 2011, (iii) the Consolidated Statements of Cash Flows for the nine months ended June 30, 2012 and 2011, (iv) the Consolidated Statements of Comprehensive Income for the three and nine months ended June 30, 2012 and 2011 and (v) the Notes to Condensed Consolidated Financial Statements.

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

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SIGNATURES

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

NATIONAL FUEL GAS COMPANY
(Registrant)

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

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

Date: August 3, 2012