Table of Contents

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, 2011

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, 2011: 82,726,474 shares.

Table of Contents

GLOSSARY OF TERMS

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

National Fuel Gas Companies	
Company	The Registrant, the Registrant and its subsidiaries or the Registrant s subsidiaries as appropriate in the context of the disclosure
Distribution Corporation	National Fuel Gas Distribution Corporation
Empire	Empire Pipeline, Inc.
ESNE	Energy Systems North East, LLC
Highland	Highland Forest Resources, Inc.
Horizon	Horizon Energy Development, Inc.
Horizon B.V.	Horizon Energy Development B.V.
Horizon LFG	Horizon LFG, Inc.
Horizon Power	Horizon Power, Inc.
Midstream Corporation	National Fuel Gas Midstream Corporation
Model City	Model City Energy, LLC
National Fuel	National Fuel Gas Company
NFR	National Fuel Resources, Inc.
Registrant	National Fuel Gas Company
Seneca	Seneca Resources Corporation
Seneca Energy	Seneca Energy II, LLC
Supply Corporation	National Fuel Gas Supply Corporation
Regulatory Agencies	
EPA	United States Environmental Protection Agency
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
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
SEC	Securities and Exchange Commission
Other	
2010 Form 10-K	The Company s Annual Report on Form 10-K for the year ended September 30, 2010
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 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
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.

GLOSSARY OF TERMS (Cont.)

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 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.
Restructuring	Generally referring to partial deregulation of the pipeline and/or utility industry by a 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.

Table of Contents

GLOSSARY OF TERMS (Concl.)

Revenue decoupling mechanism	A rate mechanism which adjusts customer rates to render a utility financially indifferent to throughput decreases resulting from conservation.
S&P	Standard & Poor s Ratings Service
SAR	Stock appreciation right
Service agreement	The binding agreement by which the pipeline company agrees to provide service and the shipper agrees to pay for the service.
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.

Table of Contents

INDEX

	Page
Part I. Financial Information	
Item 1. Financial Statements (Unaudited)	
a. Consolidated Statements of Income and Earnings Reinvested in the Business Three and Nine Months Ended June 30, 2011 and 2010	5 - 6
b. Consolidated Balance Sheets June 30, 2011 and September 30, 2010	7 - 8
c. Consolidated Statements of Cash Flows Nine Months Ended June 30, 2011 and 2010	9
d. Consolidated Statements of Comprehensive Income Three and Nine Months Ended June 30, 2011 and 2010	10
e. Notes to Condensed Consolidated Financial Statements	11 - 30
Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations	31 - 56
Item 3. Quantitative and Qualitative Disclosures About Market Risk	56
Item 4. Controls and Procedures	56
Part II. Other Information	
Item 1. Legal Proceedings	57
Item 1 A. Risk Factors	57
Item 2. Unregistered Sales of Equity Securities and Use of Proceeds	57
Item 3. Defaults Upon Senior Securities	.
Item 5. Other Information	.
Item 6. Exhibits	58
Signatures	59

. 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.

Table of Contents

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, 2011	2010
INCOME		
Operating Revenues	$ 380,979	$ 351,992
Operating Expenses		
Purchased Gas	112,725	97,195
Operation and Maintenance	95,977	96,593
Property, Franchise and Other Taxes	20,179	18,594
Depreciation, Depletion and Amortization	57,293	50,422
	286,174	262,804
Operating Income	94,805	89,188
Other Income (Expense):		
Income (Loss) from Unconsolidated Subsidiaries	(77)	624
Interest Income	325	568
Other Income	1,890	851
Interest Expense on Long-Term Debt	(17,876)	(21,115)
Other Interest Expense	(1,159)	(1,866)
Income from Continuing Operations Before Income Taxes	77,908	68,250
Income Tax Expense	31,017	25,608
Income from Continuing Operations	46,891	42,642
Loss from Discontinued Operations, Net of Tax		(57)
Net Income Available for Common Stock	46,891	42,585
EARNINGS REINVESTED IN THE BUSINESS		
Balance at April 1	1,180,531	1,038,869
	1,227,422	1,081,454
Dividends on Common Stock (2011 $0.355 per share; 2010 $0.345 per share)	(29,358)	(28,278)
Balance at June 30	$ 1,198,064	$ 1,053,176

Earnings Per Common Share:		
Basic:		
Income from Continuing Operations	$ 0.57	$ 0.52
Loss from Discontinued Operations		
Net Income Available for Common Stock	$ 0.57	$ 0.52
Diluted:		
Income from Continuing Operations	$ 0.56	$ 0.51
Loss from Discontinued Operations		
Net Income Available for Common Stock	$ 0.56	$ 0.51
Weighted Average Common Shares Outstanding:		
Used in Basic Calculation	82,687,467	81,801,377
Used in Diluted Calculation	83,782,493	82,970,921

See Notes to Condensed Consolidated Financial Statements

Table of Contents

Item 1. Financial Statements (Cont.)

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, 2011	Nine Months Ended June 30, 2010
INCOME		
Operating Revenues	$ 1,492,808	$ 1,474,107
Operating Expenses		
Purchased Gas	582,358	601,408
Operation and Maintenance	310,148	306,624
Property, Franchise and Other Taxes	63,714	57,684
Depreciation, Depletion and Amortization	170,617	141,935
	1,126,837	1,107,651
Operating Income	365,971	366,456
Other Income (Expense):		
Income (Loss) from Unconsolidated Subsidiaries	(698)	1,696
Gain on Sale of Unconsolidated Subsidiaries	50,879	
Interest Income	1,277	2,048
Other Income	4,828	2,473
Interest Expense on Long-Term Debt	(55,994)	(65,238)
Other Interest Expense	(4,014)	(5,245)
Income from Continuing Operations Before Income Taxes	362,249	302,190
Income Tax Expense	141,204	115,449
Income from Continuing Operations	221,045	186,741
Income from Discontinued Operations, Net of Tax		771
Net Income Available for Common Stock	221,045	187,512
EARNINGS REINVESTED IN THE BUSINESS		
Balance at October 1	1,063,262	948,293
	1,284,307	1,135,805
Dividends on Common Stock (2011 $1.045 per share; 2010 $1.015 per share)	(86,243)	(82,629)
Balance at June 30	$ 1,198,064	$ 1,053,176

Earnings Per Common Share:		
Basic:		
Income from Continuing Operations	$ 2.68	$ 2.30
Income from Discontinued Operations		0.01
Income Available for Common Stock	$ 2.68	$ 2.31
Diluted:		
Income from Continuing Operations	$ 2.64	$ 2.26
Income from Discontinued Operations		0.01
Income Available for Common Stock	$ 2.64	$ 2.27
Weighted Average Common Shares Outstanding:		
Used in Basic Calculation	82,436,603	81,178,000
Used in Diluted Calculation	83,649,498	82,556,730

See Notes to Condensed Consolidated Financial Statements

Table of Contents

Item 1. Financial Statements (Cont.)

National Fuel Gas Company

Consolidated Balance Sheets

(Unaudited)

(Thousands of Dollars)	June 30, 2011	September 30, 2010
ASSETS		
Property, Plant and Equipment	$ 5,392,065	$ 5,637,498
Less Accumulated Depreciation, Depletion and Amortization	1,607,088	2,187,269
	3,784,977	3,450,229
Current Assets		
Cash and Temporary Cash Investments	184,710	397,171
Hedging Collateral Deposits	37,984	11,134
Receivables Net of Allowance for Uncollectible Accounts of $39,221 and $30,961, Respectively	165,576	132,136
Unbilled Utility Revenue	13,399	20,920
Gas Stored Underground	22,525	48,584
Materials and Supplies at average cost	28,923	24,987
Other Current Assets	44,786	115,969
Deferred Income Taxes	22,885	24,476
	520,788	775,377
Other Assets		
Recoverable Future Taxes	151,142	149,712
Unamortized Debt Expense	11,058	12,550
Other Regulatory Assets	524,355	542,801
Deferred Charges	4,989	9,646
Other Investments	84,118	77,839
Investments in Unconsolidated Subsidiaries	1,367	14,828
Goodwill	5,476	5,476
Fair Value of Derivative Financial Instruments	43,347	65,184
Other	1,648	1,983
	827,500	880,019
Total Assets	$ 5,133,265	$ 5,105,625

See Notes to Condensed Consolidated Financial Statements

Table of Contents

Item 1. Financial Statements (Cont.)

National Fuel Gas Company

Consolidated Balance Sheets

(Unaudited)

(Thousands of Dollars)	June 30, 2011	September 30, 2010
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders Equity		
Common Stock, $1 Par Value Authorized 200,000,000 Shares; Issued and Outstanding 82,700,177 Shares and 82,075,470 Shares, Respectively	$ 82,700	$ 82,075
Paid in Capital	644,945	645,619
Earnings Reinvested in the Business	1,198,064	1,063,262
Total Common Shareholder Equity Before Items of Other Comprehensive Loss	1,925,709	1,790,956
Accumulated Other Comprehensive Loss	(75,098)	(44,985)
Total Comprehensive Shareholders Equity	1,850,611	1,745,971
Long-Term Debt, Net of Current Portion	899,000	1,049,000
Total Capitalization	2,749,611	2,794,971
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper		
Current Portion of Long-Term Debt	150,000	200,000
Accounts Payable	95,182	89,677
Amounts Payable to Customers	25,661	38,109
Dividends Payable	29,358	28,316
Interest Payable on Long-Term Debt	15,953	30,512
Customer Advances	1,021	27,638
Customer Security Deposits	17,672	18,320
Other Accruals and Current Liabilities	133,856	71,592
Fair Value of Derivative Financial Instruments	44,607	20,160
	513,310	524,324
Deferred Credits		
Deferred Income Taxes	919,145	800,758
Taxes Refundable to Customers	70,343	69,585
Unamortized Investment Tax Credit	2,761	3,288
Cost of Removal Regulatory Liability	133,759	124,032
Other Regulatory Liabilities	92,811	89,334
Pension and Other Post-Retirement Liabilities	435,517	446,082
Asset Retirement Obligations	65,583	101,618
Other Deferred Credits	150,425	151,633
	1,870,344	1,786,330

Commitments and Contingencies		
Total Capitalization and Liabilities	$ 5,133,265	$ 5,105,625

See Notes to Condensed Consolidated Financial Statements

Table of Contents

Item 1. Financial Statements (Cont.)

National Fuel Gas Company

Consolidated Statements of Cash Flows

(Unaudited)

(Thousands of Dollars)	Nine Months Ended June 30, 2011	2010
OPERATING ACTIVITIES		
Net Income Available for Common Stock	$ 221,045	$ 187,512
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Gain on Sale of Unconsolidated Subsidiaries	(50,879)	
Depreciation, Depletion and Amortization	170,617	142,433
Deferred Income Taxes	140,326	63,813
(Income) Loss from Unconsolidated Subsidiaries, Net of Cash Distributions	4,976	904
Excess Tax Costs (Benefits) Associated with Stock-Based Compensation Awards	1,224	(13,207)
Other	2,375	7,884
Change in:		
Hedging Collateral Deposits	(26,850)	(7,374)
Receivables and Unbilled Utility Revenue	(25,919)	6,676
Gas Stored Underground and Materials and Supplies	22,387	20,384
Prepayments and Other Current Assets	69,960	39,043
Accounts Payable	5,506	127
Amounts Payable to Customers	(12,448)	(54,764)
Customer Advances	(26,617)	(23,526)
Customer Security Deposits	(648)	1,188
Other Accruals and Current Liabilities	36,743	30,961
Other Assets	20,255	29,197
Other Liabilities	(15,771)	(11,358)
Net Cash Provided by Operating Activities	536,282	419,893
INVESTING ACTIVITIES		
Capital Expenditures	(583,739)	(327,513)
Net Proceeds from Sale of Unconsolidated Subsidiaries	59,365	
Net Proceeds from Sale of Oil and Gas Producing Properties	69,435	
Other	(2,908)	(273)
Net Cash Used in Investing Activities	(457,847)	(327,786)
FINANCING ACTIVITIES		
Excess Tax (Costs) Benefits Associated with Stock-Based Compensation Awards	(1,224)	13,207
Reduction of Long-Term Debt	(200,000)	
Dividends Paid on Common Stock	(85,201)	(81,318)
Net Proceeds from Issuance (Repurchase) of Common Stock	(4,471)	26,798
Net Cash Used in Financing Activities	(290,896)	(41,313)
Net Increase (Decrease) in Cash and Temporary Cash Investments	(212,461)	50,794

Cash and Temporary Cash Investments at October 1	397,171	408,053
Cash and Temporary Cash Investments at June 30	$ 184,710	$ 458,847

See Notes to Condensed Consolidated Financial Statements

Table of Contents

Item 1. Financial Statements (Cont.)

National Fuel Gas Company

Consolidated Statements of Comprehensive Income

(Unaudited)

(Thousands of Dollars)	Three Months Ended June 30, 2011	Three Months Ended June 30, 2010
Net Income Available for Common Stock	$ 46,891	$ 42,585
Other Comprehensive Income, Before Tax:		
Foreign Currency Translation Adjustment		77
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	23	(3,361)
Unrealized Gain on Derivative Financial Instruments Arising During the Period	26,378	16,528
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	3,185	(11,830)
Other Comprehensive Income, Before Tax	29,586	1,414
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	8	(1,271)
Income Tax Expense Related to Unrealized Gain on Derivative Financial Instruments Arising During the Period	10,810	6,794
Reclassification Adjustment for Income Tax Benefit (Expense) on Realized Losses (Gains) on Derivative Financial Instruments in Net Income	1,345	(4,858)
Income Taxes Net	12,163	665
Other Comprehensive Income	17,423	749
Comprehensive Income	$ 64,314	$ 43,334

(Thousands of Dollars)	Nine Months Ended June 30, 2011	Nine Months Ended June 30, 2010
Net Income Available for Common Stock	$ 221,045	$ 187,512
Other Comprehensive Income (Loss), Before Tax:		
Foreign Currency Translation Adjustment	17	140
Reclassification Adjustment for Realized Foreign Currency Transaction Loss in Net Income	34	
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	3,461	(2,916)
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(41,602)	39,308
Reclassification Adjustment for Realized Gains on Derivative Financial Instruments in Net Income	(13,080)	(29,472)
Other Comprehensive Income (Loss), Before Tax	(51,170)	7,060
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	1,306	(1,104)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	(17,136)	16,041

Reclassification Adjustment for Income Tax Expense on Realized Gains on Derivative Financial Instruments in Net Income	(5,227)	(12,120)
Income Taxes Net	(21,057)	2,817
Other Comprehensive Income (Loss)	(30,113)	4,243
Comprehensive Income	$ 190,932	$ 191,755

See Notes to Condensed Consolidated Financial Statements

Table of Contents

Item 1. Financial Statements (Cont.)

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.

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 accrued capital expenditures of $55.5 million from Accounts Payable to Other Accruals and Current Liabilities on the Consolidated Balance Sheet at September 30, 2010. This reclassification did not impact the Consolidated Statement of Income or the Consolidated Statement of Cash Flows for any of the periods presented.

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, 2010, 2009 and 2008 that are included in the Company s 2010 Form 10-K. The consolidated financial statements for the year ended September 30, 2011 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, 2011 should not be taken as a prediction of earnings for the entire fiscal year ending September 30, 2011. 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 8 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, 2011, the Company accrued $60.7 million of capital expenditures in the Exploration and Production segment, the majority of which was in the Appalachian region. The Company also accrued $5.9 million of capital expenditures in the Pipeline and Storage segment at June 30, 2011. These amounts were excluded from the Consolidated Statement of Cash Flows at June 30, 2011 since they represent non-cash investing activities at that date. Accrued capital expenditures at June 30, 2011 are included in Other Accruals and Current Liabilities on the Consolidated Balance Sheet.

At September 30, 2010, the Company accrued $55.5 million of capital expenditures in the Exploration and Production segment, the majority of which was in the Appalachian region. 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. Accrued capital expenditures at September 30, 2010 are included in Other Accruals and Current Liabilities on the Consolidated Balance Sheet.

Table of Contents

Item 1. Financial Statements (Cont.)

At June 30, 2010, the Company accrued $24.3 million of capital expenditures in the Exploration and Production segment, the majority of which was in the Appalachian region. This amount was excluded from the Consolidated Statement of Cash Flows at June 30, 2010 since it represented a non-cash investing activity at that date.

At September 30, 2009, the Company accrued $9.1 million of capital expenditures in the Exploration and Production segment, the majority of which was in the Appalachian region. The Company also accrued $0.7 million of capital expenditures in the All Other category related to the construction of the Midstream Covington Gathering System. These amounts were excluded from the Consolidated Statement of Cash Flows at September 30, 2009 since they represented non-cash investing activities at that date. These capital expenditures were paid during the quarter ended December 31, 2009 and have been included in the Consolidated Statement of Cash Flows for the nine months ended June 30, 2010.

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, 2011, the Company had hedging collateral deposits of $5.6 million related to its exchange-traded futures contracts and $32.4 million related to its over-the-counter crude oil swap agreements. At September 30, 2010, the Company had hedging collateral deposits of $10.1 million related to its exchange-traded futures contracts and $1.0 million related to its over-the-counter crude oil swap agreements. In accordance with its accounting policy, the Company does not offset hedging collateral deposits paid or received against related derivative financial instrument liability or asset balances.

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 $45.0 million at June 30, 2011, 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 $193.9 million and $151.2 million at June 30, 2011 and September 30, 2010, 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.

In March 2011, the Company entered into a purchase and sale agreement to sell its off-shore oil and natural gas properties effective as of January 1, 2011 in the Gulf of Mexico for approximately $70 million and received a deposit of $7.0 million from the purchaser. The Company completed the sale in April 2011, receiving an additional $54.8 million. The difference between the total proceeds received of $61.8 million and the sale price of $70.0 million represents a purchase price adjustment for the operating cash flow that the Company recorded from January 1, 2011 to the closing date of the sale. Under the full cost method of accounting for oil and natural gas properties, the sale proceeds were accounted for as a reduction of capitalized costs in April 2011. The Company also eliminated the asset retirement obligation associated with its off-shore oil and gas properties. This obligation amounted to $37.5 million and was accounted for as a reduction of capitalized costs under the full cost method of accounting for oil and natural gas properties as well as a reduction of the asset retirement obligation.

Table of Contents

Item 1. Financial Statements (Cont.)

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. In accordance with the SEC final rule on Modernization of Oil and Gas Reporting, the natural gas and oil prices used to calculate the full cost ceiling (as of June 30, 2011) 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, 2011, the Company s capitalized costs were below the full cost ceiling for the Company s oil and gas properties. As a result, an impairment charge was not required at June 30, 2011.

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

	At June 30, 2011	At September 30, 2010
Funded Status of the Pension and Other Post-Retirement Benefit Plans	$ (79,465)	$ (79,465)
Cumulative Foreign Currency Translation Adjustment		(51)
Net Unrealized Gain on Derivative Financial Instruments	557	32,876
Net Unrealized Gain on Securities Available for Sale	3,810	1,655
Accumulated Other Comprehensive Loss	$ (75,098)	$ (44,985)

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

	At June 30, 2011	At September 30, 2010
Prepayments	$ 12,645	$ 13,884
Prepaid Property and Other Taxes	10,653	12,413
Federal Income Taxes Receivable	9,514	56,334
State Income Taxes Receivable	7,902	18,007
Fair Values of Firm Commitments	4,072	15,331
	$ 44,786	$ 115,969

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 6,512 antidilutive securities for the quarter ended June 30, 2011. There were no antidilutive securities for the nine months ended June 30, 2011. There were 544,500 and 237,538 antidilutive securities for the quarter and nine months ended June 30, 2010, respectively.

Table of Contents

Item 1. Financial Statements (Cont.)

Stock-Based Compensation. During the nine months ended June 30, 2011, the Company granted 180,000 non-performance based SARs having a weighted average exercise price of $63.87 per share. The weighted average grant date fair value of these SARs was $15.33 per share. These SARs may be settled in cash, in shares of common stock of the Company, or in a combination of cash and shares of common stock of the Company, as determined by the Company. These SARs 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. There were no SARs granted during the quarter ended June 30, 2011. The non-performance based SARs granted during the nine months ended June 30, 2011 vest and become exercisable annually in one-third increments. The weighted average grant date fair value of these non-performance based SARs granted during the nine months ended June 30, 2011 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 quarter or nine months ended June 30, 2011. The Company did not recognize a tax benefit related to the exercise of stock options for the calendar year ended December 31, 2010 due to tax loss carryforwards. The Company expects to recognize a tax benefit of $18.1 million in Paid in Capital related to calendar 2010 stock option exercises in future years as the tax loss carryforward is utilized.

The Company granted 47,250 restricted share awards (non-vested stock as defined by the current accounting literature) during the nine months ended June 30, 2011. The weighted average fair value of such restricted shares was $63.98 per share. There were no restricted share awards granted during the quarter ended June 30, 2011. In addition, the Company granted 8,100 and 37,000 restricted stock units during the quarter and nine months ended June 30, 2011, respectively. The weighted average fair value of such restricted stock units was $65.50 per share and $59.82 per share for the quarter and nine months ended June 30, 2011, respectively. 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.

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 will be effective as of the Company s second quarter of fiscal 2012. The Company is currently evaluating the impact that adoption of this authoritative guidance will have on its consolidated financial statement disclosures.

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 to the Company s financial statements.

Table of Contents

Item 1. Financial Statements (Cont.)

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 has the ability to 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, 2011 and September 30, 2010. 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, 2011			
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
Assets:				
Cash Equivalents Money Market Mutual Funds	$ 118,652	$	$	$ 118,652
Derivative Financial Instruments:				
Commodity Futures Contracts Gas	56			56
Over the Counter Swaps Oil		(176)		(176)
Over the Counter Swaps Gas		43,367		43,367
Other Investments:				
Balanced Equity Mutual Fund	22,030			22,030
Common Stock Financial Services Industry	6,979			6,979
Other Common Stock	237			237
Hedging Collateral Deposits	37,984			37,984
Total	$ 185,938	$ 43,191	$	$ 229,129
Liabilities:				
Derivative Financial Instruments:				
Commodity Futures Contracts Gas	$ 2,960	$	$	$ 2,960
Over the Counter Swaps Oil			50,453	50,453
Over the Counter Swaps Gas		(8,806)		(8,806)
Total	$ 2,960	$ (8,806)	$ 50,453	$ 44,607
Total Net Assets/(Liabilities)	$ 182,978	$ 51,997	$ (50,453)	$ 184,522

Table of Contents

Item 1. Financial Statements (Cont.)

Recurring Fair Value Measures (Thousands of Dollars)	At fair value as of September 30, 2010 Level 1	Level 2	Level 3	Total
Assets:				
Cash Equivalents Money Market Mutual Funds	$ 277,423	$	$	$ 277,423
Derivative Financial Instruments:				
Over the Counter Swaps Gas		67,387		67,387
Over the Counter Swaps Oil			(2,203)	(2,203)
Other Investments:				
Balanced Equity Mutual Fund	17,256			17,256
Common Stock Financial Services Industry	4,991			4,991
Other Common Stock	241			241
Hedging Collateral Deposits	11,134			11,134
Total	$ 311,045	$ 67,387	$ (2,203)	$ 376,229
Liabilities:				
Derivative Financial Instruments:				
Commodity Futures Contracts Gas	$ 5,840	$	$	$ 5,840
Over the Counter Swaps Oil			14,280	14,280
Over the Counter Swaps Gas		40		40
Total	$ 5,840	$ 40	$ 14,280	$ 20,160
Total Net Assets/(Liabilities)	$ 305,205	$ 67,347	$ (16,483)	$ 356,069

Derivative Financial Instruments

At June 30, 2011 and September 30, 2010, 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. Hedging collateral deposits of $5.6 million (at June 30, 2011) and $10.1 million (at September 30, 2010), 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, 2011 consist of crude oil and natural gas price swap agreements used in the Company s Exploration and Production and Energy Marketing segments. At September 30, 2010, the derivative financial instruments reported in Level 2 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 the majority of the Company s Exploration and Production segment s crude oil price swap agreements at June 30, 2011 and all of its crude oil price swap agreements at September 30, 2010. Hedging collateral deposits of $32.4 million and $1.0 million associated with these crude oil price swap agreements have been reported in Level 1 at June 30, 2011 and September 30, 2010, respectively. 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). Based on an assessment of the counterparties credit risk, the fair market value of the price swap agreements reported as Level 2 assets have been reduced by $0.4 million and $1.0 million at June 30, 2011 and September 30, 2010, respectively. 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 have been reduced by $0.1 million and $0.3 million at June 30, 2011 and September 30, 2010, respectively. 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.

Table of Contents

Item 1. Financial Statements (Cont.)

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, 2011 and 2010, respectively. For the quarters and nine months ended June 30, 2011 and June 30, 2010, 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)

	April 1, 2011	Total Gains/Losses: Gains/Losses Realized and Included in Earnings	Total Gains/Losses: Gains/Losses Unrealized and Included in Other Comprehensive Income (Loss)	Transfer In/Out of Level 3	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	Total Gains/Losses: 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.

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

	April 1, 2010	Total Gains/Losses: Gains/Losses Realized and Included in Earnings	Total Gains/Losses: Gains/Losses Unrealized and Included in Other Comprehensive Income (Loss)	Transfer In/Out of Level 3	June 30, 2010
Derivative Financial Instruments[2]	$ (14,100)	$ (2,172)[1]	$ 16,126	$	$ (146)

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the three months ended June 30, 2010.

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

Table of Contents

Item 1. Financial Statements (Cont.)

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

		Total Gains/Losses			
	October 1, 2010	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, 2010
Derivative Financial Instruments[2]	$ 26,969	$ (6,969)[1]	$ (20,146)	$	$ (146)

[1] Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the nine months ended June 30, 2010.
[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, 2011		September 30, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt	$ 1,049,000	$ 1,209,054	$ 1,249,000	$ 1,423,349

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

Other investments include cash surrender values of insurance contracts (net present value in the case of split-dollar collateral assignment arrangements) and marketable equity securities. The values of the insurance contracts amounted to $54.9 million at June 30, 2011 and $55.4 million at September 30, 2010. The fair value of the equity mutual fund was $22.0 million at June 30, 2011 and $17.3 million at September 30, 2010. The gross unrealized gain on this equity mutual fund was $1.5 million at June 30, 2011. The unrealized gain on the equity mutual fund at September 30, 2010 was negligible as the fair value was approximately equal to the cost basis. The fair value of the stock of an insurance company was $7.0 million at June 30, 2011 and $5.0 million at September 30, 2010. The gross unrealized gain on this stock was $4.6 million at June 30, 2011 and $2.6 million at September 30, 2010. 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 is exposed to certain risks relating to its ongoing business operations. The primary risk managed by using derivative instruments is 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, 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 majority of the Company s hedges do not typically exceed 3 years.

Table of Contents

Item 1. Financial Statements (Cont.)

The Company has presented its net derivative assets and liabilities on its Consolidated Balance Sheets at June 30, 2011 and September 30, 2010 as shown in the table below.

Fair Values of Derivative Instruments (Dollar Amounts in Thousands)

	Asset Derivatives		Liability Derivatives	
Derivatives Designated as Hedging Instruments	**Consolidated Balance Sheet Location**	**Fair Value**	**Consolidated Balance Sheet Location**	**Fair Value**
Commodity Contracts at June 30, 2011	Fair Value of Derivative Financial Instruments	$43,247	Fair Value of Derivative Financial Instruments	$44,607
Commodity Contracts at September 30, 2010	Fair Value of Derivative Financial Instruments	$65,184	Fair Value of Derivative Financial Instruments	$20,160

The following table discloses the fair value of derivative contracts on a gross-contract basis as opposed to the net-contract basis presentation on the Consolidated Balance Sheets at June 30, 2011 and September 30, 2010.

Fair Values of Derivative Instruments (Dollar Amounts in Thousands)

Derivatives Designated as Hedging Instruments	**Gross Asset Derivatives Fair Value**	**Gross Liability Derivatives Fair Value**
Commodity Contracts at June 30, 2011	$54,971	$56,331
Commodity Contracts at September 30, 2010	$77,837	$32,813

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.

At June 30, 2011, 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	73.7 Bcf (all short positions)
Crude Oil	3,165,000 Bbls (all short positions)

-19-

Table of Contents

Item 1. Financial Statements (Cont.)

In conjunction with the sale of the Company s off-shore oil and natural gas properties in the Gulf of Mexico, the Company discontinued hedge accounting for the remaining derivative financial instruments that had been designated as hedges of Gulf of Mexico production. At June 30, 2011, natural gas derivative contracts totaling 0.4 Bcf were still outstanding. They were excluded from the table above since there is no forecasted sale associated with the hedged volume. Changes to the fair value of these natural gas derivative contracts, which mature in September 2011, are being reflected in the Consolidated Statement of Income.

At June 30, 2011, 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	6.6 Bcf (5.3 Bcf short positions (forecasted storage withdrawals) and 1.3 Bcf long positions (forecasted storage injections))

At June 30, 2011, the Company s Pipeline and Storage segment had 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	1.5 Bcf (all short positions)

At June 30, 2011, the Company s Exploration and Production segment had $0.1 million (less than $0.1 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that $3.2 million ($1.8 million after tax) of gains will be reclassified into the Consolidated Statement of Income (Loss) within the next 12 months as the expected sales of the underlying commodities occur. It is expected that $3.1 million ($1.7 million after tax) of losses will be reclassified into the Consolidated Statement of Income (loss) after 12 months. See Note 1, under Accumulated Other Comprehensive Income (Loss), for the after-tax gain (loss) pertaining to derivative financial instruments (Net Unrealized Gain (Loss) on Derivative Financial Instruments in Note 1 includes the Exploration and Production, Energy Marketing and Pipeline and Storage segments).

At June 30, 2011, the Company s Energy Marketing segment had $0.7 million ($0.5 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that the full amount will be reclassified into the Consolidated Statement of Income (Loss) within the next 12 months as the sales and purchases 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 (Net Unrealized Gain (Loss) on Derivative Financial Instruments in Note 1 includes the Exploration and Production, Energy Marketing and Pipeline and Storage segments).

At June 30, 2011, the Company s Pipeline and Storage segment had less than $0.1 million of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that the full amount will be reclassified into the Consolidated Statement of Income (Loss) 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 (Net Unrealized Gain (Loss) on Derivative Financial Instruments in Note 1 includes the Exploration and Production, Energy Marketing and Pipeline and Storage segments).

Table of Contents

Item 1. Financial Statements (Cont.)

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Three Months Ended June 30, 2011 and 2010 (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,	
	2011	2010		2011	2010		2011	2010
Commodity Contracts Exploration & Production segment	$ 25,399	$ 16,445	Operating Revenue	$ (5,548)	$ 11,592	Operating Revenue	$ 570	$
Commodity Contracts Energy Marketing segment	$ 737	$ 519	Purchased Gas	$ 1,793	$ 238	Purchased Gas	$	$
Commodity Contracts Pipeline & Storage segment	$ 242	$ (436)	Operating Revenue	$	$	Operating Revenue	$	$
Total	$ 26,378	$ 16,528		$ (3,755)	$ 11,830		$ 570	$

Table of Contents

Item 1. Financial Statements (Cont.)

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Nine Months Ended June 30, 2011 and 2010 (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, 2011	2010	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, 2011	2010	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, 2011	2010
Commodity Contracts Exploration & Production segment	$ (42,969)	$ 32,910	Operating Revenue	$ 5,415	$ 29,170	Operating Revenue	$ 570	$
Commodity Contracts Energy Marketing segment	$ 1,340	$ 5,821	Purchased Gas	$ 7,095	$ (209)	Purchased Gas	$	$
Commodity Contracts Pipeline & Storage	$ 27	$ 577	Operating Revenue	$	$ 511	Operating Revenue	$	$

segment						
Total	$ (41,602)	$ 39,308	$ 12,510	$ 29,472	$ 570	$

-22-

Item 1. **Financial Statements (Cont.)**

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 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, 2011, the Company s Energy Marketing segment had fair value hedges covering approximately 10.5 Bcf (7.4 Bcf of fixed price sales commitments (all long positions) and 3.1 Bcf of fixed price purchase commitments (all short positions)). For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting gain or loss on the hedged item attributable to the hedged risk completely offset each other in current earnings, as shown below.

Consolidated Statement of Income	Gain/(Loss) on Derivative		Gain/(Loss) on Commitment	
Operating Revenues	$	9,531,151	$	(9,531,151)
Purchased Gas	$	(941,391)	$	941,391

Derivatives in Fair Value Hedging Relationships	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, 2011 (In Thousands)	
Commodity Contracts Energy Marketing segment [1]	Operating Revenues	$	9,531
Commodity Contracts Energy Marketing segment [2]	Purchased Gas	$	(638)
Commodity Contracts Energy Marketing segment [3]	Purchased Gas	$	(303)
		$	8,590

(1) Represents hedging of fixed price sales commitments of natural gas.
(2) Represents hedging of fixed price purchase commitments of natural gas.
(3) Represents hedging of natural gas held in storage.

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 eleven counterparties of which nine are in a net gain position. The Company had derivative financial instruments that were in loss positions with the other two counterparties. On average, the Company had $4.7 million of credit exposure per counterparty in a gain position at June 30, 2011.

The maximum credit exposure per counterparty in a gain position at June 30, 2011 was $8.0 million. The Company had not received any collateral from these counterparties at June 30, 2011 since 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.

Table of Contents

Item 1. Financial Statements (Cont.)

As of June 30, 2011, eight of the eleven 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 would be required. At June 30, 2011, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $24.6 million according to the Company s internal model (discussed in Note 2 Fair Value Measurements). At June 30, 2011, the fair market value of the derivative financial instrument liabilities with a credit-risk related contingency feature was $41.6 million according to the Company s internal model (discussed in Note 2 Fair Value Measurements). The liability with one counterparty was $40.3 million. For its over-the-counter crude oil swap agreements, which are in a liability position, the Company was required to post $32.4 million in hedging collateral deposits at June 30, 2011. This is discussed in Note 1 under Hedging Collateral Deposits.

For its exchange traded futures contracts, the majority of which are in a liability position, the Company had posted $5.6 million in hedging collateral as of June 30, 2011. As these are exchange traded futures contracts, there are no specific credit-risk related contingency features. The Company posts hedging collateral based on open positions and margin requirements it has with its counterparties.

The Company s requirement to post hedging collateral deposits is based on the fair value determined by the Company s counterparties, which may differ from the Company s assessment of fair value. Hedging collateral deposits may also include closed derivative positions in which the broker has not cleared the cash from the account to offset the derivative liability. The Company records liabilities related to closed derivative positions in Other Accruals and Current Liabilities on the Consolidated Balance Sheet. These liabilities are relieved when the broker clears the cash from the hedging collateral deposit account. This is discussed in Note 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,	
	2011	2010
Current Income Taxes		
Federal	$ (1,825)	$ 42,323
State	2,703	9,914
Deferred Income Taxes		
Federal	112,385	50,079
State	27,941	13,734
	141,204	116,050
Deferred Investment Tax Credit	(523)	(523)
Total Income Taxes	$ 140,681	$ 115,527
Presented as Follows:		
Other Income	$ (523)	$ (523)
Income Tax Expense Continuing Operations	141,204	115,449
Income from Discontinued Operations		601
Total Income Taxes	$ 140,681	$ 115,527

Table of Contents

Item 1. Financial Statements (Cont.)

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, 2011	Nine Months Ended June 30, 2010
U.S. Income Before Income Taxes	$ 361,726	$ 303,039
Income Tax Expense, Computed at Federal Statutory Rate of 35%	$ 126,604	$ 106,064
Increase (Reduction) in Taxes Resulting from:		
State Income Taxes	19,919	15,371
Miscellaneous	(5,842)	(5,908)
Total Income Taxes	$ 140,681	$ 115,527

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

	At June 30, 2011	At September 30, 2010
Deferred Tax Liabilities:		
Property, Plant and Equipment	$ 1,035,695	$ 849,869
Pension and Other Post-Retirement Benefit Costs	183,651	177,853
Other	38,958	63,671
Total Deferred Tax Liabilities	1,258,304	1,091,393
Deferred Tax Assets:		
Pension and Other Post-Retirement Benefit Costs	(227,458)	(223,588)
Tax Loss Carryforwards	(54,472)	(9,772)
Other	(80,114)	(81,751)
Total Deferred Tax Assets	(362,044)	(315,111)
Total Net Deferred Income Taxes	$ 896,260	$ 776,282
Presented as Follows:		
Net Deferred Tax Liability/(Asset) Current	$ (22,885)	$ (24,476)
Net Deferred Tax Liability Non-Current	919,145	800,758
Total Net Deferred Income Taxes	$ 896,260	$ 776,282

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 at June 30, 2011 that arose directly from excess tax deductions related to stock-based compensation. A tax benefit of $18.1 million relating to the excess stock-based compensation deductions will be recorded in Paid in Capital in future years when such tax benefit is 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 $70.3 million and $69.6 million at June 30, 2011 and September 30, 2010, 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 $151.1 million and $149.7 million at June 30, 2011 and September 30, 2010, respectively.

Table of Contents

Item 1. Financial Statements (Cont.)

The Company files U.S. federal and various state income tax returns. The Internal Revenue Service (IRS) is currently conducting an examination of the Company for fiscal 2010 and 2011 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 2008 and later years, IRS examinations for fiscal 2008 and prior years have been completed and the Company believes such years are effectively settled. During fiscal 2009, consent was received from the IRS National Office approving the Company s application to change its tax method of accounting for certain capitalized costs relating to its utility property. During fiscal 2010, local IRS examiners proposed to disallow most of the accounting method change recorded by the Company in fiscal 2009. The Company has filed a protest 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 operating subsidiaries mainly operate 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, 2011, the Company issued 1,044,970 original issue shares of common stock as a result of stock option and SARs exercises and 47,250 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 24,499 original issue shares of common stock for the Direct Stock Purchase and Dividend Reinvestment Plan. The Company also issued 11,250 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, 2011. 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, 2011, 503,262 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, 2011 consists of $150 million of 6.70% medium-term notes that mature in November 2011. Current Portion of Long-Term Debt at September 30, 2010 consisted of $200 million of 7.50% notes that matured in November 2010.

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. The Company has received approval from the NYDEC of a Remedial Design work plan for this site and has recorded an estimated minimum liability for remediation of this site of $14.5 million.

At June 30, 2011, 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 $17.2 million to $21.4 million. The minimum estimated liability of $17.2 million, which includes the $14.5 million discussed above, has been recorded on the Consolidated Balance Sheet at June 30, 2011. The Company expects to recover its environmental clean-up costs through rate recovery.

Table of Contents

Item 1. Financial Statements (Cont.)

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 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.

Note 7 Discontinued Operations

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

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

(Thousands)	Three Months Ended June 30, 2010	Nine Months Ended June 30, 2010
Operating Revenues	$ 2,135	$ 8,411
Operating Expenses	2,177	7,021
Operating Income (Loss)	(42)	1,390
Interest Income	1	1
Other Interest Expense	(8)	(19)
Income (Loss) before Income Taxes	(49)	1,372
Income Tax Expense	8	601
Income (Loss) from Discontinued Operations	$ (57)	$ 771

Note 8 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 2010 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 2010 Form 10-K. As for segment assets, the only significant changes from the segment assets disclosed in the 2010 Form 10-K involve the Exploration and Production segment as well as Corporate and Intersegment Eliminations. Total Exploration and Production segment assets have increased by $184.6 million while Corporate and Intersegment Eliminations have decreased by $163.3 million.

Table of Contents

Item 1. Financial Statements (Cont.)

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

Quarter Ended June 30, 2010 (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	$ 126,326	$ 32,086	$ 112,802	$ 72,830	$ 344,044	$ 7,724	$ 224	$ 351,992
Intersegment Revenues	$ 2,653	$ 19,466	$	$	$ 22,119	$ 1,418	$ (23,537)	$
Segment Profit:								
Income (Loss) from Continuing Operations	$ 5,969	$ 7,234	$ 27,883	$ 1,411	$ 42,497	$ 243	$ (98)	$ 42,642

Nine Months Ended June 30, 2010 (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	$ 707,323	$ 107,560	$ 328,312	$ 303,103	$ 1,446,298	$ 27,157	$ 652	$ 1,474,107
Intersegment Revenues	$ 13,315	$ 60,289	$	$	$ 73,604	$ 1,418	$ (75,022)	$
Segment Profit:								
Income (Loss) from Continuing Operations	$ 62,254	$ 30,036	$ 85,046	$ 8,472	$ 185,808	$ 2,154	$ (1,221)	$ 186,741

Table of Contents

Item 1. Financial Statements (Cont.)

Note 9 Investments in Unconsolidated Subsidiaries

At June 30, 2011, the Company owns a 50% interest in ESNE. ESNE is an 80-megawatt, combined cycle, natural gas-fired turbine power plant in North East, Pennsylvania that is in the process of being dismantled. The Company expects to recover its investment in ESNE through the sale of ESNE s major assets, such as the power turbines.

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.

A summary of the Company s investments in unconsolidated subsidiaries at June 30, 2011 and September 30, 2010 is as follows (in thousands):

	At June 30, 2011	At September 30, 2010
Seneca Energy	$	$ 11,007
Model City		2,017
ESNE	1,367	1,804
	$ 1,367	$ 14,828

Note 10 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	
	2011	2010	2011	2010
Service Cost	$ 3,693	$ 3,249	$ 1,069	$ 1,075
Interest Cost	10,669	11,077	5,471	6,254
Expected Return on Plan Assets	(14,776)	(14,585)	(7,291)	(6,583)
Amortization of Prior Service Cost	147	164	(427)	(427)
Amortization of Transition Amount			135	135
Amortization of Losses	8,718	5,410	5,948	6,470
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) [(1)]	(2,346)	(920)	1,602	(569)
Net Periodic Benefit Cost	$ 6,105	$ 4,395	$ 6,507	$ 6,355

Table of Contents

Item 1. Financial Statements (Cont.)

Nine months ended June 30,

	Retirement Plan		Other Post-Retirement Benefits	
	2011	2010	2011	2010
Service Cost	$ 11,079	$ 9,747	$ 3,207	$ 3,224
Interest Cost	32,007	33,231	16,413	18,763
Expected Return on Plan Assets	(44,328)	(43,756)	(21,873)	(19,751)
Amortization of Prior Service Cost	441	492	(1,282)	(1,282)
Amortization of Transition Amount			405	405
Amortization of Losses	26,155	16,230	17,845	19,411
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) [1]	(584)	2,896	9,564	2,919
Net Periodic Benefit Cost	$ 24,770	$ 18,840	$ 24,279	$ 23,689

(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, 2011, the Company contributed $40.0 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 2011 the Company expects to contribute between $8.0 and $9.0 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 2011 in order to be in compliance with the Pension Protection Act of 2006. In the remainder of 2011 the Company expects to contribute between $1.0 and $6.5 million to its VEBA trusts and 401(h) accounts.

Table of Contents

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, 2011 compared to the quarter ended June 30, 2010, the Company experienced an increase in earnings of $4.3 million. The earnings increase for the quarter is primarily due to higher earnings in the Exploration and Production segment and the All Other category partially offset by lower earnings in the Pipeline & Storage segment and the Corporate category. For the nine months ended June 30, 2011 compared to the nine months ended June 30, 2010, the Company experienced an increase in earnings of $33.5 million. The earnings increase for the nine-month period is primarily due to the recognition of a gain on the sale of unconsolidated subsidiaries of $50.9 million ($31.4 million after tax) during the quarter ended March 31, 2011 in the All Other category. In February 2011, the Company sold its 50% equity method investments in Seneca Energy and Model City for $59.4 million. Seneca Energy and Model City generate and sell electricity using methane gas obtained from landfills owned by outside parties. The sale is the result of the Company s strategy to pursue the sale of smaller, non-core assets in order to focus on its core businesses, including the development of the Marcellus Shale and the expansion of its pipeline business throughout the Appalachian region.

The Marcellus Shale is 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. Due to the depth at which this formation is found, drilling and completion costs, including the drilling and completion of horizontal wells with hydraulic fracturing, are very expensive. However, independent geological studies have indicated that this formation could yield natural gas reserves measured in the trillions of cubic feet. The Company controls approximately 745,000 net acres within the Marcellus Shale area of Pennsylvania, with a majority of the acreage held in fee, carrying no royalty and no lease expirations. The Company s reserve base has grown substantially from development in the Marcellus Shale. Natural gas proved developed and undeveloped reserves in the Appalachian region increased from 150 Bcf at September 30, 2009 to 331 Bcf at September 30, 2010. With this in mind, and with a natural desire to realize the value of these assets in a responsible and orderly fashion, the Company has spent significant amounts of capital in this region. For the nine months ended June 30, 2011, the Company spent $433.5 million towards the development of the Marcellus Shale. This includes paying $24.1 million in November 2010 for the acquisition of additional oil and gas properties in the Covington Township area of Tioga County, Pennsylvania from EOG Resources, Inc. These properties are producing natural gas from the Marcellus Shale and are also prospective for additional Marcellus reserves. As a result of the transaction, it is anticipated that the Appalachian region of the Exploration and Production segment will add approximately 42 Bcf of proved natural gas reserves, thereby having an immediate positive impact on the Company s production and proved reserves.

As the Company has been accelerating its Marcellus Shale development, it has been decreasing its emphasis in the Gulf Coast region. In March 2011, the Company entered into a purchase and sale agreement to sell its off-shore oil and natural gas properties effective as of January 1, 2011 in the Gulf of Mexico for approximately $70 million and received a deposit of $7.0 million from the purchaser. The Company completed the sale in April 2011, receiving an additional $54.8 million. The difference between the total proceeds received of $61.8 million and the sale price of $70.0 million represents a purchase price adjustment for the operating cash flow that the Company recorded from January 1, 2011 to the closing date of the sale. Under the full cost method of accounting for oil and natural gas properties, the sale proceeds were accounted for as a reduction of capitalized costs in April 2011. The Company also eliminated the asset retirement obligation associated with its off-shore oil and gas properties. This obligation amounted to $37.5 million and was accounted for as a reduction of capitalized costs under the full cost method of accounting for oil and natural gas properties as well as a reduction of the asset retirement obligation. 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.

Table of Contents

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

In September, 2010, the Company engaged Jefferies & Company (Jefferies) to explore joint-venture opportunities across its Marcellus Shale acreage in its Exploration and Production segment. At that time, the Company believed that a joint-venture could allow the Company to enhance shareholder value by shifting a significant portion of the early drilling costs for shale wells to a noncontrolling-interest partner while still allowing the Company to continue operating across most of its acreage. The Company and Jefferies established a data room to highlight the value of the Company s position in the Marcellus Shale, and invited qualified parties to review the information in contemplation of entering into a joint venture. The Company has had discussions with many of the parties that have visited the data room and has received some offers. However, the Company has decided not to pursue these offers. Throughout this process, the Company has continued its drilling operations in the Marcellus Shale and has achieved favorable results. Since a majority of the Company s acreage is held in fee, carrying no royalty and no lease expirations, and large, contiguous acreage blocks allow for operating- and cost-efficiency through multi-well pad drilling, the Company is not forced to take extraordinary steps to maintain its mineral acreage. The Company will forgo any joint-venture opportunities that do not enhance shareholder value when compared to the growth that it could expect to achieve without a joint venture partner. While discussions with certain potential partners continue, at this time it is likely that the Company will develop its Marcellus Shale acreage on its own.

Coincident with the development of its Marcellus Shale acreage, the Company s Pipeline and Storage segment is building 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. Two of the projects, the Tioga County Extension Project and the Northern Access expansion project, are considered significant for Empire and Supply Corporation. Both projects are 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. During the past year, Empire and Supply Corporation have experienced a decline in the volumes of natural gas received at the Canada/United States border at the Niagara River to be shipped across their systems. The historical price advantage for gas sold at the Niagara import points has declined as production in the Canadian producing regions has declined or been diverted to other demand areas, and as production from new shale plays has increased in the United States. This factor has been causing shippers to seek alternative gas supplies and consequently alternative transportation routes. The Tioga County Extension Project and the Northern Access expansion project are designed to provide an alternative gas supply source for the customers of Empire and Supply Corporation. These projects, which are discussed more completely in the Investing Cash Flow section that follows, will involve significant capital expenditures.

From a capital resources perspective, the Company has been able to meet its capital expenditure needs for all of the above projects by using cash from operations and short-term borrowings. The Company had $184.7 million in Cash and Temporary Cash Investments at June 30, 2011, as shown on the Company s Consolidated Balance Sheet. For the remainder of fiscal 2011, the Company expects that it will be able to use cash on hand, cash from operations, and cash from asset sales as its first means of financing capital expenditures, with short-term borrowings and long-term borrowings being its next sources of funding. It is not expected that long-term financing will be required to meet capital expenditure needs until the later part of fiscal 2011 or in fiscal 2012.

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 DEC has issued its recommendations for shale development and production. However, the recommendations have not gone into effect since they are subject to a 60-day public comment period that is anticipated to begin sometime in August 2011. Due to the small amount of Marcellus Shale acreage owned by the Company in New York State, the final outcome of the

Table of Contents

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

DEC 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, 2010 as well as updates to that section in the Form 10-Q for the quarter ended December 31, 2010 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 2010 Form 10-K and Item 2 of the Company s December 31, 2010 and March 31, 2011 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, 2011, the ceiling exceeded the book value of the oil and gas properties by approximately $289 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, 2011, based on posted Midway-Sunset prices was $87.63 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, 2011, based on the quoted Henry Hub spot price for natural gas, was $4.21 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, 2011.) If natural gas average prices used in the ceiling test calculation at June 30, 2011 had been $1 per MMBtu lower, the ceiling would have exceeded the book value of the Company s oil and gas properties by approximately $157 million. If crude oil average prices used in the ceiling test calculation at June 30, 2011 had been $5 per Bbl lower, the ceiling would have exceeded the book value of the Company s oil and gas properties by approximately $247 million. If both natural gas and crude oil average prices used in the ceiling test calculation at June 30, 2011 were lower by $1 per MMBtu and $5 per Bbl, respectively, the ceiling would have exceeded the book value of the Company s oil and gas properties by approximately $116 million. 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 2010 Form 10-K.

Accounting for Derivative Financial Instruments. The Company, in its Exploration and Production segment, Energy Marketing segment, and Pipeline and Storage segment, uses a variety of derivative financial instruments to manage a portion of the market risk associated with fluctuations in the price of natural gas and crude oil. These instruments are categorized as price swap agreements and futures contracts. In accordance with the authoritative guidance for derivative instruments and hedging activities, the Company accounted for these instruments as effective cash flow hedges or fair value hedges. Gains or losses associated with the derivative financial instruments are matched with gains or losses resulting from the underlying physical transaction that is being hedged. To the extent that the derivative financial instruments would ever be deemed to be ineffective based on the effectiveness testing, mark-to-market gains or losses from the derivative financial instruments would be recognized in the income statement without regard to an underlying physical transaction. In April 2011, the Company completed the sale of its off-shore oil and natural gas properties in the Gulf of Mexico and discontinued hedge accounting for the remaining derivative financial instruments that had been designated as hedges of the Gulf of Mexico production. Accordingly, $0.6 million of unrealized gains associated with such derivative financial instruments was reclassified from accumulated other comprehensive income to the income statement in April 2011.

Table of Contents

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

The Company uses both exchange-traded and non exchange-traded derivative financial instruments. The Company adopted the authoritative guidance for fair value measurements during the quarter ended December 31, 2008. As such, the fair value of such derivative financial instruments is determined under the provisions of this guidance. The fair value of exchange traded derivative financial instruments is determined from Level 1 inputs, which are quoted prices in active markets. The Company determines the fair value of non exchange-traded derivative financial instruments based on an internal model, which uses both observable and unobservable inputs other than quoted prices. These inputs are considered Level 2 or Level 3 inputs. All derivative financial instrument assets and liabilities are evaluated for the probability of default by either the counterparty or the Company. Credit reserves are applied against the fair values of such assets or liabilities. Refer to the Market Risk Sensitive Instruments section below for further discussion of the Company s derivative financial instruments.

RESULTS OF OPERATIONS

Earnings

The Company s earnings were $46.9 million for the quarter ended June 30, 2011 compared to earnings of $42.6 million for the quarter ended June 30, 2010. The increase in earnings of $4.3 million is primarily a result of higher earnings in the Exploration and Production segment and the All Other category. Lower earnings in the Pipeline and Storage segment and the Corporate category slightly offset these increases. As previously discussed, the Company sold its landfill gas operations in the states of Ohio, Michigan, Kentucky, Missouri, Maryland and Indiana in September 2010. Accordingly, all financial results for these operations, which are part of the All Other category, have been presented as discontinued operations. Discontinued operations did not have a material impact on quarterly earnings, as shown in the table below.

The Company s earnings were $221.0 million for the nine months ended June 30, 2011 compared to earnings of $187.5 million for the nine months ended June 30, 2010. The Company s earnings from continuing operations were $221.0 million for the nine months ended June 30, 2011 compared with $186.7 million for the nine months ended June 30, 2010. The increase in earnings from continuing operations of $34.3 million is primarily the result of higher earnings in the All Other category and the Exploration and Production segment. Lower earnings in the Pipeline and Storage segment and the Corporate category slightly offset these increases. 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)	2011	2010	Increase (Decrease)	2011	2010	Increase (Decrease)
Utility	$ 6,328	$ 5,969	$ 359	$ 62,399	$ 62,254	$ 145
Pipeline and Storage	4,503	7,234	(2,731)	24,036	30,036	(6,000)
Exploration and Production	32,784	27,883	4,901	93,455	85,046	8,409
Energy Marketing	1,891	1,411	480	9,122	8,472	650
Total Reportable Segments	45,506	42,497	3,009	189,012	185,808	3,204
All Other	2,713	243	2,470	34,320	2,154	32,166
Corporate	(1,328)	(98)	(1,230)	(2,287)	(1,221)	(1,066)
Total Earnings from Continuing Operations	46,891	42,642	4,249	221,045	186,741	34,304
Earnings (Loss) from Discontinued Operations		(57)	57		771	(771)

Total Consolidated	$ 46,891	$ 42,585	$ 4,306	$ 221,045	$ 187,512	$ 33,533

Table of Contents

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

Utility

Utility Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2011	2010	Increase (Decrease)	2011	2010	Increase (Decrease)
Retail Sales Revenues:						
Residential	$ 105,001	$ 88,158	$ 16,843	$ 545,786	$ 521,202	$ 24,584
Commercial	12,474	10,721	1,753	73,833	73,438	395
Industrial	807	696	111	4,951	4,579	372
	118,282	99,575	18,707	624,570	599,219	25,351
Transportation	25,016	20,909	4,107	105,380	92,112	13,268
Off-System Sales	3,976	5,486	(1,510)	29,564	20,491	9,073
Other	2,416	3,009	(593)	5,968	8,816	(2,848)
	$ 149,690	$ 128,979	$ 20,711	$ 765,482	$ 720,638	$ 44,844

Utility Throughput

	Three Months Ended June 30,			Nine Months Ended June 30,		
(MMcf)	2011	2010	Increase (Decrease)	2011	2010	Increase
Retail Sales:						
Residential	8,867	7,055	1,812	54,075	50,292	3,783
Commercial	1,203	920	283	8,044	7,666	378
Industrial	79	66	13	618	512	106
	10,149	8,041	2,108	62,737	58,470	4,267
Transportation	12,335	10,530	1,805	57,916	51,957	5,959
Off-System Sales	867	1,124	(257)	6,188	4,034	2,154
	23,351	19,695	3,656	126,841	114,461	12,380

Degree Days

				Percent Colder (Warmer) Than	
	Normal	2011	2010	Normal [1]	Prior Year [1]
Three Months Ended June 30					
Buffalo	927	848	665	(8.5)	27.5

Erie	885	812	631	(8.2)	28.7
Nine Months Ended June 30					
Buffalo	6,514	6,674	6,152	2.5	8.5
Erie	6,108	6,284	5,842	2.9	7.6

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

2011 Compared with 2010

Operating revenues for the Utility segment increased $20.7 million for the quarter ended June 30, 2011 as compared with the quarter ended June 30, 2010. This increase largely resulted from an $18.7 million increase in retail gas sales revenues and a $4.1 million increase in transportation revenues. These increases were partially offset by a $1.5 million decrease in off-system sales revenues and a $0.6 million decrease in other operating revenues. The increase in retail gas sales revenues of $18.7 million was largely a function of higher volumes (2.1 Bcf) due to colder weather and higher customer usage per account. The phrase usage per account refers to the average gas consumption per customer account after factoring out any impact that weather may have had on consumption. The increase in volumes resulted in the recovery of a larger amount of gas costs, despite a decline in the Utility segment s average cost of purchased gas. The

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

Utility segment s average cost of purchased gas, including the cost of transportation and storage, was $6.43 per Mcf for the three months ended June 30, 2011, a decrease of 4.0% from the average cost of $6.70 per Mcf for the three months ended June 30, 2010. Subject to certain timing variations, gas costs are recovered dollar for dollar in revenues. The increase in transportation revenues of $4.1 million was primarily due to a 1.8 Bcf increase in transportation throughput, largely the result of colder weather and the migration of customers from retail sales to transportation service. The decrease in off-system sales revenues was largely due to a decrease in off-system sales volume. Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal and there was not a material impact to margins. The $0.6 million decrease in other operating revenues was largely attributable to a lower undercollection of pension and other post-retirement benefit costs quarter over quarter.

Operating revenues for the Utility segment increased $44.8 million for the nine months ended June 30, 2011 as compared with the nine months ended June 30, 2010. This increase largely resulted from a $25.4 million increase in retail gas sales revenues, a $13.3 million increase in transportation revenues and a $9.1 million increase in off-system sales revenues. These increases were partially offset by a $2.8 million decrease in other operating revenues. The increase in retail gas sales revenues of $25.4 million was largely a function of higher volumes (4.3 Bcf) due to colder weather and higher customer usage per account. The increase in volumes resulted in the recovery of a larger amount of gas costs, despite a decline in the Utility segment s average cost of purchased gas. The Utility segment s average cost of purchased gas, including the cost of transportation and storage, was $6.26 per Mcf for the nine months ended June 30, 2011, a decrease of 12.6% from the average cost of $7.16 per Mcf for the nine months ended June 30, 2010. Subject to certain timing variations, gas costs are recovered dollar for dollar in revenues. The increase in transportation revenues of $9.1 million was primarily due to a 6.0 Bcf increase in transportation throughput, largely the result of colder weather and the migration of customers from retail sales to transportation service. The increase in off-system sales revenues was largely due to an increase in off-system sales volume. Due to profit sharing with retail customers, the margins resulting from off-system sales are minimal and there was not a material impact to margins. The $2.8 million decrease in other operating revenues was largely attributable to a regulatory adjustment to reduce a previous undercollection of pension and other post-retirement benefit costs.

The Utility segment s earnings for the quarter ended June 30, 2011 were $6.3 million, an increase of $0.3 million when compared with earnings of $6.0 million for the quarter ended June 30, 2010.

In the New York jurisdiction, earnings decreased $1.5 million. The decrease in earnings was largely due to various regulatory true-up adjustments ($0.6 million), an increase in other taxes ($0.4 million) and higher income tax expense ($0.4 million). The regulatory true-up adjustments related primarily to a lower undercollection of pension and other post-retirement benefit costs quarter over quarter.

In the Pennsylvania jurisdiction, earnings increased $1.8 million. The earnings increase was largely attributable to higher usage per account ($0.6 million) and colder weather ($1.4 million). These increases were partially offset by the negative earnings impact associated with a higher effective tax rate ($0.5 million).

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, 2011, the WNC reduced earnings by $0.2 million, as it was colder than normal. For the quarter ended June 30, 2010, the WNC preserved earnings of approximately $1.0 million, as weather was warmer than normal for the period.

The Utility segment s earnings for the nine months ended June 30, 2011 were $62.4 million, an increase of $0.1 million when compared with earnings of $62.3 million for the nine months ended June 30, 2010.

Table of Contents

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

In the New York jurisdiction, earnings decreased $4.0 million. The decrease in earnings was mainly due to various regulatory true-up adjustments ($2.1 million), which was largely attributable to a regulatory adjustment to reduce a previous undercollection of pension and other post-retirement benefit costs. In addition, the negative earnings impact associated with an increase in other taxes ($0.9 million), higher depreciation expense ($0.5 million), higher interest expense on deferred gas costs ($0.4 million) and higher income tax expense ($0.7 million) further reduced earnings.

In the Pennsylvania jurisdiction, earnings increased $4.1 million. The earnings increase was largely attributable to higher usage per account ($2.1 million) and colder weather ($2.4 million). In addition, the positive earnings impact associated with lower interest expense on deferred gas costs ($0.9 million) further increased earnings. These increases were partially offset by the negative earnings impact associated with higher income tax expense of $0.9 million.

For the nine months ended June 30, 2011, the WNC in the New York jurisdiction reduced earnings by $1.0 million, as it was colder than normal. For the nine months ended June 30, 2010, the WNC in the New York jurisdiction preserved earnings of approximately $1.3 million, as weather was warmer than normal.

Pipeline and Storage

Pipeline and Storage Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2011	2010	Increase (Decrease)	2011	2010	Increase (Decrease)
Firm Transportation	$ 31,208	$ 32,205	$ (997)	$ 103,448	$ 106,926	$ (3,478)
Interruptible Transportation	305	618	(313)	1,035	1,458	(423)
	31,513	32,823	(1,310)	104,483	108,384	(3,901)
Firm Storage Service	16,629	16,646	(17)	50,090	50,032	58
Interruptible Storage Service		19	(19)	19	78	(59)
Other	2,115	2,064	51	9,361	9,355	6
	$ 50,257	$ 51,552	$ (1,295)	$ 163,953	$ 167,849	$ (3,896)

Pipeline and Storage Throughput

	Three Months Ended June 30,			Nine Months Ended June 30,		
(MMcf)	2011	2010	Increase (Decrease)	2011	2010	Increase (Decrease)
Firm Transportation	53,326	52,448	878	266,545	245,233	21,312
Interruptible Transportation	489	1,016	(527)	1,709	3,575	(1,866)
	53,815	53,464	351	268,254	248,808	19,446

2011 Compared with 2010

Operating revenues for the Pipeline and Storage segment decreased $1.3 million in the quarter ended June 30, 2011 as compared with the quarter ended June 30, 2010. The decrease was primarily due to a decrease in transportation revenues of $1.3 million. The decrease in transportation revenues was primarily the result of a reduction in the level of contracts entered into by shippers quarter over quarter as shippers utilized lower priced pipeline transportation routes and a decrease in the gathering rate under Supply Corporation s tariff. Shippers continue to seek alternative lower priced gas supply (and in some cases, not renewing short-term transportation contracts) because of the relatively higher price of natural gas supplies available at the United States/Canadian border at the Niagara River near Buffalo, New York compared to the lower pricing for supplies available at Leidy, Pennsylvania. Empire s proposed Tioga County Extension Project and Supply Corporation s Northern Access expansion project, both of which are discussed in the Investing Cash Flow section that follows, are designed to utilize that available pipeline capacity by receiving natural gas produced from the Marcellus Shale and transporting it to Canada and the Northeast United States where demand has been growing.

Table of Contents

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

Operating revenues for the Pipeline and Storage segment for the nine months ended June 30, 2011 decreased $3.9 million as compared with the nine months ended June 30, 2010. The decrease was primarily due to a decrease in transportation revenues of $3.9 million, which was primarily the result of a reduction in the level of contracts entered into by shippers period over period as shippers utilized lower priced pipeline transportation routes, as discussed above.

Volume fluctuations generally do not have a significant impact on revenues as a result of the straight fixed-variable rate design utilized by Supply Corporation and Empire, but this rate design does not protect Supply Corporation or Empire in situations where shippers do not contract for that capacity at the same quantity and rate. In that situation, Supply Corporation or Empire can propose revised rates and services in a rate case at the FERC. Transportation volume for the quarter ended June 30, 2011 increased by 0.4 Bcf from the prior year s quarter. For the nine months ended June 30, 2011, transportation volumes increased by 19.4 Bcf from the prior year s nine-month period. While transportation volume increased largely due to colder weather, there was little impact on revenues due to the straight fixed-variable rate design.

The Pipeline and Storage segment s earnings for the quarter ended June 30, 2011 were $4.5 million, a decrease of $2.7 million when compared with earnings of $7.2 million for the quarter ended June 30, 2010. The earnings decrease was primarily due to the earnings impact of higher operating expenses ($2.1 million). The increase in operating expenses can be attributed primarily to reserve activity associated with preliminary project costs ($0.8 million), higher pension costs ($0.4 million), higher compressor maintenance costs ($0.4 million) and the write-off of expired and unused storage rights ($0.6 million). Lower transportation revenues of $0.9 million also contributed to the earnings decrease, as discussed above. Higher depreciation expense ($0.4 million) contributed to the decrease in earnings as well. The increase in depreciation expense is primarily the result of a revision during the quarter ended June 30, 2011 to correct accumulated depreciation as well as additional projects that were placed in service in the last year. These earnings decreases were slightly offset by an increase in the allowance for funds used during construction (equity component) of $0.5 million primarily due to construction commencing during the previous quarter on Supply Corporation s Line N Expansion Project and Lamont Phase II Project, as discussed in the Investing Cash Flow section that follows. Earnings also benefited from lower income tax expense of $0.3 million due to a lower effective tax rate.

The Pipeline and Storage segment s earnings for the nine months ended June 30, 2011 were $24.0 million, a decrease of $6.0 million when compared with earnings of $30.0 million for the nine months ended June 30, 2010. The decrease in earnings is primarily due to the earnings impact of higher operating expenses ($3.9 million), lower transportation revenues of $2.5 million, as discussed above, higher depreciation expense ($0.8 million) and higher property taxes ($0.4 million). The increase in operating expenses can be attributed primarily to higher pension expense ($1.1 million), reserve activity associated with preliminary project costs ($0.6 million), higher compressor maintenance costs ($0.6 million) and the write-off of expired and unused storage rights ($0.6 million). The increase in property taxes is primarily a result of additional property and higher Pennsylvania public utility realty taxes. The increase in depreciation expense is primarily the result of a revision during the quarter ended June 30, 2011 to correct accumulated depreciation as well as additional projects that were placed in service in the last year. These earnings decreases were partially offset by an increase in the allowance for funds used during construction (equity component) of $1.0 million primarily due to construction commencing during the current year on Supply Corporation s Line N Expansion Project and Lamont Phase II Project, as discussed above, and lower income tax expense ($0.7 million) due to a lower effective tax rate.

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

Exploration and Production

Exploration and Production Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2011	2010	Increase (Decrease)	2011	2010	Increase (Decrease)
Gas (after Hedging)	$ 70,849	$ 48,381	$ 22,468	$ 202,114	$ 135,761	$ 66,353
Oil (after Hedging)	56,058	60,891	(4,833)	176,088	183,800	(7,712)
Gas Processing Plant	7,379	7,207	172	20,721	22,078	(1,357)
Other	337	218	119	265	380	(115)
Intrasegment Elimination (1)	(3,649)	(3,895)	246	(10,617)	(13,707)	3,090
	$ 130,974	$ 112,802	$ 18,172	$ 388,571	$ 328,312	$ 60,259

(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.

Production Volumes

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2011	2010	Increase (Decrease)	2011	2010	Increase (Decrease)
Gas Production *(MMcf)*						
Gulf Coast	22	2,745	(2,723)	4,092	8,079	(3,987)
West Coast	826	940	(114)	2,616	2,866	(250)
Appalachia	12,090	4,741	7,349	31,020	11,084	19,936
Total Production	12,938	8,426	4,512	37,728	22,029	15,699
Oil Production *(Mbbl)*						
Gulf Coast(1)	(9)	135	(144)	187	389	(202)
West Coast	661	661		1,958	2,007	(49)
Appalachia	13	13		35	34	1
Total Production	665	809	(144)	2,180	2,430	(250)

(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,			Nine Months Ended June 30,		
	2011	2010	Increase (Decrease)	2011	2010	Increase (Decrease)
Average Gas Price/Mcf						
Gulf Coast	N/M	$ 4.95	N/M	$ 5.02	$ 5.26	$ (0.24)
West Coast	$ 4.87	$ 4.38	$ 0.49	$ 4.40	$ 4.92	$ (0.52)
Appalachia	$ 4.55	$ 4.45	$ 0.10	$ 4.36	$ 5.10	$ (0.74)
Weighted Average	$ 4.67	$ 4.61	$ 0.06	$ 4.44	$ 5.13	$ (0.69)
Weighted Average After Hedging	$ 5.48	$ 5.74	$ (0.26)	$ 5.36	$ 6.16	$ (0.80)
Average Oil Price/Bbl						
Gulf Coast	N/M	$ 76.42	N/M	$ 88.57	$ 78.64	$ 9.93
West Coast	$ 108.30	$ 71.92	$ 36.38	$ 94.74	$ 71.79	$ 22.95
Appalachia	$ 92.89	$ 74.90	$ 17.99	$ 87.36	$ 77.77	$ 9.59
Weighted Average	$ 107.97	$ 72.72	$ 35.25	$ 94.10	$ 72.97	$ 21.13
Weighted Average After Hedging	$ 84.37	$ 75.23	$ 9.14	$ 80.78	$ 75.65	$ 5.13

N/M Not Meaningful

Table of Contents

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

2011 Compared with 2010

Operating revenues for the Exploration and Production segment increased $18.2 million for the quarter ended June 30, 2011 as compared with the quarter ended June 30, 2010. Gas production revenue after hedging increased $22.5 million. Increases in Appalachian natural gas production were partially offset by decreases in Gulf Coast production (as a result of the sale of the Exploration and Production segment s off-shore oil and natural gas properties in April 2011) and a $0.26 per Mcf decrease in the weighted average price of gas after hedging. The increase in Appalachian production was primarily due to additional wells within the Marcellus Shale formation, primarily in Tioga County, Pennsylvania, coming on line late in fiscal 2010 and the first nine months of fiscal 2011. Oil production revenue after hedging decreased $4.8 million as a result of the decrease in production due to the aforementioned sale of Gulf Coast off-shore properties, which more than offset the impact associated with the increase in the weighted average price of oil after hedging ($9.14 per Bbl).

Operating revenues for the Exploration and Production segment increased $60.3 million for the nine months ended June 30, 2011 as compared with the nine months ended June 30, 2010. Gas production revenue after hedging increased $66.4 million. Increases in Appalachian natural gas production were partially offset by decreases in Gulf Coast production (as a result of the sale of the Exploration and Production segment s off-shore oil and natural gas properties in April 2011) and an $0.80 per Mcf decrease in the weighted average price of gas after hedging. The increase in Appalachian production was primarily due to additional wells within the Marcellus Shale formation, primarily in Tioga County, Pennsylvania, coming on line late in fiscal 2010 and the first nine months of fiscal 2011. Oil production revenue after hedging decreased $7.7 million due largely to the decrease in production due to the aforementioned sale of off-shore properties, which more than offset the impact associated with the increase in the weighted average price of oil after hedging ($5.13 per Bbl). In addition, there was a $1.7 million increase in processing plant revenues (net of eliminations) primarily because of higher prices for gas processing plant liquids combined with a lower cost of West Coast gas production for the nine months ended June 30, 2011 as compared to the nine months ended June 30, 2010.

The Exploration and Production segment s earnings for the quarter ended June 30, 2011 were $32.8 million, an increase of $4.9 million when compared with earnings of $27.9 million for the quarter ended June 30, 2010. Higher crude oil prices and higher natural gas production increased earnings by $4.0 million and $16.8 million, respectively. In addition, higher processing plant revenues ($0.3 million), lower property and other taxes ($0.5 million), and lower interest expense ($2.2 million) also contributed to an increase in earnings. The decrease in interest expense is primarily due to a lower average amount of debt outstanding. The decrease in property and other taxes is largely due to the April 2011 sale of the Gulf Coast s off-shore properties and its impact on production and property taxes for the quarter. These earnings increases were partially offset by lower natural gas prices after hedging and lower crude oil production, which decreased earnings by $2.2 million and $7.1 million, respectively. In addition, earnings were further reduced by higher depletion expense ($5.2 million), higher lease operating expenses ($0.9 million), higher general, administrative and other operating expenses ($1.2 million), and higher income tax expense ($2.2 million). The increase in depletion expense is primarily due to an increase in production and depletable base (largely due to increased capital spending in the Appalachian region, specifically related to the development of Marcellus Shale properties). The increase in lease operating expenses is largely attributable to a higher number of producing properties in Appalachia. Higher personnel costs are largely responsible for the increase in general, administrative and other operating expenses. The increase in income tax expense is attributable to higher state income taxes coupled with the loss of a domestic production activities deduction that occurred during the quarter ended September 30, 2010 and its impact on the effective tax rate during fiscal 2011.

The Exploration and Production segment s earnings for the nine months ended June 30, 2011 were $93.5 million, an increase of $8.5 million when compared with earnings of $85.0 million for the nine months ended June 30, 2010. Higher crude oil prices and higher natural gas production increased earnings by $7.3 million and $62.9 million, respectively. In addition, higher processing plant revenues ($1.1 million) and lower interest expense ($5.8 million) also contributed to an increase in earnings. The decrease in interest expense is primarily due to a lower average amount of debt outstanding during the nine months ended June 30, 2011. These earnings increases were partially offset by lower natural gas prices after hedging and lower crude oil production, which decreased earnings by $19.8 million and $12.3 million, respectively. In addition, earnings

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

were further reduced by higher depletion expense ($20.7 million), higher lease operating expenses ($6.4 million), higher general, administrative and other operating expenses ($5.3 million), higher property and other taxes ($1.1 million), and higher income tax expense ($2.9 million). The increase in depletion expense is primarily due to an increase in production and depletable base (largely due to increased capital spending in the Appalachian region, specifically related to the development of Marcellus Shale properties). The increase in lease operating expenses is largely attributable to a higher number of producing properties in Appalachia. Higher personnel costs are largely responsible for the increase in general, administrative and other operating expenses. Higher property and other taxes are attributable to a revision of the California property tax liability, which was partially offset by the decrease in property and other taxes as a result of the sale of the Gulf Coast s off-shore properties in April 2011. The increase in income tax expense is attributable to higher state income taxes coupled with the loss of a domestic production activities deduction that occurred during the quarter ended September 30, 2010 and its impact on the effective tax rate during fiscal 2011.

Energy Marketing

Energy Marketing Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	**2011**	**2010**	**Increase (Decrease)**	**2011**	**2010**	**Increase (Decrease)**
Natural Gas (after Hedging)	$ 71,892	$ 72,759	$ (867)	$ 246,825	$ 302,931	$ (56,106)
Other	10	71	(61)	50	172	(122)
	$ 71,902	$ 72,830	$ (928)	$ 246,875	$ 303,103	$ (56,228)

Energy Marketing Volume

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2011	2010	Increase (Decrease)	2011	2010	Increase (Decrease)
Natural Gas (MMcf)	13,508	13,047	461	45,863	51,144	(5,281)

2011 Compared with 2010

Operating revenues for the Energy Marketing segment decreased $0.9 million and $56.2 million for the quarter and nine months ended June 30, 2011, as compared with the quarter and nine months ended June 30, 2010. The decrease for the quarter ended June 30, 2011 reflects a decline in gas sales revenue due to a lower average price of natural gas that was recovered through revenues, partially offset by an increase in volume sold to retail customers. The decrease for the nine months ended June 30, 2011 primarily reflects a decline in gas sales revenue due largely to a decrease in volume sold as well as a lower average price of natural gas that was recovered through revenues. The decrease in volume for the nine-month period is largely attributable to the non-recurrence of sales transactions undertaken at the Niagara pipeline delivery point to offset certain basis risks that the Energy Marketing segment was exposed to under certain fixed basis commodity purchase contracts for Appalachian production. The decrease in volume also reflects a decrease in volume sold to low-margin wholesale customers. Such transactions had the effect of increasing revenue and volume sold with minimal impact to earnings. The decrease in volume sold to wholesale customers during the nine-month period was partially offset by an increase in volume sold to retail customers.

The Energy Marketing segment s earnings for the quarter ended June 30, 2011 were $1.9 million, an increase of $0.5 million when compared with earnings of $1.4 million for the quarter ended June 30, 2010. The increase for the quarter was largely attributable to lower operating expenses of $0.3 million. This consisted primarily of a decrease in expense for anticipated U.S. Customs merchandise processing fees. The Energy Marketing segment also experienced a decrease in bad debt expense quarter over quarter. The Energy Marketing segment s earnings for the nine months ended June 30, 2011 were $9.1 million, an

-41-

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

increase of $0.6 million when compared with earnings of $8.5 million for the nine months ended June 30, 2010. This increase was largely attributable to higher margin of $0.3 million and lower operating costs of $0.1 million. The increase in margin was primarily driven by improved average margins per Mcf offset partially by a lower benefit from its contracts for storage capacity. The decrease in operating costs reflects the decrease in expense for U.S. Customs merchandise processing fees, discussed above, as well as lower bad debt expense. These decreases were partially offset by higher pension expense.

Corporate and All Other

2011 Compared with 2010

Corporate and All Other recorded earnings from continuing operations of $1.4 million for the quarter ended June 30, 2011, an increase of $1.3 million when compared with earnings from continuing operations of $0.1 million for the quarter ended June 30, 2010. The increase in earnings from continuing operations is due to lower interest expense of $2.4 million (primarily the result of lower borrowings at a lower interest rate due to the repayment of $200 million of 7.5% notes that matured in November 2010), lower depreciation and depletion expense of $1.3 million (due to a decrease in timber harvested as a result of the sale of the Company s timber harvesting and milling operations in September 2010) and higher gathering and processing revenues of $1.2 million (due to an increase in Midstream Corporation s gathering and processing activities). Lower income tax expense ($0.6 million) further contributed to the earnings increase as did a gain of $0.2 million resulting from the auction of some remaining timber mill equipment during the quarter ended June 30, 2011. The factors contributing to the overall increase in earnings were partially offset by lower interest income of $2.4 million (due to lower interest collected from the Company s Exploration and Production segment as a result of the aforementioned November 2010 debt repayment), higher property, franchise and other taxes of $0.9 million (due to an increase in capital stock tax expense recorded during the quarter ended June 30, 2011 related to fiscal year 2010) and lower margins of $0.7 million (due to a decrease in timber harvested as a result of the sale of the Company s timber harvesting and milling operations in September 2010). Additionally, the Company recorded a loss from unconsolidated subsidiaries of $0.1 million during the quarter ended June 30, 2011 compared to income of $0.4 million during the quarter ended June 30, 2010.

For the nine months ended June 30, 2011, Corporate and All Other had earnings from continuing operations of $32.0 million, an increase of $31.1 million when compared with earnings from continuing operations of $0.9 million for the nine months ended June 30, 2010. The increase in earnings from continuing operations is due to the gain on the sale of Horizon Power s investments in Seneca Energy and Model City of $31.4 million, lower interest expense of $6.0 million (primarily the result of lower borrowings at a lower interest rate due to the aforementioned November 2010 debt repayment), higher gathering and processing revenues of $3.8 million (due to an increase in Midstream Corporation s gathering and processing activities) and lower depreciation and depletion expense of $3.4 million (due to a decrease in timber harvested due to the sale of the Company s timber harvesting and milling operations in September 2010). Lower income tax expense ($0.6 million) further contributed to the earnings increase. Additionally, a $0.5 million gain on corporate-owned life insurance policies recorded during the quarter ended March 31, 2011 also factored into the increase. The gain of $0.2 million resulting from the auction of some remaining timber mill equipment, discussed above, and a $0.2 million gain resulting from the sale of Horizon Energy Development in the quarter ended December 31, 2010 also factored into the earnings increase. The factors contributing to the overall increase in earnings were partially offset by lower margins of $5.7 million (due to a decrease in timber harvested due to the sale of the Company s timber harvesting and milling operations in September 2010), lower interest income of $5.7 million (due to lower interest collected from the Company s Exploration and Production segment as a result of the aforementioned November 2010 debt repayment), higher property, franchise and other taxes of $1.2 million (due to an increase in capital stock tax expense recorded during the nine months ended June 30, 2011 related to fiscal year 2010) and higher operating expenses of $1.0 million (mostly due to the increase in Midstream Corporation s operating activities). Additionally, the Company recorded a loss from unconsolidated subsidiaries of $0.5 million during the quarter ended June 30, 2011 compared to income of $1.1 million during the quarter ended June 30, 2010.

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

Other Income

Other income increased $1.0 million for the quarter ended June 30, 2011 as compared with the quarter ended June 30, 2010. This increase is mainly attributable to a $0.5 million increase in allowance for funds used during construction in the Pipeline and Storage segment. In addition, there was a $0.3 million gain on disposal of some sawmill assets. For the nine months ended June 30, 2011, other income increased $2.3 million as compared with the nine months ended June 30, 2010. This increase is attributable to a $0.5 million gain on corporate-owned life insurance policies recognized during the second quarter and a $0.4 million gain on the sale of Horizon Energy Development recognized during the first quarter. In addition, there was a $0.9 million increase in allowance for funds used during construction in the Pipeline and Storage segment as well as a $0.3 million gain on the disposal of sawmill assets mentioned above.

Interest Expense on Long-Term Debt

Interest on long-term debt decreased $3.2 million for the quarter ended June 30, 2011 as compared with the quarter ended June 30, 2010. For the nine months ended June 30, 2011, interest on long-term debt decreased $9.2 million as compared with the nine months ended June 30, 2010. This decrease is primarily the result of a lower average amount of long-term debt outstanding and slightly lower average interest rates. The Company repaid $200 million of 7.5% notes that matured in November 2010.

Other Interest Expense

Other Interest expense decreased $0.7 million for the quarter ended June 30, 2011 as compared with the quarter ended June 30, 2010. The decrease is mainly due to lower interest expense on regulatory deferrals (primarily deferred gas costs) in the Utility segment. For the nine months ended June 30, 2011, other interest expense decreased $1.2 million as compared with the nine months ended June 30, 2010. The decrease in interest expense is mainly attributed to a decrease in interest expense on regulatory deferrals (primarily deferred gas costs) in the Utility segment. An increase in the allowance for borrowed funds used during construction also contributed to the decrease in interest expense.

CAPITAL RESOURCES AND LIQUIDITY

The Company s primary source 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. The Company s primary source of cash during the nine-month period ended June 30, 2010 consisted of cash provided by operating activities. This source of cash was supplemented by issues of new shares of common stock as a result of stock option exercises for the nine months ended June 30, 2010. During the nine months ended June 30, 2010, the common stock used to fulfill the requirements of the Company s 401(k) plans and Direct Stock Purchase and Dividend Reinvestment Plan 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, deferred income taxes, gain on the sale of unconsolidated subsidiaries, and income or loss from unconsolidated subsidiaries net of cash distributions.

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.

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

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 energy commodity price risk.

Net cash provided by operating activities totaled $536.3 million for the nine months ended June 30, 2011, an increase of $116.4 million compared with $419.9 million provided by operating activities for the nine months ended June 30, 2010. In the Exploration and Production segment, cash provided by operations increased due to higher cash receipts from the sale of natural gas production. An increase in hedging collateral deposits in the Exploration and Production segment at June 30, 2011 partly offset the increase in cash provided by operating activities. Hedging collateral deposits serve as collateral for open positions on exchange-traded futures contracts and over-the-counter swaps.

Investing Cash Flow

Expenditures for Long-Lived Assets

The Company s expenditures from continuing operations for long-lived assets totaled $549.7 million during the nine months ended June 30, 2011 and $341.9 million for the nine months ended June 30, 2010. The table below presents these expenditures:

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

(Millions)	2011	2010	Increase (Decrease)
Utility:			
Capital Expenditures	$ 39.4	$ 39.5	$ (0.1)
Pipeline and Storage:			
Capital Expenditures	75.0 (1)	22.2	52.8
Exploration and Production:			
Capital Expenditures	473.5 (1)(2)	273.8 (3)(4)	199.7
All Other:			
Capital Expenditures	6.8	6.4 (4)	0.4
Total Expenditures from Continuing Operations	$ 594.7	$ 341.9	$ 252.8

(1) Capital expenditures for the Exploration and Production segment include $60.7 million of accrued capital expenditures 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.

(2) Capital expenditures for the Exploration and Production segment for the nine months ended June 30, 2011 exclude $55.5 million of accrued 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 non-cash investing activities at that date. This amount has been included in the Consolidated Statement of Cash Flows at June 30, 2011.

Table of Contents

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

(3) Amount includes $24.3 million of accrued capital expenditures at June 30, 2010, the majority of which was in the Appalachian region. This amount has been excluded from the Consolidated Statement of Cash Flows at June 30, 2010 since it represents a non-cash investing activity at that date.

(4) Capital expenditures for the Exploration and Production segment for the nine months ended June 30, 2010 exclude $9.1 million of accrued capital expenditures, the majority of which was in the Appalachian region. Capital expenditures for All Other for the nine months ended June 30, 2010 exclude $0.7 million of accrued capital expenditures related to the construction of the Midstream Covington Gathering System. Both of these amounts were accrued at September 30, 2009 and paid during the nine months ended June 30, 2010. These amounts were excluded from the Consolidated Statement of Cash Flows at September 30, 2009 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, 2010.

Utility

The majority of the Utility capital expenditures for the nine months ended June 30, 2011 and June 30, 2010 were made for replacement of mains and main extensions, as well as for the replacement of service lines.

Pipeline and Storage

The majority of the Pipeline and Storage capital expenditures for 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, as discussed below. The Pipeline and Storage capital expenditure amounts for the nine months ended June 30, 2010 also include $5.8 million spent on the Lamont Phase I 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, 2011, the total amount reserved for the Pipeline and Storage segment s preliminary survey and investigation costs was $7.2 million.

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

Supply Corporation has signed a precedent agreement to provide 320,000 Dth/day of firm transportation capacity in conjunction with its Northern Access expansion project. Upon satisfaction of the conditions in the precedent agreement, Statoil Natural Gas LLC (Statoil) will enter into a 20-year firm transportation agreement for 320,000 Dth/day. This capacity will provide Statoil with a firm transportation path from the Tennessee Gas Pipeline (TGP) 300 Line at Ellisburg to the TransCanada Pipeline at Niagara. This path is attractive because it provides a route for Marcellus shale gas, principally along the TGP 300 Line in northern Pennsylvania, to be transported from the Marcellus supply basin to northern markets. Service is expected to begin in November 2012, and Supply Corporation filed an application for FERC authorization of the project on March 7, 2011. 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

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

compressor station in East Aurora, New York, along with other system enhancements including enhancements to the jointly owned Niagara Spur Loop Line. The preliminary cost estimate for the Northern Access expansion is $62 million. As of June 30, 2011, approximately $0.7 million has been spent on the Northern Access expansion project. The Company has determined that it is highly probable that this project will be built. Accordingly, previous reserves have been reversed and the $0.7 million has been capitalized as Construction Work in Progress.

Another expansion project involves new compression along Supply Corporation s Line N (Line N Expansion Project), increasing that line s capacity by 160,000 Dth/day into Texas Eastern s Holbrook Station (TETCO Holbrook) in southwestern Pennsylvania. The project will allow Marcellus production located in the vicinity of Line N to flow south and access markets off Texas Eastern s system, with a projected in-service date of September 2011. Two service agreements totaling 160,000 Dth/day of firm transportation have been executed. The FERC issued the NGA Section 7(c) certificate on December 16, 2010. Supply Corporation has accepted the certificate, received a FERC Notice to Proceed, and in February 2011 commenced construction. The preliminary cost estimate for the Line N Expansion Project is $20 million. As of June 30, 2011, approximately $11.8 million has been spent on the Line N expansion project, all of which has been capitalized as Construction Work in Progress.

Supply Corporation has also executed a precedent agreement for 150,000 Dth/day of additional capacity on Line N to TETCO Holbrook and has designed a project for this shipper to be ready 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 its integrity and reliability of its system and to create the additional capacity. The preliminary cost estimate for the Line N 2012 Expansion Project is approximately $30.0 million. As of June 30, 2011, approximately $0.2 million has been spent on the Line N 2012 Expansion Project, which has been included in preliminary survey and investigation charges and has been fully reserved for at June 30, 2011.

Following up on Supply Corporation s Lamont Project which went into service on June 15, 2010, a second Lamont expansion (Lamont Phase II Project) has been fully subscribed and is nearing completion. Supply Corporation has two executed service agreements for the full capacity of this project. Following construction of an additional 3,400 horsepower of compression, which began in March 2011, 10,000 Dth/day of incremental firm capacity was placed in service on July 1, 2011, and an additional 40,000 Dth/day will commence on October 1, 2011. The preliminary cost estimate for the Lamont Phase II Project is approximately $7.6 million. As of June 30, 2011, approximately $7.0 million has been spent on the Lamont Phase II project, all of which has been capitalized as Construction Work in Progress.

In addition, Supply Corporation continues to actively pursue its largest planned expansion, the West-to-East (W2E) pipeline project, which is designed to transport Rockies and/or locally produced natural gas supplies to the Ellisburg/Leidy/Corning area. Supply Corporation anticipates that the development of the W2E project will occur in phases. As currently envisioned, the first two 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. The project may be built in phases depending on the development of Marcellus production along the corridor, with the first facilities expected to go in service in late 2013 or late 2014.

Table of Contents

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

Following an Open Season that concluded on October 8, 2009, Supply Corporation executed precedent agreements to provide 125,000 Dth/day of firm transportation on the W2E Overbeck to Leidy project. Supply Corporation is pursuing post-Open Season capacity requests for the remaining capacity. On March 31, 2010, the FERC granted Supply Corporation s request for a pre-filing environmental review of the W2E Overbeck to Leidy project, and Supply Corporation is in the process of preparing an NGA Section 7(c) application. The capital cost of the W2E Overbeck to Leidy project is estimated to be $290 million. As of June 30, 2011, approximately $5.1 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, 2011.

Empire has executed service agreements for all 350,000 Dth/day of incremental firm transportation capacity in its Tioga County Extension Project. This project will transport Marcellus production from new interconnections at the southern terminus of a 15-mile extension of its Empire Connector line, in Tioga County, Pennsylvania. Empire s preliminary cost estimate for the Tioga County Extension Project is approximately $49 million. This project will enable 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 a planned new interconnection with TGP s 200 Line (Zone 5) in Ontario County, New York. On August 26, 2010, Empire filed an NGA Section 7(c) application to the FERC for approval of the project and the FERC issued the certificate on May 19, 2011. Empire has accepted the certificate, received a FERC Notice to Proceed and on July 7, 2011 commenced construction. Empire anticipates that these facilities will be placed in service on or before November 1, 2011. As of June 30, 2011, approximately $11.2 million has been spent related to the Tioga County Extension Project, all of which has been capitalized as Construction Work in Progress.

On December 17, 2010, Empire concluded an Open Season for up to 260,000 Dth per 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 evaluating the substantial market interest resulting from this Open Season, which was for more than 260,000 Dth per day of capacity, and is studying the facility design that would be necessary to provide the requested service. 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, 2011, approximately $0.1 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, 2011.

The Company anticipates financing the Line N Expansion Projects, the Lamont Phase II Project, the Northern Access expansion project, the W2E Overbeck to Leidy project, and the Tioga County Extension Projects, all of which are discussed above, with a combination of cash from operations, short-term debt, and long-term debt. The Company had $184.7 million in Cash and Temporary Cash Investments at June 30, 2011, as shown on the Company s Consolidated Balance Sheet. The Company expects to use cash from operations as the first means of financing these projects, with short-term debt providing temporary financing when needed. The Company may issue some long-term debt in conjunction with these projects in the later part of fiscal 2011 or in fiscal 2012.

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

Exploration and Production

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. These amounts included approximately $165.5 million spent to develop proved undeveloped reserves. The capital expenditures in the Appalachian region include 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.

As the Company has been accelerating its Marcellus Shale development, it has been decreasing its emphasis in the Gulf Coast region. In March 2011, the Company entered into a purchase and sale agreement to sell its off-shore oil and natural gas properties in the Gulf of Mexico effective as of January 1, 2011 for approximately $70 million and received a deposit of $7.0 million from the purchaser. The Company completed the sale in April 2011, receiving an additional $54.8 million. The difference between the total proceeds received of $61.8 million and the sale price of $70.0 million represents a purchase price adjustment for the operating cash flow that the Company recorded from January 1, 2011 to the closing date of the sale. Under the full cost method of accounting for oil and natural gas properties, the sale proceeds were accounted for as a reduction of capitalized costs in April 2011. 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 $7.7 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 in May 2011. 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.

The Exploration and Production segment capital expenditures for the nine months ended June 30, 2010 were primarily well drilling and completion expenditures and included approximately $240.6 million for the Appalachian region (including $217.6 million in the Marcellus Shale area), $21.2 million for the West Coast region and $12.0 million for the Gulf Coast region, the majority of which was for the off-shore program in the shallow waters of the Gulf of Mexico. These amounts included approximately $23.4 million spent to develop proved undeveloped reserves. The capital expenditures in the Appalachian region include the Company s acquisition of two tracts of leasehold acreage for approximately $71.8 million. The Company acquired these tracts in order to expand its Marcellus Shale acreage holdings. These tracts, consisting of approximately 18,000 net acres in Tioga and Potter Counties in Pennsylvania, are geographically similar to the Company s existing Marcellus Shale acreage in the area. The transaction closed on March 12, 2010.

All Other

The majority of the All Other category s capital expenditures for the nine months ended June 30, 2011 were primarily for expansion of Midstream Corporation s Covington Gathering system in Tioga County, Pennsylvania as well as for the construction of Midstream Corporation s Trout Run Gathering System, as discussed below. The majority of the All Other category s capital expenditures for the nine months ended June 30, 2010 were for the construction of Midstream Corporation s Covington 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, called the Trout Run Gathering System, is anticipated to be placed in service in late 2011. The system will consist of approximately 16.5 miles of backbone gathering system at a cost of $51 million. As of June 30, 2011, the Company has spent approximately $3.3 million in costs related to this project.

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

The Company anticipates funding the Trout Run Gathering System project with cash from operations and/or short-term borrowings. Given the Company s cash position at June 30, 2011, the Company expects to use cash from operations as the first means of financing these projects.

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 gas transmission line capacities. While the majority of capital expenditures in the Utility segment are necessitated by the continued need for replacement and upgrading of mains and service lines, the magnitude of future capital expenditures or other investments in the Company s other business segments depends, to a large degree, upon market conditions.

Financing Cash Flow

The Company did not have any outstanding short-term notes payable to banks or commercial paper at June 30, 2011. During the nine months ended June 30, 2011, consolidated short-term debt did not exceed $31.5 million outstanding. 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, and other working capital needs. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt.

As for bank loans, the Company maintains a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under these lines of credit are made at competitive market rates. These credit lines, which aggregate to $385.0 million, are revocable at the option of the financial institutions and are reviewed on an annual basis. The Company anticipates that these lines of credit will continue to be renewed, or substantially replaced by similar lines.

The total amount available to be issued under the Company s commercial paper program is $300.0 million. The commercial paper program is backed by a syndicated committed credit facility totaling $300.0 million, which commitment extends through September 30, 2013. Under the Company s committed credit facility, the Company has agreed that its debt to capitalization ratio will not exceed .65 at the last day of any fiscal quarter through September 30, 2013. At June 30, 2011, the Company s debt to capitalization ratio (as calculated under the facility) was .36. The constraints specified in the committed credit facility would permit an additional $2.39 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 would exceed .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, 2011, the Company would have been permitted to issue up to a maximum of $1.71 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 9.4%) of the Company s long-term debt (as of June 30, 2011) 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

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

agreement, or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

The Company s $300.0 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, 2011, the Company did not have any debt outstanding under the committed credit facility.

The Company s embedded cost of long-term debt was 6.85% at June 30, 2011 and 6.95% at June 30, 2010. If the Company were to issue 10-year long-term debt today, its borrowing costs might be expected to be in the range of 4.75% to 5.25%.

Current Portion of Long-Term Debt at June 30, 2011 consists of $150 million of 6.70% medium-term notes that mature in November 2011. Currently, the Company expects to refund these medium-term notes in November 2011 with cash on hand, short-term borrowings and/or long-term debt. In November 2010, the Company repaid $200 million of 7.50% notes that matured on November 22, 2010 that were classified as Current Portion of Long-Term Debt at September 30, 2010.

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 Utility and the Pipeline and Storage segments, having a remaining lease commitment of approximately $23.8 million. These leases have been entered into for the use of buildings, vehicles, construction tools, 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, 2011, the Company contributed $40.0 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 2011, the Company expects to contribute between $8.0 and $9.0 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 2011 in order to be in compliance with the Pension Protection Act of 2006. In the remainder of 2011, the Company expects to contribute between $1.0 and $6.5 million to its VEBA trusts and 401(h) accounts.

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

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 the Company should be categorized as a non-financial end user of derivatives, that is, as a non-financial entity that uses derivatives to hedge commercial risk. Nevertheless, the 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 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 $50.5 million at June 30, 2011 and represent 27.3% of the Total Net Assets shown in Part I, Item 1 at Note 2 Fair Value Measurements at June 30, 2011.

The increase in the net fair value liability of the Level 3 positions from October 1, 2010 to June 30, 2011, 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, 2011.

The fair value of all of the Company s Net Derivative Asset was reduced by $0.3 million 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 2010 Form 10-K. There have been no subsequent material changes to the Company s exposure to market risk sensitive instruments.

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

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 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 largely 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 currently does not have a rate case on file with the FERC. The rate settlement approved by the FERC on February 9, 2007 requires Supply Corporation to make a general rate filing to be effective December 1, 2011, and bars Supply Corporation from making a general rate filing before then, with some exceptions specified in the settlement.

Empire s new facilities (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 Certificate of Public Convenience and Necessity requires 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.

Table of Contents

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

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. The Company has received approval from the NYDEC of a Remedial Design work plan for this site and has recorded an estimated minimum liability for remediation of this site of $14.5 million.

At June 30, 2011, 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 $17.2 million to $21.4 million. The minimum estimated liability of $17.2 million, which includes the $14.5 million discussed above, has been recorded on the Consolidated Balance Sheet at June 30, 2011. 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. In April 2011, the U.S. Senate rejected bills aimed at curbing the authority of the EPA to regulate greenhouse gas emissions. 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. 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. 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 will be effective as of the Company s second quarter of fiscal 2012. The Company is currently evaluating the impact that adoption of this authoritative guidance will have on its consolidated financial statement disclosures.

Table of Contents

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

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 to 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, will, may, and similar expressions, are forward-looking 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 forward-looking statements contained herein are based on various assumptions, many of which are based, in turn, upon further assumptions. The Company s expectations, beliefs and projections are expressed in good faith and are believed by the Company to have a reasonable basis, including, without limitation, management s examination of historical operating trends, data contained in the Company s records and other data available from third parties, 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. 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;

2. 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;

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

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

5. 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, 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;

Table of Contents

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

6. Changes in laws and regulations to which the Company is subject, including those involving derivatives, taxes, safety, employment, climate change, other environmental matters, and exploration and production activities such as hydraulic fracturing;

7. Uncertainty of oil and gas reserve estimates;

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

9. Significant changes in market dynamics or competitive factors affecting the Company s ability to retain existing customers or obtain new customers;

10. Changes in demographic patterns and weather conditions;

11. Changes in the availability and/or price of natural gas or oil and the effect of such changes on the accounting treatment of derivative financial instruments;

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

13. Changes in the availability and/or price of derivative financial instruments;

14. 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;

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

16. Changes in the projected profitability of pending or potential projects, investments or transactions;

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

18. 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;

19. Governmental/regulatory actions, initiatives and proceedings, including those involving derivatives, acquisitions, financings, rate cases (which address, among other things, allowed rates of return, rate design and retained natural gas), affiliate relationships, industry structure,

franchise renewal, and environmental/safety requirements;

20. Unanticipated impacts of restructuring initiatives in the natural gas and electric industries;

21. Ability to successfully identify and finance acquisitions or other investments and ability to operate and integrate existing and any subsequently acquired business or properties;

22. Changes in 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;

23. Significant changes in tax rates or policies or in rates of inflation or interest;

24. Significant changes in the Company s relationship with its employees or contractors and the potential adverse effects if labor disputes, grievances or shortages were to occur;

25. Changes in accounting principles or the application of such principles to the Company;

Table of Contents

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

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

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

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

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

Industry and Market Information

The industry and market data used or referenced in this report are based on independent industry publications, government publications, reports by market research firms or other published independent sources. Some industry and market data may also be based on good faith estimates, which are derived from the Company s review of internal information, as well as the independent sources listed above. Independent industry publications and surveys generally state that they have obtained information from sources believed to be reliable, but do not guarantee the accuracy and completeness of such information. While the Company believes that each of these studies and publications is reliable, the Company has not independently verified such data and makes no representation as to the accuracy of such information. Forecasts in particular may prove to be inaccurate, especially over long periods of time. Similarly, while the Company believes its internal information is reliable, such information has not been verified by any independent sources, and the Company makes no assurances that any predictions contained herein will prove to be accurate.

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, 2011.

Changes in Internal Controls Over Financial Reporting

There were no changes in the Company s internal control over financial reporting that occurred during the quarter ended June 30, 2011 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Table of Contents

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 normal-course matters could have a material effect on earnings and cash flows in the quarterly and annual period in which they are resolved, they are not expected to change materially the Company s present liquidity position, nor are they expected to have a material adverse effect on the financial condition of the Company.

Item 1A. Risk Factors

The risk factors in Item 1A of the Company s 2010 Form 10-K, as amended by Item 1A of Part II of the Company s Forms 10-Q for the quarters ended December 31, 2010 and March 31, 2011, have not materially changed.

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

On April 1, 2011, the Company issued a total of 4,050 unregistered shares of Company common stock to the nine non-employee directors of the Company then serving on the Board of Directors of the Company, 450 shares to each such director. All of these unregistered shares were issued under the Company s 2009 Non-Employee Director Equity Compensation Plan as partial consideration for such directors services during the quarter ended June 30, 2011. 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, 2011	131,782	$ 74.38		6,971,019
May 1 - 31, 2011	6,269	$ 68.66		6,971,019
June 1 - 30, 2011	10,980	$ 69.49		6,971,019
Total	149,031	$ 73.78		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, 2011, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program. Of the 149,031 shares purchased other than through a publicly announced share repurchase program, 18,425 were purchased for the Company s 401(k) plans and 130,606 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.

Table of Contents

Item 6. Exhibits

Exhibit Number	Description of Exhibit
12	Statements regarding Computation of Ratios:
	Ratio of Earnings to Fixed Charges for the Twelve Months Ended June 30, 2011 and the Fiscal Years Ended September 30, 2007 through 2010.
31.1	Written statements of Chief Executive Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934.
31.2	Written statements of Principal Financial Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934.
32	Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99	National Fuel Gas Company Consolidated Statements of Income for the Twelve Months Ended June 30, 2011 and 2010.
101	Interactive data files 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, 2011 and 2010, (ii) the Consolidated Balance Sheets at June 30, 2011 and September 30, 2010, (iii) the Consolidated Statements of Cash Flows for the nine months ended June 30, 2011 and 2010, (iv) the Consolidated Statements of Comprehensive Income for the three and nine months ended June 30, 2011 and 2010 and (v) the Notes to Condensed Consolidated Financial Statements.

Table of Contents

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 9, 2011