NATIONAL FUEL GAS CO
Form 10-Q
February 04, 2011

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-Q

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

For the quarterly period ended December 31, 2010

OR

o **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 þ NO o

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

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

Large Accelerated Filer þ	Accelerated Filer o	Non-Accelerated Filer o (Do not check if a smaller reporting company)	Smaller Reporting Company o

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

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 January 31, 2011: 82,345,955 shares.

GLOSSARY OF TERMS

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

National Fuel Gas Companies	
Company	The Registrant, the Registrant and its subsidiaries or the Registrant s subsidiaries as appropriate in the context of the disclosure
Distribution Corporation	National Fuel Gas Distribution Corporation
Empire	Empire Pipeline, Inc.
ESNE	Energy Systems North East, LLC
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
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.
Dth	Decatherm; one Dth of natural gas has a heating value of 1,000,000 British thermal units, approximately equal to the heating value of 1 Mcf of natural gas.
Exchange Act	Securities Exchange Act of 1934, as amended

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GLOSSARY OF TERMS (Cont.)

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 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.

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

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The Company has nothing to report under this item.

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

This Form 10-Q contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Forward-looking statements should be read with the cautionary statements and important factors included in this Form 10-Q at Item 2 MD&A, under the heading Safe Harbor for Forward-Looking Statements. Forward-looking statements are all statements other than statements of historical fact, including, without limitation, statements regarding future prospects, plans, objectives, goals, projections, estimates of oil and gas quantities, strategies, future events or performance and underlying assumptions, capital structure, anticipated capital expenditures, completion of construction and other projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words anticipates, estimates, expects, forecasts intends, plans, predicts, projects, believes, seeks, will, may, and similar expressions.

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Part I. Financial Information

Item 1. Financial Statements

National Fuel Gas Company
Consolidated Statements of Income and Earnings
Reinvested in the Business
(Unaudited)

	Three Months Ended December 31, 2010	Three Months Ended December 31, 2009
(Thousands of Dollars, Except Per Common Share Amounts)		
INCOME		
Operating Revenues	$ 450,948	$ 454,135
Operating Expenses		
Purchased Gas	163,038	171,290
Operation and Maintenance	97,450	93,770
Property, Franchise and Other Taxes	19,736	18,650
Depreciation, Depletion and Amortization	53,313	44,788
	333,537	328,498
Operating Income	117,411	125,637
Other Income (Expense):		
Income (Loss) from Unconsolidated Subsidiaries	(1,100)	401
Interest Income	884	1,154
Other Income	993	356
Interest Expense on Long-Term Debt	(20,192)	(22,063)
Other Interest Expense	(1,401)	(1,377)
Income from Continuing Operations Before Income Taxes	96,595	104,108
Income Tax Expense	38,052	39,883
Income from Continuing Operations	58,543	64,225
Income from Discontinued Operations, Net of Tax		274
Net Income Available for Common Stock	58,543	64,499
EARNINGS REINVESTED IN THE BUSINESS		
Balance at October 1	1,063,262	948,293
	1,121,805	1,012,792
Dividends on Common Stock (2010 - $0.345 per share; 2009 - $0.335 per share)	(28,407)	(27,129)

Balance at December 31	$ 1,093,398	$ 985,663
Earnings Per Common Share:		
Basic:		
Income from Continuing Operations	$ 0.71	$ 0.80
Income from Discontinued Operations		
Net Income Available for Common Stock	$ 0.71	$ 0.80
Diluted:		
Income from Continuing Operations	$ 0.70	$ 0.78
Income from Discontinued Operations		
Net Income Available for Common Stock	$ 0.70	$ 0.78
Weighted Average Common Shares Outstanding:		
Used in Basic Calculation	82,223,428	80,612,303
Used in Diluted Calculation	83,420,351	82,172,649

See Notes to Condensed Consolidated Financial Statements

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Item 1. Financial Statements (Cont.)

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	December 31, 2010	September 30, 2010
ASSETS		
Property, Plant and Equipment	$ 5,837,365	$ 5,637,498
Less Accumulated Depreciation, Depletion and Amortization	2,236,152	2,187,269
	3,601,213	3,450,229
Current Assets		
Cash and Temporary Cash Investments	79,622	395,171
Cash Held in Escrow		2,000
Hedging Collateral Deposits	31,446	11,134
Receivables Net of Allowance for Uncollectible Accounts of $35,870 and $30,961, Respectively	147,829	132,136
Unbilled Utility Revenue	59,211	20,920
Gas Stored Underground	47,839	48,584
Materials and Supplies at average cost	31,560	24,987
Other Current Assets	107,201	115,969
Deferred Income Taxes	20,901	24,476
	525,609	775,377
Other Assets		
Recoverable Future Taxes	150,865	149,712
Unamortized Debt Expense	12,036	12,550
Other Regulatory Assets	534,146	542,801
Deferred Charges	10,219	9,646
Other Investments	80,701	77,839
Investments in Unconsolidated Subsidiaries	13,728	14,828
Goodwill	5,476	5,476
Fair Value of Derivative Financial Instruments	46,152	65,184
Other	1,836	1,983
	855,159	880,019
Total Assets	$ 4,981,981	$ 5,105,625

See Notes to Condensed Consolidated Financial Statements

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Item 1. Financial Statements (Cont.)

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	December 31, 2010	September 30, 2010
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders Equity		
Common Stock, $1 Par Value Authorized - 200,000,000 Shares; Issued and Outstanding - 82,338,454 Shares and 82,075,470 Shares, Respectively	$ 82,338	$ 82,075
Paid in Capital	643,856	645,619
Earnings Reinvested in the Business	1,093,398	1,063,262
Total Common Shareholder Equity Before Items of Other Comprehensive Loss	1,819,592	1,790,956
Accumulated Other Comprehensive Loss	(64,650)	(44,985)
Total Comprehensive Shareholders Equity	1,754,942	1,745,971
Long-Term Debt, Net of Current Portion	899,000	1,049,000
Total Capitalization	2,653,942	2,794,971
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper	20,500	
Current Portion of Long-Term Debt	150,000	200,000
Accounts Payable	181,564	145,223
Amounts Payable to Customers	23,914	38,109
Dividends Payable	28,407	28,316
Interest Payable on Long-Term Debt	15,953	30,512
Customer Advances	27,633	27,638
Customer Security Deposits	18,508	18,320
Other Accruals and Current Liabilities	30,838	16,046
Fair Value of Derivative Financial Instruments	34,500	20,160
	531,817	524,324
Deferred Credits		
Deferred Income Taxes	821,001	800,758
Taxes Refundable to Customers	69,589	69,585
Unamortized Investment Tax Credit	3,112	3,288
Cost of Removal Regulatory Liability	125,862	124,032
Other Regulatory Liabilities	88,263	89,334

Pension and Other Post-Retirement Liabilities	433,010	446,082
Asset Retirement Obligations	100,580	101,618
Other Deferred Credits	154,805	151,633
	1,796,222	1,786,330
Commitments and Contingencies		
Total Capitalization and Liabilities	$ 4,981,981	$ 5,105,625

See Notes to Condensed Consolidated Financial Statements

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Item 1. Financial Statements (Cont.)

National Fuel Gas Company
Consolidated Statements of Cash Flows
(Unaudited)

	Three Months Ended December 31,	
(Thousands of Dollars)	2010	2009
OPERATING ACTIVITIES		
Net Income Available for Common Stock	$ 58,543	$ 64,499
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Depreciation, Depletion and Amortization	53,313	44,955
Deferred Income Taxes	36,600	21,092
(Income) Loss from Unconsolidated Subsidiaries, Net of Cash Distributions	1,100	1,599
Excess Tax Benefits Associated with Stock-Based Compensation Awards		(13,437)
Other	2,443	7,958
Change in:		
Hedging Collateral Deposits	(20,312)	(244)
Receivables and Unbilled Utility Revenue	(53,984)	(67,882)
Gas Stored Underground and Materials and Supplies	(5,828)	2,839
Prepayments and Other Current Assets	8,768	17,859
Accounts Payable	29,246	11,408
Amounts Payable to Customers	(14,195)	(11,310)
Customer Advances	(5)	6,098
Customer Security Deposits	188	2,135
Other Accruals and Current Liabilities	1,387	(13,536)
Other Assets	(10,463)	16,967
Other Liabilities	670	(22,667)
Net Cash Provided by Operating Activities	87,471	68,333
INVESTING ACTIVITIES		
Capital Expenditures	(192,052)	(62,205)
Investment in Subsidiary, Net of Cash Acquired	(1,750)	
Cash Held in Escrow	2,000	
Other	(298)	(247)
Net Cash Used in Investing Activities	(192,100)	(62,452)
FINANCING ACTIVITIES		
Changes in Notes Payable to Banks and Commercial Paper	20,500	
Excess Tax Benefits Associated with Stock-Based Compensation Awards		13,437
Reduction of Long-Term Debt	(200,000)	
Dividends Paid on Common Stock	(28,316)	(26,967)

Net Proceeds from Issuance (Repurchase) of Common Stock	(3,104)	3,997
Net Cash Used in Financing Activities	(210,920)	(9,533)
Net Decrease in Cash and Temporary Cash Investments	(315,549)	(3,652)
Cash and Temporary Cash Investments at October 1	395,171	408,053
Cash and Temporary Cash Investments at December 31	$ 79,622	$ 404,401

See Notes to Condensed Consolidated Financial Statements

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Item 1. Financial Statements (Cont.)

National Fuel Gas Company
Consolidated Statements of Comprehensive Income
(Unaudited)

(Thousands of Dollars)	Three Months Ended December 31, 2010	2009
Net Income Available for Common Stock	$ 58,543	$ 64,499
Other Comprehensive Income (Loss), Before Tax:		
Foreign Currency Translation Adjustment	17	17
Reclassification Adjustment for Realized Foreign Currency Translation Loss in Net Income	34	
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	2,540	(713)
Unrealized Loss on Derivative Financial Instruments Arising During the Period	(27,136)	(4,853)
Reclassification Adjustment for Realized Gains on Derivative Financial Instruments in Net Income	(9,053)	(12,052)
Other Comprehensive Loss, Before Tax	(33,598)	(17,601)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	960	(271)
Income Tax Benefit Related to Unrealized Loss on Derivative Financial Instruments Arising During the Period	(11,168)	(2,062)
Reclassification Adjustment for Income Tax Expense on Realized Gains from Derivative Financial Instruments In Net Income	(3,725)	(4,962)
Income Taxes Net	(13,933)	(7,295)
Other Comprehensive Loss	(19,665)	(10,306)
Comprehensive Income	$ 38,878	$ 54,193

See Notes to Condensed Consolidated Financial Statements

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 its majority owned entities. The equity method is used to account for minority owned entities. 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.

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 three months ended December 31, 2010 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 investments purchased with a maturity of generally three months or less to be cash equivalents.

At December 31, 2010, 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 $2.0 million of capital expenditures in the Pipeline and Storage segment at December 31, 2010. These amounts were excluded from the Consolidated Statement of Cash Flows at December 31, 2010 since they represent non-cash investing activities at that date.

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 quarter ended December 31, 2010.

At December 31, 2009, the Company accrued $15.4 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 December 31, 2009 since it represented a non-cash investing activity at that date.

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Item 1. Financial Statements (Cont.)

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 at September 30, 2009. 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 quarter ended December 31, 2009.

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 December 31, 2010, the Company had hedging collateral deposits of $6.6 million related to its exchange-traded futures contracts and $24.8 million related to its over-the-counter crude oil swap agreements. In accordance with its accounting policy, the Company does not offset hedging collateral deposits paid or received against related derivative financial instruments liability or asset balances.

Cash Held in Escrow. On July 20, 2009, the Company s wholly-owned subsidiary in the Exploration and Production segment, Seneca, acquired Ivanhoe Energy s United States oil and gas operations for approximately $39.2 million in cash (including cash acquired of $4.3 million). The cash acquired at acquisition included $2 million held in escrow. Seneca placed this amount in escrow as part of the purchase price. In December 2010, the Company and Ivanhoe Energy negotiated a final settlement agreement in which Ivanhoe Energy was entitled to $1.75 million and the Company was entitled to $0.25 million of the cash held in escrow. For presentation purposes on the Consolidated Statement of Cash Flows, the Cash Held in Escrow line item within Investing Activities for the three months ended December 31, 2010 reflects the fact that $2.0 million is no longer held in escrow at December 31, 2010. The Investment in Subsidiary, Net of Cash Acquired line item within Investing Activities for the three months ended December 31, 2010 reflects the $1.75 million paid to Ivanhoe Energy.

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 $17.1 million at December 31, 2010, 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 $184.0 million and $151.2 million at December 31, 2010 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.

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

Item 1. Financial Statements (Cont.)

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 December 31, 2010) 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 December 31, 2010, 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 December 31, 2010.

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

	At December 31, 2010	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	11,580	32,876
Net Unrealized Gain on Securities Available for Sale	3,235	1,655
Accumulated Other Comprehensive Loss	$ (64,650)	$ (44,985)

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

	At December 31, 2010	At September 30, 2010
Prepayments	$ 10,873	$ 13,884
Prepaid Property and Other Taxes	14,782	12,413
Federal Income Taxes Receivable	56,287	56,334
State Income Taxes Receivable	15,593	18,007
Fair Values of Firm Commitments	9,666	15,331
	$ 107,201	$ 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 23,478 and 24,000 SARs excluded as being antidilutive for the quarters ended December 31, 2010 and 2009, respectively. For the quarters ended December 31, 2010 and 2009, there were no stock options or restricted stock units excluded as being antidilutive.

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Item 1. Financial Statements (Cont.)

Stock-Based Compensation. During the quarter ended December 31, 2010, 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. The non-performance based SARs granted during the quarter ended December 31, 2010 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 quarter ended December 31, 2010 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 ended December 31, 2010. 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 quarter ended December 31, 2010. The weighted average fair value of such restricted shares was $63.98 per share. In addition, the Company granted 28,900 restricted stock units during the quarter ended December 31, 2010. The weighted average fair value of such restricted stock units was $58.23 per share. 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 June 2009, the FASB issued amended authoritative guidance to improve and clarify financial reporting requirements by companies involved with variable interest entities. The new guidance requires a company to perform an analysis to determine whether the company s variable interest or interests give it a controlling financial interest in a variable interest entity. The analysis also assists in identifying the primary beneficiary of a variable interest entity. This authoritative guidance became effective for the quarter ended December 31, 2010. Given the current organizational structure of the Company, the Company s consolidated financial statements were not impacted by this guidance.

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 December 31, 2010 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.

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Item 1. Financial Statements (Cont.)

Recurring Fair Value Measures	At fair value as of December 31, 2010			
(Thousands of Dollars)	Level 1	Level 2	Level 3	Total
||||				
Assets:				
Cash Equivalents Money Market Mutual Funds	$ 47,674	$	$	$ 47,674
Derivative Financial Instruments:				
Over the Counter Swaps Oil		(392)		(392)
Over the Counter Swaps Gas		46,544		46,544
Other Investments:				
Balanced Equity Mutual Fund	18,280			18,280
Common Stock Financial Services Industry	6,789			6,789
Other Common Stock	257			257
Hedging Collateral Deposits	31,446			31,446
Total	$ 104,446	$ 46,152	$	$ 150,598
Liabilities:				
Derivative Financial Instruments:				
Commodity Futures Contracts Gas	$ 3,125	$	$	$ 3,125
Over the Counter Swaps Oil			37,407	37,407
Over the Counter Swaps Gas		(6,032)		(6,032)
Total	$ 3,125	$ (6,032)	$ 37,407	$ 34,500
Total Net Assets/(Liabilities)	$ 101,321	$ 52,184	$ (37,407)	$ 116,098

Recurring Fair Value Measures	At fair value as of September 30, 2010			
(Thousands of Dollars)	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

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Item 1. Financial Statements (Cont.)

Derivative Financial Instruments

At December 31, 2010 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 $6.6 million (at December 31, 2010) 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 December 31, 2010 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 these 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 December 31, 2010 and all of its crude oil price swap agreements at September 30, 2010. Hedging collateral deposits of $24.8 million and $1.0 million associated with these crude oil price swap agreements have been reported in Level 1 at December 31, 2010 and September 30, 2010, respectively. The fair value of the 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 $0.5 million and $1.0 million at December 31, 2010 and September 30, 2010, respectively. The fair market value of the price swap agreements reported as Level 3 liabilities at December 31, 2010 have been reduced by less than $0.1 million and the price swap agreements reported as Level 2 and Level 3 liabilities at September 30, 2010 have been reduced by $0.3 million based on an assessment of the Company s credit risk. These credit reserves were determined by applying default probabilities to the anticipated cash flows that the Company is either expecting from its counterparties or expecting to pay to its counterparties.

The tables listed below provide reconciliations of the beginning and ending net balances for assets and liabilities measured at fair value and classified as Level 3 for the quarters ended December 31, 2010 and 2009, respectively. For the quarter ended December 31, 2010, no transfers in or out of Level 1 or Level 2 occurred.

Fair Value Measurements Using Unobservable Inputs (Level 3)

		Total Gains/Losses Realized and Unrealized			
(Dollars in thousands)	October 1, 2010	Included in Earnings	Included in Other Comprehensive Income	Transfer In/Out of Level 3	December 31, 2010
Derivative Financial Instruments[2]	$ (16,483)	$ (2,803)[1]	$ (18,121)	$	$ (37,407)

[1] Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the three months ended December 31, 2010.

[2] Derivative Financial Instruments are shown on a net basis.

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Item 1. Financial Statements (Cont.)

Fair Value Measurements Using Unobservable Inputs (Level 3)

(Dollars in thousands)	October 1, 2009	Total Gains/Losses Realized and Unrealized: Included in Earnings	Total Gains/Losses Realized and Unrealized: Included in Other Comprehensive Income	Transfer In/Out of Level 3	December 31, 2009
Derivative Financial Instruments[2]	$ 26,969	$ (3,135)[1]	$ (23,983)	$	$ (149)

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the three months ended December 31, 2009.

(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):

	December 31, 2010		September 30, 2010	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-Term Debt	$ 1,049,000	$ 1,196,215	$ 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 $55.4 million at December 31, 2010 and September 30, 2010. The fair value of the equity mutual fund was $18.3 million at December 31, 2010 and $17.3 million at September 30, 2010. The gross unrealized gain on this equity mutual fund was $0.7 million at December 31, 2010. 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 $6.8 million at December 31, 2010 and $5.0 million at September 30, 2010. The gross unrealized gain on this stock was $4.4 million at December 31, 2010 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 Company s hedges do not typically exceed 3 years.

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Item 1. Financial Statements (Cont.)

The Company has presented its net derivative assets and liabilities on its Consolidated Balance Sheets at December 31, 2010 and September 30, 2010 as shown in the table below.

Fair Values of Derivative Instruments
(Dollar Amounts in Thousands)

Derivatives Designated as Hedging Instruments	Asset Derivatives: Consolidated Balance Sheet Location	Asset Derivatives: Fair Value	Liability Derivatives: Consolidated Balance Sheet Location	Liability Derivatives: Fair Value
Commodity Contracts at December 31, 2010	Fair Value of Derivative Financial Instruments	$ 46,152	Fair Value of Derivative Financial Instruments	$ 34,500
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 December 31, 2010 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 December 31, 2010	$ 58,315	$ 46,663
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.

As of December 31, 2010, 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	41.9 Bcf (all short positions)
Crude Oil	2,727,000 Bbls (all short positions)

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As of December 31, 2010, 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	5.5 Bcf (4.2 Bcf short positions (forecasted storage withdrawals) and 1.3 Bcf long positions (forecasted storage injections))

As of December 31, 2010, 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	0.3 Bcf (all short positions)

As of December 31, 2010, the Company s Exploration and Production segment had $13.3 million ($7.9 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that $10.3 million ($6.1 million after tax) of these gains will be reclassified into the Consolidated Statement of Income within the next 12 months as the expected sales of the underlying commodities occur. See Note 1, under Accumulated Other Comprehensive Income (Loss), for the after-tax gain 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).

As of December 31, 2010, the Company s Energy Marketing segment had $6.2 million ($3.8 million after tax) of net hedging gains included in the accumulated other comprehensive income (loss) balance. It is expected that $6.1 million ($3.7 million after tax) of these gains will be reclassified into the Consolidated Statement of Income 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 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).

As of December 31, 2010, the Company s Pipeline and Storage segment had $0.1 million (less than $0.1 million after tax) of net hedging losses included in the accumulated other comprehensive income (loss) balance. It is expected that the full amount will be reclassified into the Consolidated Statement of Income within the next 12 months as the expected sales of the underlying commodities occur. See Note 1, under Accumulated Other Comprehensive Income (Loss), for the after-tax gain 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).

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Item 1. Financial Statements (Cont.)

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Three Months Ended December 31, 2010 and 2009 (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 December 31, 2010	2009	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 December 31, 2010	2009	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 December 31, 2010	2009
Commodity Contracts Exploration & Production segment	$ (26,781)	$ (7,910)	Operating Revenue	$ 9,007	$ 12,040	Operating Revenue	$	$
Commodity Contracts Energy Marketing segment	$ (269)	$ 3,024	Purchased Gas	$ 46	$ 23	Operating Revenue	$	$
Commodity Contracts Pipeline & Storage segment	$ (86)	$ 33	Operating Revenue	$	$ (11)	Operating Revenue	$	$
Total	$ (27,136)	$ (4,853)		$ 9,053	$ 12,052		$	$

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 December 31, 2010, the Company s Energy Marketing segment had fair value hedges covering approximately 12.4 Bcf (11.5 Bcf of fixed price sales commitments (all long

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positions), 0.8 Bcf of fixed price purchase commitments (all short positions), and 0.1 Bcf of commitments related to the withdrawal of storage gas (all short positions)). For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting gain or loss on the hedged item attributable to the hedged risk completely offset each other in current earnings, as shown below.

Consolidated Statement of Income	Gain/(Loss) on Derivative	Gain/(Loss) on Commitment
Operating Revenues	$ 7,511,054	$ (7,511,054)
Purchased Gas	$ (841,956)	$ 841,956

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 Three Months Ended December 31, 2010 (In thousands)
Commodity Contracts (1)	Energy Marketing segment	Operating Revenues	$ 7,511
Commodity Contracts (2)	Energy Marketing segment	Purchased Gas	$ (649)
Commodity Contracts (3)	Energy Marketing segment	Purchased Gas	$ (192)
			$ 6,670

(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 $5.1 million of credit exposure per counterparty in a gain position at December 31, 2010. The maximum credit exposure per counterparty in a gain position at December 31, 2010 was $9.2 million. The Company had not received any collateral from these counterparties at December 31, 2010 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.

As of December 31, 2010, nine 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 December 31, 2010, the fair market value of the derivative financial instrument assets with a credit-risk related contingency feature was $27.5 million according to the Company s internal model (discussed in Note 2 Fair Value Measurements). At December 31, 2010, the fair market value of the derivative financial instrument liabilities with a credit-risk related contingency feature was $31.4 million according to the Company s internal model (discussed in

Item 1. Financial Statements (Cont.)

Note 2 Fair Value Measurements). The liability with one counterparty was $30.1 million. For its over-the-counter crude oil swap agreements, which are in a liability position, the Company was required to post $24.8 million in hedging collateral deposits at December 31, 2010. This is discussed in Note 1 under Hedging Collateral Deposits.

For its exchange traded futures contracts which are in a liability position, the Company had posted $6.6 million in hedging collateral as of December 31, 2010. 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):

	Three Months Ended December 31,	
	2010	2009
Current Income Taxes		
Federal	$	$ 15,070
State	1,452	3,916
Deferred Income Taxes		
Federal	29,936	17,335
State	6,664	3,757
	38,052	40,078
Deferred Investment Tax Credit	(174)	(174)
Total Income Taxes	$ 37,878	$ 39,904
Presented as Follows:		
Other Income	$ (174)	$ (174)
Income Tax Expense Continuing Operations	38,052	39,883
Income from Discontinued Operations		195
Total Income Taxes	$ 37,878	$ 39,904

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):

	Three Months Ended December 31, 2010	2009
U.S. Income Before Income Taxes	$ 96,421	$ 104,403
Income Tax Expense, Computed at Federal Statutory Rate of 35%	$ 33,747	$ 36,541
Increase (Reduction) in Taxes Resulting from:		
State Income Taxes	5,275	4,987
Miscellaneous	(1,144)	(1,624)
Total Income Taxes	$ 37,878	$ 39,904

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

	At December 31, 2010	At September 30, 2010
Deferred Tax Liabilities:		
Property, Plant and Equipment	$ 915,648	$ 849,869
Pension and Other Post-Retirement Benefit Costs	180,595	177,853
Other	47,690	63,671
Total Deferred Tax Liabilities	1,143,933	1,091,393
Deferred Tax Assets:		
Pension and Other Post-Retirement Benefit Costs	(222,713)	(223,588)
Tax Loss Carryforwards	(45,676)	(9,772)
Other	(75,444)	(81,751)
Total Deferred Tax Assets	(343,833)	(315,111)
Total Net Deferred Income Taxes	$ 800,100	$ 776,282
Presented as Follows:		
Net Deferred Tax Liability/(Asset) Current	$ (20,901)	$ (24,476)
Net Deferred Tax Liability Non-Current	821,001	800,758
Total Net Deferred Income Taxes	$ 800,100	$ 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 December 31, 2010 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 $69.6 million at both December 31, 2010 and September 30, 2010. Also, regulatory assets representing future amounts collectible from customers, corresponding to additional deferred income taxes not previously recorded because of prior ratemaking practices, amounted to $150.9 million and $149.7 million at December 31, 2010 and September 30, 2010, respectively.

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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 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 2007 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 three months ended December 31, 2010, the Company issued 482,109 original issue shares of common stock as a result of stock option exercises and 47,250 original issue shares for restricted stock awards (non-vested as defined by the current accounting literature for stock-based compensation). The Company also issued 3,600 original issue shares of common stock to the non-employee directors of the Company who receive compensation under the Company s Retainer Policy for Non-Employee Directors or the Company s 2009 Non-Employee Director Equity Compensation Plan, as partial consideration for the directors services during the three months ended December 31, 2010. Holders of stock options 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 three months ended December 31, 2010, 269,975 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 December 31, 2010 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 $14.6 million.

At December 31, 2010, 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 $14.6 million discussed above, has been recorded on the Consolidated Balance Sheet at December 31, 2010. The Company expects to recover its environmental clean-up costs through rate recovery.

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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 December 31, 2009
Operating Revenues	$	2,876
Operating Expenses		2,400
Operating Income		476
Other Interest Expense		(7)
Income before Income Taxes		469
Income Tax Expense		195
Income from Discontinued Operations	$	274

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.

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Item 1. Financial Statements (Cont.)

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. There have been no material changes in the amount of assets for any operating segment from the amounts disclosed in the 2010 Form 10-K.

Quarter Ended December 31, 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	$ 242,842	$ 33,513	$ 120,168	$ 53,652	$ 450,175	$ 549	$ 224	$ 450,948
Intersegment Revenues	$ 4,570	$ 19,882	$	$	$ 24,452	$ 1,678	$ (26,130)	$
Segment Profit: Net Income (Loss)	$ 22,990	$ 8,578	$ 27,373	$ 932	$ 59,873	$ (574)	$ (756)	$ 58,543

Quarter Ended December 31, 2009 (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	$ 232,404	$ 34,504	$ 106,351	$ 71,736	$ 444,995	$ 8,929	$ 211	$ 454,135
Intersegment Revenues	$ 4,514	$ 20,257	$	$	$ 24,771	$	$ (24,771)	$
Segment Profit: Income (Loss) from Continuing Operations	$ 23,013	$ 10,354	$ 29,779	$ 1,092	$ 64,238	$ 892	$ (905)	$ 64,225

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Item 1. Financial Statements (Concl.)

Note 9 Retirement Plan and Other Post-Retirement Benefits

Components of Net Periodic Benefit Cost (in thousands):

	Retirement Plan		Other Post-Retirement Benefits	
Three months ended December 31,	2010	2009	2010	2009
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)	(6,584)
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]	(1,793)	(42)	1,921	(100)
Net Periodic Benefit Cost	$ 6,658	$ 5,273	$ 6,826	$ 6,823

[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 three months ended December 31, 2010, the Company contributed $20.6 million to its tax-qualified, noncontributory defined-benefit retirement plan (Retirement Plan) and $6.2 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 at a minimum in the range of $19.0 million to $25.0 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 in the range of $18.0 million to $24.0 million to its VEBA trusts and 401(h) accounts.

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

OVERVIEW

[Please note that this overview is primarily 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 December 31, 2010 compared to the quarter ended December 31, 2009, the Company experienced a decrease in earnings of $6.0 million, primarily due to lower earnings in the Exploration and Production segment, the Pipeline and Storage segment and in the All Other category. For further discussion of the Company s earnings, refer to the Results of Operations section below.

The Company continues to focus on the development of its Marcellus Shale acreage in the Appalachian region of its Exploration and Production segment. 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 quarter ended December 31, 2010, the Company spent $173.0 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.

The Company has engaged Jefferies & Company to explore joint-venture opportunities across its Marcellus Shale acreage in its Exploration and Production segment. It is the Company s goal to accelerate Marcellus Shale development faster than its current plans. By entering into a joint-venture agreement, the Company expects to enhance shareholder value by shifting a significant portion of the early drilling costs to a minority-interest partner while still allowing the Company to continue operating across most of its acreage. The Company s position in the Marcellus Shale provides a competitive advantage for a potential joint-venture partner as a majority of the 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 will forgo any joint-venture opportunities that do not enhance shareholder value when compared to its current growth plans.

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

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

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 $79.6 million in Cash and Temporary Cash Investments at December 31, 2010, 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 and cash from operations 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 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 currently has a moratorium in place that prevents hydraulic fracturing of new horizontal wells in the Marcellus Shale. However, due to the small amount of Marcellus Shale acreage owned by the Company in New York State, the moratorium is 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 this Form 10-Q for the quarter ended December 31, 2010 for further discussion.

The Company is pursuing the sale of 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. With this strategy in mind, the Company entered into a purchase and sale agreement in December 2010 whereby it intends to sell its 50% equity method investments in Seneca Energy and Model City. It is estimated that the Company will record a gain of approximately $28.0 million from this sale. The sale is expected to close during the quarter ended March 31, 2011.

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. There have been no material changes to that disclosure other than as set forth below. The information presented below updates and should be read in conjunction with the critical accounting estimates in that Form 10-K.

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

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 December 31, 2010, the ceiling exceeded the book value of the oil and gas properties by approximately $232 million. The 12-month average of the first day of the month price for crude oil for each month during the twelve months ended December 31, 2010, based on posted Midway Sunset prices was $72.25 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 December 31, 2010, based on the quoted Henry Hub spot price for natural gas, was $4.38 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 December 31, 2010.) If natural gas prices used in the ceiling test calculation at December 31, 2010 had been $1 per MMBtu lower, the ceiling would have exceeded the book value of the Company s oil and gas properties by approximately $56 million. If crude oil prices used in the ceiling test calculation at December 31, 2010 had been $5 per Bbl lower, the ceiling would have exceeded the book value of the Company s oil and gas properties by approximately $125 million. If both natural gas and crude oil prices used in the ceiling test calculation at December 31, 2010 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 $8 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.

RESULTS OF OPERATIONS

Earnings

The Company s earnings were $58.5 million for the quarter ended December 31, 2010 compared to earnings of $64.5 million for the quarter ended December 31, 2009. 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. The Company s earnings from continuing operations were $58.5 million for the quarter ended December 31, 2010 compared with $64.2 million for the quarter ended December 31, 2009. The decrease in earnings from continuing operations of $5.7 million is primarily a result of lower earnings in the Exploration and Production segment, the Pipeline and Storage segment and the All Other category.

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.

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

Three Months Ended December 31 *(Thousands)*	2010	2009	Increase (Decrease)
Utility	$ 22,990	$ 23,013	$ (23)
Pipeline and Storage	8,578	10,354	(1,776)
Exploration and Production	27,373	29,779	(2,406)
Energy Marketing	932	1,092	(160)
Total Reportable Segments	59,873	64,238	(4,365)
All Other	(574)	892	(1,466)
Corporate	(756)	(905)	149
Total Earnings from Continuing Operations	58,543	64,225	(5,682)
Earnings from Discontinued Operations		274	(274)
Total Consolidated	$ 58,543	$ 64,499	$ (5,956)

Utility
Utility Operating Revenues

Three Months Ended December 31 *(Thousands)*	2010	2009	Increase (Decrease)
Retail Sales Revenues:			
Residential	$ 177,189	$ 176,597	$ 592
Commercial	22,545	24,406	(1,861)
Industrial	1,244	1,288	(44)
	200,978	202,291	(1,313)
Transportation	35,412	30,695	4,717
Off-System Sales	8,889	1,691	7,198
Other	2,133	2,241	(108)
	$ 247,412	$ 236,918	$ 10,494

Utility Throughput

Three Months Ended December 31 *(MMcf)*	2010	2009	Increase (Decrease)
Retail Sales:			
Residential	17,160	16,824	336
Commercial	2,469	2,490	(21)
Industrial	146	158	(12)
	19,775	19,472	303
Transportation	18,110	17,061	1,049

Off-System Sales	1,863	356	1,507
	39,748	36,889	2,859

Degree Days

Three Months Ended				Percent Colder (Warmer) Than	
December 31	Normal	2010	2009	Normal[(1)]	Prior Year[(1)]
Buffalo	2,260	2,332	2,246	3.2	3.8
Erie	2,081	2,160	2,048	3.8	5.5

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

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

2010 Compared with 2009

Operating revenues for the Utility segment increased $10.5 million for the quarter ended December 31, 2010 as compared with the quarter ended December 31, 2009. This increase largely resulted from a $7.2 million increase in off-system sales revenues and a $4.7 million increase in transportation revenues, slightly offset by a $1.3 million decrease in retail gas sales revenues. The decrease in retail gas sales revenues of $1.3 million was largely a function of the recovery of lower gas costs (subject to certain timing variations, gas costs are recovered dollar for dollar in revenues), slightly offset by colder weather. The recovery of lower gas costs resulted from a lower cost of purchased gas. The Utility segment s average cost of purchased gas, including the cost of transportation and storage, was $6.06 per Mcf for the three months ended December 31, 2010, a decrease of 14% from the average cost of $7.08 per Mcf for the three months ended December 31, 2009.

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 increase in transportation revenues of $4.7 million was primarily due to a 1.0 Bcf increase in transportation throughput, largely the result of colder weather.

The Utility segment s earnings for each of the quarters ended December 31, 2010 and December 31, 2009 were $23.0 million. In the New York jurisdiction, earnings decreased $1.1 million. An increase in interest expense on gas costs ($0.3 million), a decrease in interest income on gas costs ($0.2 million), lower revenues as a result of routine regulatory adjustments ($0.2 million), an increase in depreciation expense ($0.2 million), and an increase in other taxes ($0.2 million) were the main factors in this earnings decrease. In the Pennsylvania jurisdiction, earnings increased $1.1 million. The positive earnings impact of colder weather ($0.5 million) and higher usage per account ($0.5 million), coupled with a decrease in interest expense on gas costs ($0.3 million) were the main factors in the earnings increase. This was slightly offset by an increase in operating expenses ($0.1 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 December 31, 2010, the WNC reduced earnings by $0.1 million, as it was colder than normal. For the quarter ended December 31, 2009, the WNC preserved $0.2 million of earnings, as it was warmer than normal.

Pipeline and Storage

Pipeline and Storage Operating Revenues

Three Months Ended December 31 *(Thousands)*	2010	2009	Increase (Decrease)
Firm Transportation	$ 34,950	$ 36,428	$ (1,478)
Interruptible Transportation	314	305	9
	35,264	36,733	(1,469)
Firm Storage Service	16,603	16,623	(20)
Interruptible Storage Service	17	56	(39)
Other	1,511	1,349	162
	$ 53,395	$ 54,761	$ (1,366)

Pipeline and Storage Throughput

Three Months Ended December 31 *(MMcf)*	2010	2009	Increase (Decrease)

Firm Transportation	89,249	80,639	8,610
Interruptible Transportation	125	755	(630)
	89,374	81,394	7,980

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

2010 Compared with 2009

Operating revenues for the Pipeline and Storage segment decreased $1.4 million in the quarter ended December 31, 2010 as compared with the quarter ended December 31, 2009. The decrease was primarily due to a decrease in firm transportation revenues of $1.5 million. This decrease 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. Shippers are seeking alternative lower priced gas supply (and in some cases, not renewing 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 proposed 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. 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. While transportation volume increased by 8.0 Bcf largely due to colder weather, there was little impact on revenues due to Supply Corporation and Empire s straight fixed-variable rate design.

The Pipeline and Storage segment s earnings for the quarter ended December 31, 2010 were $8.6 million, a decrease of $1.8 million when compared with earnings of $10.4 million for the quarter ended December 31, 2009. The earnings decrease was due to the earnings impact of lower transportation revenues of $0.9 million, as discussed above, combined with higher operating expenses ($1.0 million). The increase in operating expenses can primarily be attributed to higher pension expense and higher personnel costs.

Exploration and Production

Exploration and Production Operating Revenues

Three Months Ended December 31 *(Thousands)*	2010	2009	Increase (Decrease)
Gas (after Hedging)	$ 58,009	$ 40,868	$ 17,141
Oil (after Hedging)	58,692	62,695	(4,003)
Gas Processing Plant	6,683	7,208	(525)
Other	(114)	47	(161)
Intrasegment Elimination [(1)]	(3,102)	(4,467)	1,365
	$ 120,168	$ 106,351	$ 13,817

(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 December 31	2010	2009	Increase (Decrease)
Gas Production *(MMcf)*			
Gulf Coast	2,013	2,690	(677)
West Coast	935	997	(62)
Appalachia	8,082	2,801	5,281

Total Production	11,030	6,488	4,542
Oil Production *(Mbbl)*			
Gulf Coast	106	146	(40)
West Coast	654	684	(30)
Appalachia	10	11	(1)
Total Production	770	841	(71)

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

Three Months Ended December 31	2010	2009	Increase (Decrease)
Average Gas Price/Mcf			
Gulf Coast	$ 4.55	$ 4.84	$ (0.29)
West Coast	$ 3.92	$ 4.64	$ (0.72)
Appalachia	$ 4.03	$ 5.07	$ (1.04)
Weighted Average	$ 4.11	$ 4.91	$ (0.80)
Weighted Average After Hedging	$ 5.26	$ 6.30	$ (1.04)
Average Oil Price/Bbl			
Gulf Coast	$ 83.97	$ 72.78	$ 11.19
West Coast	$ 80.45	$ 70.32	$ 10.13
Appalachia	$ 81.40	$ 84.05	$ (2.65)
Weighted Average	$ 80.95	$ 70.94	$ 10.01
Weighted Average After Hedging	$ 76.24	$ 74.53	$ 1.71

2010 Compared with 2009

Operating revenues for the Exploration and Production segment increased $13.8 million for the quarter ended December 31, 2010 as compared with the quarter ended December 31, 2009. Gas production revenue after hedging increased $17.1 million primarily due to production increases in the Appalachian division. The increase in Appalachian natural gas production was mainly due to additional wells within the Marcellus Shale formation, primarily in Tioga County, Pennsylvania, coming on line in the later part of fiscal 2010 and the quarter ended December 31, 2010. The increase in natural gas production of 4.5 Bcf was partially offset by a $1.04 per Mcf decrease in the weighted average price of natural gas after hedging. Oil production revenue after hedging decreased $4.0 million due to lower crude oil production levels, which were partially offset by a slight increase in the weighted average price of crude oil after hedging ($1.71 per Bbl). In addition, there was a $0.8 million increase in processing plant revenues (net of eliminations) primarily because of the lower cost of West Coast gas production, quarter over quarter.

The Exploration and Production segment s earnings for the quarter ended December 31, 2010 were $27.4 million, a decrease of $2.4 million when compared to earnings of $29.8 million for the quarter ended December 31, 2009. The decrease in earnings is primarily attributable to lower natural gas prices ($7.5 million), higher depletion expense ($6.3 million), lower crude oil production ($3.5 million), higher lease operating expenses ($3.3 million), higher general, administrative and other operating expenses ($1.7 million), the earnings impact associated with higher income tax expense ($0.8 million), and higher property taxes ($0.3 million). The decrease in earnings was partially offset by higher natural gas production ($18.6 million), lower interest expense ($1.1 million), higher crude oil prices ($0.9 million), and higher net processing plant revenues ($0.5 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 the Appalachian region. Higher personnel costs are largely responsible for the increase in general, administrative and other operating expenses. The increase in income taxes is attributable to the loss of a domestic production activities deduction that occurred during the quarter ended September 30, 2010 and its impact on income tax expense for the quarter ended December 31, 2010 coupled with higher state income taxes. Higher property taxes are attributable to a revision of the California property tax liability. A decrease in the average amount of debt outstanding and the capitalization of interest is largely responsible for the decrease in interest expense.

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

Energy Marketing

Energy Marketing Operating Revenues

Three Months Ended December 31 *(Thousands)*	2010	2009	Decrease
Natural Gas (after Hedging)	$ 53,639	$ 71,713	$ (18,074)
Other	13	23	(10)
	$ 53,652	$ 71,736	$ (18,084)

Energy Marketing Volume

Three Months Ended December 31	2010	2009	Decrease
Natural Gas (MMcf)	10,746	14,101	(3,355)

2010 Compared with 2009

Operating revenues for the Energy Marketing segment decreased $18.1 million for the quarter ended December 31, 2010 as compared with the quarter ended December 31, 2009. The decrease is largely attributable to lower gas sales revenue, due primarily to a decrease in volume sold as well as a slightly lower average price of natural gas that was recovered through revenues. The decrease in volume is largely attributable to a decrease in volume sold to low-margin wholesale customers as well as 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. Such transactions had the effect of increasing revenue and volume sold with minimal impact to earnings.

The Energy Marketing segment s earnings for the quarter ended December 31, 2010 were $0.9 million, a decrease of $0.2 million when compared with earnings of $1.1 million for the quarter ended December 31, 2009. This decrease was largely a result of an increase in operating expenses of $0.1 million primarily due to higher pension expense and higher personnel costs, offset slightly by lower bad debt expense.

Corporate and All Other

2010 Compared with 2009

Corporate and All Other operations recorded a loss from continuing operations of $1.3 million for the quarter ended December 31, 2010, a decrease of $1.3 million from the loss of less than $0.1 million for the quarter ended December 31, 2009. The decrease in earnings was largely due to lower timber margins of $2.9 million, lower interest income of $1.0 million, and higher operating expenses of $0.4 million. Additionally, the Company recorded a $0.7 million loss from unconsolidated subsidiaries during the quarter ended December 31, 2010 compared to income of $0.3 million during the quarter ended December 31, 2009. The decrease in timber margins is attributable to the sale of the Company s sawmill in Marienville, Pennsylvania, the mill s inventory, stumpage tracts, and other land and timber acreage in September 2010. Because of the sale, the Company did not have any margins from log and lumber sales during the quarter ended December 31, 2010. During the quarter ended December 31, 2009, the Company had $2.9 million of margins related to log and lumber sales. The decrease in interest income was due to lower interest collected from the Company s Exploration and Production segment as a result of the repayment of $200 million of 7.5% notes that matured in November 2010. The loss from unconsolidated subsidiaries resulted from lower renewable energy credit revenue recorded by Seneca Energy and Model City. The decrease in earnings was partially offset by higher revenues ($1.2 million) related to Midstream Corporation s gathering and processing operations due largely to a significant increase in Midstream Corporation s operating activities. In addition, lower depreciation and depletion expense of $1.1 million (mostly attributable to decreased depletion expense due to a decrease in timber

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harvested due to the aforementioned sale of the Company s timber harvesting and milling operations) and lower interest expense of $1.1 million (primarily the result of lower borrowings at a lower interest rate due to the aforementioned November 2010 debt repayment) partially offset the overall decrease in earnings.

Interest Income

Interest income was $0.3 million lower in the quarter ended December 31, 2010 as compared to the quarter ended December 31, 2009. Lower cash investment balances and slightly lower interest rates on such investments were the primary factors contributing to the decrease.

Other Income

Other income increased $0.6 million for the quarter ended December 31, 2010 as compared with the quarter ended December 31, 2009. The increase is attributed to a $0.4 million gain on the sale of Horizon Energy Development. In addition, there was a $0.2 million increase in allowance for funds used during construction in the Pipeline and Storage segment.

Interest Expense on Long-Term Debt

Interest on long-term debt decreased $1.9 million for the quarter ended December 31, 2010 as compared with the quarter ended December 31, 2009. This decrease is primarily the result of a lower average amount of long-term debt outstanding combined with slightly lower average interest rates. The Company repaid $200 million of 7.5% notes that matured in November 2010.

CAPITAL RESOURCES AND LIQUIDITY

The Company s primary source of cash during the three-month periods ended December 31, 2010 and December 31, 2009 consisted of cash provided by operating activities. This source of cash was supplemented by short-term borrowings (for the quarter ended December 31, 2010) and by issues of new shares of common stock as a result of stock option exercises (for the quarter ended December 31, 2009). During the three months ended December 31, 2010 and December 31, 2009, 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.

Operating Cash Flow

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

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

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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. The Company uses various derivative financial instruments, including price swap agreements and futures contracts in an attempt to manage this energy commodity price risk.

Net cash provided by operating activities totaled $87.5 million for the three months ended December 31, 2010, an increase of $19.2 million when compared with the $68.3 million provided by operating activities for the three months ended December 31, 2009. 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 December 31, 2010 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 $200.9 million for the three months ended December 31, 2010 and $67.7 million for the three months ended December 31, 2009. The table below presents these expenditures:

Total Expenditures for Long-Lived Assets

Three Months Ended December 31, (Millions)	2010	2009	Increase (Decrease)
Utility:			
Capital Expenditures	$ 10.9	$ 12.0	$ (1.1)
Pipeline and Storage:			
Capital Expenditures	9.2(1)	7.0	2.2
Exploration and Production:			
Capital Expenditures	178.1(1)(2)	47.7(3)(4)	130.4
Investment in Subsidiary	1.7		1.7
All Other:			
Capital Expenditures	1.0	1.0(4)	
Total Expenditures from Continuing Operations	$ 200.9	$ 67.7	$ 133.2

(1) Capital expenditures for the Exploration and Production segment include $60.7 million of accrued capital expenditures at December 31, 2010, the majority of which was in the Appalachian region. In addition, capital expenditures for the Pipeline and Storage segment include $2.0 million of accrued capital expenditures at December 31, 2010. These amounts were excluded from the Consolidated Statement of Cash Flows at December 31, 2010 since they represented non-cash investing activities at that date.

(2) Amount for the three months ended December 31, 2010 excludes $55.5 million of accrued capital expenditures in the Exploration and Production segment, the majority of which was in the Appalachian region. This amount was accrued at September 30, 2010 and paid during the three months ended December 31, 2010. 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. The amount has been included in the Consolidated Statement of Cash Flows at December 31, 2010.

(3)

Amount includes $15.4 million of accrued capital expenditures at December 31, 2009, the majority of which was in the Appalachian region. This amount was excluded from the Consolidated Statement of Cash Flows at December 31, 2009 since it represented a non-cash investing activity at that date.

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(4) Capital expenditures for the Exploration and Production segment for the three months ended December 31, 2009 exclude $9.1 million of capital expenditures, the majority of which was in the Appalachian region. Capital expenditures for All Other for the three months ended December 31, 2009 exclude $0.7 million of 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 three months ended December 31, 2009. 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 December 31, 2009.

Utility

The majority of the Utility capital expenditures for the three months ended December 31, 2010 and December 31, 2009 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 three months ended December 31, 2010 and December 31, 2009 were related to additions, improvements, and replacements to this segment s transmission and gas storage systems.

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, amounts remain in Deferred Charges until construction begins, at which 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 December 31, 2010, the total amount reserved for the Pipeline and Storage segment s preliminary survey and investigation costs was $5.6 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 will enter into a 20-year firm transportation agreement for 320,000 Dth/day. This capacity will provide the subscribing shipper 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 late 2012, and Supply Corporation has begun working on an application for FERC authorization of the project, which it expects to file in the second quarter of fiscal year 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 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 December 31, 2010, less than $0.1 million has been spent to study the Northern Access expansion project, which has been included in preliminary survey and investigation charges and has been fully reserved for at December 31, 2010.

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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. Two precedent agreements totaling 160,000 Dth/day of firm transportation have been executed. The project will allow Marcellus production located in the vicinity of Line N to flow south into Texas Eastern and access markets off Texas Eastern s system, with a projected in-service date of September 2011. 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. A service agreement for 150,000 Dth/day of firm transportation has been executed, and a service agreement for the other 10,000 Dth/day of firm transportation has been executed by the shipper to become effective upon the shipper s posting of the necessary letter of credit. The preliminary cost estimate for the Line N Expansion Project is $23 million. As of December 31, 2010, $2.4 million has been spent to study the Line N expansion project. The Company has determined that it is highly probable that this project will be built. Accordingly, all previous reserves have been reversed and $1.7 million has been reestablished as a Deferred Charge on the Consolidated Balance Sheet. The remainder spent on the project of $0.7 million represents progress payments on a compressor. The Company expects to begin construction in the second quarter of fiscal 2011.

Supply Corporation has also executed a precedent agreement for 150,000 Dth/day of additional capacity on Line N to TETCO Holbrook to be ready for service beginning November 2012 (Line N Phase II Expansion Project). The Line N Phase II Expansion Project will provide approximately 195,000 Dth/day of incremental firm transportation capacity. Marketing efforts are underway for the remaining 45,000 Dth/day of capacity. The preliminary cost estimate for the Line N Phase II Expansion Project is approximately $40 million. As of December 31, 2010, less than $0.1 million has been spent to study the Line N Phase II Expansion Project, which has been included in preliminary survey and investigation charges and has been fully reserved for at December 31, 2010.

Following up on Supply Corporation s Lamont Project that went into service on June 15, 2010, a second Lamont project is planned (Lamont Phase II Project). With the construction of an additional 3,400 horsepower, 50,000 Dth/day of incremental firm capacity will be available starting July 1, 2011 ramping up to full service by October 1, 2011. Supply Corporation has two executed binding service agreements for the full capacity of this project. The preliminary cost estimate for the Lamont Phase II Project is approximately $7 million. As of December 31, 2010, approximately $1.8 million has been spent to study the Lamont Phase II project, of which less than $0.1 million represents preliminary survey and investigation charges that have been fully reserved for at December 31, 2010. The remainder represents progress payments on a compressor.

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 2013.

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 $260 million. As of December 31, 2010, approximately $4.1 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 December 31, 2010.

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Supply Corporation expects that its previously announced Appalachian Lateral project will complement the W2E Overbeck to Leidy project due to its strategic upstream location. The Appalachian Lateral project, which would be routed through several counties in central Pennsylvania where producers are actively drilling and seeking market access for their newly discovered reserves, will be able to collect and transport locally produced Marcellus shale gas into the W2E Overbeck to Leidy facilities. Supply Corporation expects to continue marketing efforts for the Appalachian Lateral and all other remaining sections of W2E. The timeline and projected costs associated with W2E sections other than W2E Overbeck to Leidy, including the Appalachian Lateral project, will depend on market development, and as of December 31, 2010, no preliminary survey and investigation charges had been spent on those projects.

Empire has executed precedent 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 recently completed Empire Connector line, in Tioga County, Pennsylvania. Empire s preliminary cost estimate for the Tioga County Extension Project is approximately $46 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 January 28, 2010, the FERC granted Empire s request for a pre-filing environmental review of the Tioga County Extension Project, and on August 26, 2010, Empire filed an NGA Section 7(c) application to the FERC for approval of the project. Empire anticipates that these facilities will be placed in service on September 1, 2011. As of December 31, 2010, approximately $2.3 million has been spent to study the Tioga County Extension Project. The Company has determined that it is highly probable that this project will be built. Accordingly, all previous reserves have been reversed and the $2.3 million has been reestablished as a Deferred Charge on the Consolidated Balance Sheet.

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 (Tioga County Extension Phase II). 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 Tioga County Extension Phase II project may involve up to 30,000 horsepower of compression at two new stations and a 25 mile 24 pipeline extension, at a preliminary cost estimate of up to $135 million. As of December 31, 2010, less than $0.1 million has been spent to study the Tioga County Extension Phase II project, which has been included in preliminary survey and investigation charges and has been fully reserved for at December 31, 2010. No decision has been made to proceed with this project.

The Company anticipates financing the Line N Expansion Projects, the Lamont Project, the Northern Access expansion project, the W2E Overbeck to Leidy project, the Appalachian Lateral 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 $79.6 million in Cash and Temporary Cash Investments at December 31, 2010, 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.

Exploration and Production

The Exploration and Production segment capital expenditures for the three months ended December 31, 2010 were primarily well drilling and completion expenditures and included approximately $174.3 million for the Appalachian region (including $173.0 million in the Marcellus Shale area), $2.7 million for the West Coast region and $1.1 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 $57.0 million spent to develop proved undeveloped reserves. The capital expenditures in the Appalachian

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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.

In addition, during the quarter ended December 31, 2010, the Company paid $1.7 million of additional purchase price to Ivanhoe Energy related to the Company s July 2009 acquisition of Ivanhoe Energy s United States oil and gas operations.

The Exploration and Production segment capital expenditures for the three months ended December 31, 2009 were primarily well drilling and completion expenditures and included approximately $39.0 million for the Appalachian region, $7.4 million for the West Coast region and $1.3 million for the Gulf Coast region. These amounts included approximately $12.8 million spent to develop proved undeveloped reserves.

For all of fiscal 2011, the Company expects to spend $531.0 million on Exploration and Production segment capital expenditures. Previously reported 2011 estimated capital expenditures for the Exploration and Production segment were $455.0 million. In the Appalachian region, estimated capital expenditures will increase from $405.0 million to $490.0 million. Estimated capital expenditures in the Gulf Coast region will decrease from $11.0 million to $2.0 million, substantially all of which is for the off-shore program in the shallow waters of the Gulf of Mexico. Estimated capital expenditures in the West Coast region will remain at the previously reported $39.0 million. The Company s estimate of drilling 100 to 130 gross wells in the Marcellus Shale during 2011 remains unchanged. The decline in the Gulf Coast estimated capital expenditures is due to the Company s decreased emphasis in the Gulf Coast region. The increase in estimated capital expenditures in the Appalachian region is partially due to the Company s $24.1 million acquisition of oil and gas properties noted above. The remainder of the increase in estimated capital expenditures in the Appalachian region is due to additional capital spending anticipated as a result of this acquisition. The Company expects to use cash from operations as the first means of financing its future capital expenditures during 2011, with short-term debt providing temporary financing when needed. Natural gas and crude oil prices combined with production from existing wells will be a significant factor in determining how much of the capital expenditures are funded with cash from operations. The Company may issue some long-term debt in conjunction with these expenditures in the later part of fiscal 2011 or in fiscal 2012.

All Other

The majority of the All Other category s capital expenditures for long-lived assets for the three months ended December 31, 2010 were primarily for additions and improvements to Midstream Corporation s gathering system in Tioga County, Pennsylvania as well as for the construction of Midstream Corporation s Trout Run Gathering System, as discussed below. For the three months ended December 31, 2009, the majority of the All Other category s capital expenditures for long lived assets were for the construction of Midstream Corporation s gathering system in Tioga County, Pennsylvania.

NFG Midstream Trout Run, LLC, a wholly owned subsidiary of Midstream Corporation, is planning a gathering system in Lycoming County, Pennsylvania. The project, called the Trout Run Gathering System, is anticipated to be placed in service in the fall of 2011. The system will consist of approximately 15.5 miles of gathering system at a cost of $27 million. As of December 31, 2010, the Company has spent approximately $0.2 million in costs related to this project.

The Company anticipates funding the Midstream Corporation Trout Run Gathering System project with cash from operations and/or short-term borrowings. Given the Company s cash position at December 31, 2010, 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

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

Financing Cash Flow

Consolidated short-term debt increased $20.5 million during the three months ended December 31, 2010 and did not exceed $20.5 million outstanding during the quarter. 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. At December 31, 2010, the Company had outstanding short-term notes payable to banks of $20.5 million and no outstanding commercial paper.

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 $405.0 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 December 31, 2010, the Company s debt to capitalization ratio (as calculated under the facility) was .38. The constraints specified in the committed credit facility would permit an additional $2.18 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 December 31, 2010, the Company would have been permitted to issue up to a maximum of $1.55 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 December 31, 2010) was issued, contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement, or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

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The Company s $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 December 31, 2010, the Company had no debt outstanding under the committed credit facility.

The Company s embedded cost of long-term debt was 6.85% at December 31, 2010 and 6.95% at December 31, 2009. If the Company were to issue 10-year long-term debt today, its borrowing costs might be expected to be in the range of 5.50% to 5.75%.

Current Portion of Long-Term Debt at December 31, 2010 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 $26.3 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 three months ended December 31, 2010, the Company contributed $20.6 million to its Retirement Plan and $6.2 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 at a minimum in the range of $19.0 million to $25.0 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 in the range of $18.0 million to $24.0 million to its VEBA trusts and 401(h) accounts.

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Market Risk Sensitive Instruments

On July 21, 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (H.R. 4173) was signed into law. The law includes provisions related to the swaps and over-the-counter derivatives markets. A variety of rules must be adopted by federal agencies (including the Commodity Futures Trading Commission, SEC and the FERC) to implement the law. These rules, which will be implemented over time frames as determined in the law, could have a significant impact on the Company. For example, while the Company expects to be exempt from the law s mandatory clearing and exchange trading requirements for most or all of its commodity hedges, other requirements with respect to these hedges, including capital, margin and reporting requirements, may apply to the Company. These requirements will be determined as regulators write detailed rules. The Company is currently reviewing the provisions of H.R. 4173 and proposed rules, but it will not be able to determine the impact to its financial condition until the final rules are issued.

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 $37.4 million at December 31, 2010 and represent 32.2% of the Total Net Assets shown in Part I, Item 1 at Note 2 Fair Value Measurements at December 31, 2010.

The increase in the net fair value liability of the Level 3 positions from October 1, 2010 to December 31, 2010, 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 December 31, 2010.

The fair value of all of the Company s Net Derivative Assets was reduced by $0.5 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.

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.

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

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 that portions of the rate order were invalid because they failed to meet the applicable legal standard for agency decisions. Among the issues challenged by the Company was the reasonableness of the NYPSC s disallowance of expense items and the methodology used for calculating rate of return, which the appeal contended understated the Company s cost of equity. Because of the issues appealed, the case was later transferred to the Appellate Division, New York State s second-highest court. On December 31, 2009, the Appellate Division issued its Opinion and Judgment. The court upheld the NYPSC s determination relating to the authorized rate of return but also supported the Company s argument that the NYPSC improperly disallowed recovery of certain environmental clean-up costs. On February 1, 2010, the NYPSC filed a motion with the Court of Appeals, New York State s highest court, seeking permission to appeal the Appellate Division s annulment of that part of the rate order relating to disallowance of environmental clean up costs. On May 4, 2010, the NYPSC s motion was granted, and the matter is scheduled to be heard by the Court of Appeals. The Company cannot predict the outcome of the appeal proceedings at this time.

Pennsylvania Jurisdiction

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

Pipeline and Storage

Supply Corporation currently does not have a rate case on file with the FERC. 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, in conjunction with which Empire will either justify Empire s existing recourse rates or propose alternative rates.

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.

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

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 $14.6 million.

At December 31, 2010, 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 $14.6 million discussed above, has been recorded on the Consolidated Balance Sheet at December 31, 2010. 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 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 June 2009, the FASB issued amended authoritative guidance to improve and clarify financial reporting requirements by companies involved with variable interest entities. The new guidance requires a company to perform an analysis to determine whether the company s variable interest or interests give it a controlling financial interest in a variable interest entity. The analysis also assists in identifying the primary beneficiary of a variable interest entity. This authoritative guidance became effective for the quarter ended December 31, 2010. Given the current organizational structure of the Company, the Company s consolidated financial statements were not impacted by this guidance.

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

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

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-look 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, hurricanes, other severe weather, pest infestation or other 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;

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;

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

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;

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

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

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 December 31, 2010.

Changes in Internal Control Over Financial Reporting

On October 1, 2010, the Company replaced The Northern Trust Company with JPMorgan Chase Bank, NA as trustee and custodian of assets held in trust for the beneficiaries of the Company s qualified defined-benefit retirement plan and other post-retirement benefit plans. The change in trustee was a result of an appraisal by the Company s Retirement Committee of outsourced trust and custodial services and was not the result of any actual or perceived deficiencies in internal controls at the previous trustee. The impact of the change, including the transfer of trust assets on October 1, 2010, has been evaluated by management and adequately incorporated into management s ongoing monitoring of internal controls over financial reporting.

On November 1, 2010, Seneca implemented Quorum Business Solutions software as its Enterprise Resource Planning Accounting System and Land/Geographical Information System to help support the growth of the Exploration and Production segment. These system changes were a result of an evaluation of the previous accounting and land systems and related processes to support evolving needs and were not the result of any actual or perceived deficiencies in the previous systems. These implementations resulted in certain changes to Seneca s processes and internal controls impacting financial reporting. While there are inherent risks involved with the implementation of any new system, management believes that it is adequately monitoring and managing the transition.

There were no changes in the Company s internal control over financial reporting that occurred during the quarter ended December 31, 2010, other than the changes that occurred on October 1, 2010 and November 1, 2010, that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

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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 have not materially changed other than as set forth below. The risk factors presented below supersede the risk factors having the same captions in the 2010 Form 10-K and should otherwise be read in conjunction with all of the risk factors disclosed in the 2010 Form 10-K.

The Company s need to comply with comprehensive, complex, and sometimes unpredictable government regulations may increase its costs and limit its revenue growth, which may result in reduced earnings.

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

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

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

Both the NYPSC and the PaPUC have instituted proceedings for the purpose of promoting conservation of energy commodities, including natural gas. In New York, Distribution Corporation implemented a Conservation Incentive Program that promotes conservation and efficient use of natural gas by offering customer rebates for high-efficiency appliances, among other things. The intent of conservation and efficiency programs is to reduce customer usage of natural gas. Under traditional

Item 1A. Risk Factors (Cont.)

volumetric rates, reduced usage by customers results in decreased revenues to the Utility. To prevent revenue erosion caused by conservation, the NYPSC approved a revenue decoupling mechanism that renders Distribution Corporation s New York division financially indifferent to the effects of conservation. In Pennsylvania, although a generic statewide proceeding is pending, the PaPUC has not yet directed Distribution Corporation to implement conservation measures. If the NYPSC were to revoke the revenue decoupling mechanism in a future proceeding or the PaPUC were to adopt a conservation program without a revenue decoupling mechanism or other changes in rate design, reduced customer usage could decrease revenues, forcing Distribution Corporation to file for rate relief.

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

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

In the wake of certain pipeline accidents not involving the Company, new laws or regulations may be adopted regarding pipeline safety. Proposals have been made at the federal level with respect to matters such as reporting of pipeline accidents, increased fines for pipeline safety violations, the designation of additional high consequence areas along pipelines, minimum requirements for leak detection systems, installation of emergency flow restricting devices, and revision of valve spacing requirements. In addition, unrelated to these safety initiatives, the EPA in April 2010 issued an Advance Notice of Proposed Rulemaking reassessing its regulations governing the use and distribution in commerce of PCBs. The EPA is considering, among other things, a proposal to eliminate by 2020 the PCB use authorization for natural gas pipeline systems, and a proposal to eliminate the authorization for storage of PCB-containing equipment for reuse. The EPA projects that it may issue a Notice of Proposed Rulemaking in March 2012. If as a result of new laws or regulations the Company incurs material costs that it is unable to recover fully through rates or otherwise offset, the Company s financial condition, results of operations, and cash flows would be adversely affected.

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

Operations in the Company s Exploration and Production segment are materially dependent on prices received for its oil and natural gas production. Both short-term and long-term price trends affect the economics of exploring for, developing, producing, gathering and processing oil and natural gas. Oil and natural gas prices can be volatile and can be affected by: weather conditions, including natural disasters; the supply and price of foreign oil and natural gas; the level of consumer product demand; national and worldwide economic conditions, including economic disruptions caused by terrorist activities, acts of war

Item 1A. Risk Factors (Cont.)

or major accidents; political conditions in foreign countries; the price and availability of alternative fuels; the proximity to, and availability of capacity on transportation facilities; regional levels of supply and demand; energy conservation measures; and government regulations, such as regulation of greenhouse gas emissions and natural gas transportation, royalties, and price controls. The Company sells most of the oil and natural gas that it produces at current market prices rather than through fixed-price contracts, although as discussed below, the Company frequently hedges the price of a significant portion of its future production in the financial markets. The prices the Company receives depend upon factors beyond the Company s control, including the factors affecting price mentioned above. The Company believes that any prolonged reduction in oil and natural gas prices could restrict its ability to continue the level of exploration and production activity the Company otherwise would pursue, which could have a material adverse effect on its revenues, cash flows and results of operations.

In the Company s Pipeline and Storage segment, significant changes in the price differential between equivalent quantities of natural gas at different geographic locations could adversely impact the Company. For example, if the price of natural gas at a particular receipt point on the Company s pipeline system increases relative to the price of natural gas at other locations, then the volume of natural gas received by the Company at the relatively more expensive receipt point may decrease, or the price the Company charges to transport that natural gas may decrease. Supply Corporation and Empire have experienced such a change at the Canada/United States border at the Niagara River, where gas prices have increased relative to prices available at Leidy, Pennsylvania. This change in price differential has caused shippers to seek alternative lower priced gas supplies and, consequently, alternative transportation routes. Supply Corporation and Empire have seen transportation volumes decrease as a result of this situation, and in some cases, shippers have decided not to renew transportation contracts. While much of the impact of lower volumes under existing contracts is offset by the straight fixed-variable rate design utilized by Supply Corporation and Empire, this rate design does not protect Supply Corporation or Empire where shippers do not contract for expiring capacity at the same quantity and rate. As contract renewals have decreased, revenues and earnings in the Pipeline and Storage segment have decreased. Additional declines in this contracted transportation capacity could further adversely affect revenues, cash flows and results of operations. Supply Corporation and Empire are responding to this changed gas price environment by developing projects designed to reverse the flow on their existing systems as described elsewhere in this report.

Significant changes in the price differential between futures contracts for natural gas having different delivery dates could also adversely impact the Company. For example, if the prices of natural gas futures contracts for winter deliveries to locations served by the Pipeline and Storage segment decline relative to the prices of such contracts for summer deliveries (as a result, for instance, of increased production of natural gas within the Pipeline and Storage segment s geographic area or other factors), then demand for the Company s natural gas storage services driven by that price differential could decrease. Such changes in price differential could also affect the Energy Marketing segment s ability to offset its natural gas storage costs through hedging transactions. These changes could adversely affect revenues, cash flows and results of operations.

Environmental regulation significantly affects the Company s business.

The Company s business operations are subject to federal, state, and local laws and regulations relating to environmental protection. These laws and regulations concern the generation, storage, transportation, disposal or discharge of contaminants and greenhouse gases into the environment, the reporting of such matters, and the general protection of public health, natural resources, wildlife and the environment. Costs of compliance and liabilities could negatively affect the Company s results of operations, financial condition and cash flows. In addition, compliance with environmental laws and regulations could require unexpected capital expenditures at the Company s facilities or delay or cause the cancellation of expansion projects or oil and natural gas drilling activities. Because the costs of complying with environmental regulations are significant, additional regulation could negatively affect the Company s business. Although the Company cannot predict the impact of the interpretation or enforcement of EPA standards or other federal, state and local laws or regulations, the Company s costs could increase if environmental laws and regulations change.

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Item 1A. Risk Factors (Concl.)

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 addition, the U.S. Congress has from time to time considered bills that would establish a cap-and-trade program to reduce emissions of greenhouse gases. Legislation or regulation that restricts greenhouse gas emissions could increase the Company s cost of environmental compliance by requiring the Company to install new equipment to reduce emissions from larger facilities and/or purchase emission allowances. International, federal, state or regional climate change and greenhouse gas initiatives could also delay or otherwise negatively affect efforts to obtain permits and other regulatory approvals with regard to existing and new facilities, or impose additional monitoring and reporting requirements. Climate change and greenhouse gas initiatives, and incentives to conserve energy or use alternative energy sources, could also reduce demand for oil and natural gas. The effect (material or not) on the Company of any new legislative or regulatory measures will depend on the particular provisions that are ultimately adopted.

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

On October 1, 2010, the Company issued a total of 3,600 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, 400 shares to each such director. All of these unregistered shares were issued under the Company s Retainer Policy for Non-Employee Directors or the Company s 2009 Non-Employee Director Equity Compensation Plan as partial consideration for such directors services during the quarter ended December 31, 2010. 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]
Oct. 1-31, 2010	99,753	$ 54.37		6,971,019
Nov. 1-30, 2010	95,433	$ 62.64		6,971,019
Dec. 1-31, 2010	95,197	$ 65.28		6,971,019
Total	290,383	$ 60.66		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 or shares of restricted stock for the payment of option exercise prices or applicable withholding taxes. During the quarter ended December 31, 2010, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program. Of the 290,383 shares purchased other than through a publicly announced share repurchase program, 20,408 were purchased for the Company s 401(k) plans and 269,975 were purchased as a result of shares tendered to the Company by holders of stock options 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 in light of the unsettled nature of the credit markets. Since that time, the Company has increased its emphasis on Marcellus Shale development and pipeline expansion. As such, the Company does not anticipate repurchasing any shares in the near future.

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Item 6. Exhibits

(a) Exhibits

Exhibit Number	Description of Exhibit
10.1	Description of long-term performance incentives under the National Fuel Gas Company Performance Incentive Program.
10.2	Description of performance goals under the Amended and Restated National Fuel Gas Company 2007 Annual At Risk Compensation Incentive Program and the National Fuel Gas Company Executive Annual Cash Incentive Program.
10.3	Form of Restricted Stock Award Notice under the National Fuel Gas Company 1997 Award and Option Plan.
10.4	Form of Stock Appreciation Right Award Notice under the National Fuel Gas Company 2010 Equity Compensation Plan.
10.5	Administrative Rules of the Compensation Committee of the Board of Directors of National Fuel Gas Company, as amended and restated effective December 8, 2010.
12	Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the Twelve Months Ended December 31, 2010 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 December 31, 2010 and 2009.
101	Interactive data files pursuant to Regulation S-T: (i) the Consolidated Statements of Income and Earnings Reinvested in the Business for the three months ended December 31, 2010 and 2009, (ii) the Consolidated Balance Sheets at December 31, 2010 and September 30, 2010, (iii) the Consolidated Statements of Cash Flows for the three months ended December 31, 2010 and 2009, (iv) the Consolidated Statements of Comprehensive Income for the three months ended December 31, 2010 and 2009 and (v) the Notes to Condensed Consolidated Financial Statements.

SIGNATURE

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: February 4, 2011