NATIONAL FUEL GAS CO
Form 10-Q
August 07, 2009

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 June 30, 2009

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 o NO o

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

Large accelerated filer 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 July 31, 2009: 80,234,282 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
Data-Track	Data-Track Account Services, Inc.
Distribution Corporation	National Fuel Gas Distribution Corporation
Empire	Empire Pipeline, Inc.
ESNE	Energy Systems North East, LLC
Highland	Highland Forest Resources, Inc.
Horizon	Horizon Energy Development, Inc.
Horizon LFG	Horizon LFG, Inc.
Horizon Power	Horizon Power, Inc.
Leidy Hub	Leidy Hub, 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
SECI	Seneca Energy Canada Inc.
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	
2008 Form 10-K	The Company s Annual Report on Form 10-K for the year ended September 30, 2008, as amended
ARB 51	Accounting Research Bulletin No. 51, Consolidated Financial Statements
Bbl	Barrel (of oil)
Bcf	Billion cubic feet (of natural gas)
Board foot	A measure of lumber and/or timber equal to 12 inches in length by 12 inches in width by one inch in thickness.
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

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.
FIN	FASB Interpretation Number
FIN 48	FASB Interpretation No. 48, Accounting for Uncertainty in Income Taxes an interpretation of SFAS 109
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
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)
NYMEX	New York Mercantile Exchange. An exchange which maintains a futures market for crude oil and natural gas.
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 industries by a statutory or regulatory process. Restructuring of federally regulated natural gas pipelines has 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.
S&P	Standard & Poor s Ratings Service
SAR	Stock-settled stock appreciation right
SFAS	Statement of Financial Accounting Standards
SFAS 87	Statement of Financial Accounting Standards No. 87, Employers Accounting for Pensions
SFAS 88	Statement of Financial Accounting Standards No. 88, Employers Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits
SFAS 106	Statement of Financial Accounting Standards No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions
SFAS 109	Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes

GLOSSARY OF TERMS (Concl.)

SFAS 123R	Statement of Financial Accounting Standards No. 123R, Share-Based Payment
SFAS 131	Statement of Financial Accounting Standards No. 131, Disclosures about Segments of an Enterprise and Related Information
SFAS 132R	Statement of Financial Accounting Standards No. 132R, Employers Disclosures about Pensions and Other Postretirement Benefits
SFAS 133	Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities
SFAS 141R	Statement of Financial Accounting Standards No. 141R, Business Combinations
SFAS 157	Statement of Financial Accounting Standards No. 157, Fair Value Measurements
SFAS 158	Statement of Financial Accounting Standards No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an Amendment of SFAS 87, 88, 106, and 132R
SFAS 160	Statement of Financial Accounting Standards No. 160, Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB 51
SFAS 161	Statement of Financial Accounting Standards No. 161, Disclosures about Derivative Instruments and Hedging Activities, an Amendment of SFAS 133
SFAS 165	Statement of Financial Accounting Standards No. 165, Subsequent Events
SFAS 168	Statement of Financial Accounting Standards No. 168, The FASB Accounting Standards Codification ™ and the Hierarchy of Generally Accepted Accounting Principles a Replacement of FASB Statement No. 162
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, 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, believes, seeks, will, may, and similar expressions.

Part I. Financial Information
Item 1. Financial Statements

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

(Thousands of Dollars, Except Per Common Share Amounts)	Three Months Ended June 30, 2009	2008
INCOME		
Operating Revenues	$ 367,111	$ 548,382
Operating Expenses		
Purchased Gas	126,969	272,893
Operation and Maintenance	90,821	102,602
Property, Franchise and Other Taxes	17,576	19,135
Depreciation, Depletion and Amortization	43,659	42,804
	279,025	437,434
Operating Income	88,086	110,948
Other Income (Expense):		
Income from Unconsolidated Subsidiaries	627	1,561
Interest Income	1,460	3,086
Other Income	664	1,649
Interest Expense on Long-Term Debt	(21,756)	(19,468)
Other Interest Expense	(2,539)	(1,199)
Income Before Income Taxes	66,542	96,577
Income Tax Expense	23,638	36,722
Net Income Available for Common Stock	42,904	59,855
EARNINGS REINVESTED IN THE BUSINESS		
Balance at April 1	932,119	1,008,084
	975,023	1,067,939
Share Repurchases		(17,083)
Dividends on Common Stock (2009 $0.335 per share; 2008 $0.325 per share)	(26,761)	(26,479)
Balance at June 30	$ 948,262	$ 1,024,377

Earnings Per Common Share:		
Basic:		
Net Income Available for Common Stock	$ 0.54	$ 0.74
Diluted:		
Net Income Available for Common Stock	$ 0.53	$ 0.72
Weighted Average Common Shares Outstanding:		
Used in Basic Calculation	79,551,195	81,342,788
Used in Diluted Calculation	80,391,402	83,712,193

See Notes to Condensed Consolidated Financial Statements

Item 1. Financial Statements (Cont.)

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

(Thousands of Dollars, Except Per Common Share Amounts)	Nine Months Ended June 30, 2009	2008
INCOME		
Operating Revenues	$ 1,778,919	$ 2,002,503
Operating Expenses		
Purchased Gas	941,171	1,082,340
Operation and Maintenance	310,605	325,642
Property, Franchise and Other Taxes	56,709	58,206
Depreciation, Depletion and Amortization	127,715	129,337
Impairment of Oil and Gas Producing Properties	182,811	
	1,619,011	1,595,525
Operating Income	159,908	406,978
Other Income (Expense):		
Income from Unconsolidated Subsidiaries	915	4,866
Interest Income	4,358	8,356
Other Income	6,459	4,982
Interest Expense on Long-Term Debt	(57,357)	(52,045)
Other Interest Expense	(5,013)	(4,209)
Income Before Income Taxes	109,270	368,928
Income Tax Expense	35,560	143,465
Net Income Available for Common Stock	73,710	225,463
EARNINGS REINVESTED IN THE BUSINESS		
Balance at October 1	953,799	983,776
	1,027,509	1,209,239
Share Repurchases		(106,647)
Cumulative Effect of the Adoption of FIN 48		(406)
Adoption of SFAS 158 Measurement Date Provision	(804)	
Dividends on Common Stock (2009 $0.985 per share; 2008 $0.945 per share)	(78,443)	(77,809)
Balance at June 30	$ 948,262	$ 1,024,377

Earnings Per Common Share:		
Basic:		
Net Income Available for Common Stock	$ 0.93	$ 2.72
Diluted:		
Net Income Available for Common Stock	$ 0.92	$ 2.65
Weighted Average Common Shares Outstanding:		
Used in Basic Calculation	79,450,838	82,789,748
Used in Diluted Calculation	80,248,787	85,000,381

See Notes to Condensed Consolidated Financial Statements

Item 1. Financial Statements (Cont.)

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

(Thousands of Dollars)	June 30, 2009	September 30, 2008
ASSETS		
Property, Plant and Equipment	$5,078,088	$4,873,969
Less Accumulated Depreciation, Depletion and Amortization	2,010,584	1,719,869
	3,067,504	3,154,100
Current Assets		
Cash and Temporary Cash Investments	433,230	68,239
Cash Held in Escrow	2,000	
Hedging Collateral Deposits	6,359	1
Receivables Net of Allowance for Uncollectible Accounts of $45,209 and $33,117, Respectively	200,594	185,397
Unbilled Utility Revenue	14,568	24,364
Gas Stored Underground	27,721	87,294
Materials and Supplies at average cost	24,768	31,317
Unrecovered Purchased Gas Costs	1,900	37,708
Other Current Assets	32,477	65,158
Deferred Income Taxes	33,009	
	776,626	499,478
Other Assets		
Recoverable Future Taxes	83,543	82,506
Unamortized Debt Expense	15,345	13,978
Other Regulatory Assets	196,278	189,587
Deferred Charges	1,790	4,417
Other Investments	73,174	80,640
Investments in Unconsolidated Subsidiaries	15,094	16,279
Goodwill	5,476	5,476
Intangible Assets	24,627	26,174
Prepaid Post-Retirement Benefit Costs	21,738	21,034
Fair Value of Derivative Financial Instruments	66,193	28,786
Other	7,914	7,732
	511,172	476,609
Total Assets	$4,355,302	$4,130,187

See Notes to Condensed Consolidated Financial Statements

Item 1. Financial Statements (Cont.)

National Fuel Gas Company
Consolidated Balance Sheets
(Unaudited)

	June 30, 2009	September 30, 2008
(Thousands of Dollars)		
CAPITALIZATION AND LIABILITIES		
Capitalization:		
Comprehensive Shareholders Equity		
Common Stock, $1 Par Value Authorized 200,000,000 Shares; Issued and Outstanding 79,881,482 Shares and 79,120,544 Shares, Respectively	$ 79,881	$ 79,121
Paid in Capital	589,295	567,716
Earnings Reinvested in the Business	948,262	953,799
Total Common Shareholder Equity Before Items of Other Comprehensive Income	1,617,438	1,600,636
Accumulated Other Comprehensive Income	17,234	2,963
Total Comprehensive Shareholders Equity	1,634,672	1,603,599
Long-Term Debt, Net of Current Portion	1,249,000	999,000
Total Capitalization	2,883,672	2,602,599
Current and Accrued Liabilities		
Notes Payable to Banks and Commercial Paper		
Current Portion of Long-Term Debt		100,000
Accounts Payable	69,762	142,520
Amounts Payable to Customers	45,772	2,753
Dividends Payable	26,761	25,714
Interest Payable on Long-Term Debt	18,722	22,114
Customer Advances	3,229	33,017
Other Accruals and Current Liabilities	198,057	45,220
Deferred Income Taxes		1,871
Fair Value of Derivative Financial Instruments	1,815	1,362
	364,118	374,571
Deferred Credits		
Deferred Income Taxes	589,380	634,372
Taxes Refundable to Customers	18,459	18,449
Unamortized Investment Tax Credit	4,165	4,691
Cost of Removal Regulatory Liability	107,245	103,100
Other Regulatory Liabilities	115,617	91,933

Pension and Other Post-Retirement Liabilities	61,404	78,909
Asset Retirement Obligations	86,559	93,247
Other Deferred Credits	124,683	128,316
	1,107,512	1,153,017
Commitments and Contingencies		
Total Capitalization and Liabilities	$4,355,302	$4,130,187

See Notes to Condensed Consolidated Financial Statements

Item 1. Financial Statements (Cont.)

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

(Thousands of Dollars)	Nine Months Ended June 30, 2009	2008
OPERATING ACTIVITIES		
Net Income Available for Common Stock	$ 73,710	$ 225,463
Adjustments to Reconcile Net Income to Net Cash Provided by Operating Activities:		
Impairment of Oil and Gas Producing Properties	182,811	
Depreciation, Depletion and Amortization	127,715	129,337
Deferred Income Taxes	(85,494)	27,603
Income from Unconsolidated Subsidiaries, Net of Cash Distributions	180	1,340
Impairment of Investment in Partnership	1,804	
Excess Tax Benefits Associated with Stock-Based Compensation Awards	(5,927)	(16,275)
Other	9,365	(1,120)
Change in:		
Hedging Collateral Deposits	(6,358)	(26,712)
Receivables and Unbilled Utility Revenue	(5,520)	(129,102)
Gas Stored Underground and Materials and Supplies	71,491	14,819
Unrecovered Purchased Gas Costs	35,808	9,089
Prepayments and Other Current Assets	37,904	17,370
Accounts Payable	(82,146)	53,081
Amounts Payable to Customers	43,019	2,455
Customer Advances	(29,788)	(22,863)
Other Accruals and Current Liabilities	166,217	94,031
Other Assets	(8,517)	19,178
Other Liabilities	(14,453)	17,373
Net Cash Provided by Operating Activities	511,821	415,067
INVESTING ACTIVITIES		
Capital Expenditures	(237,126)	(264,728)
Investment in Partnership	(800)	
Cash Held in Escrow	(2,000)	58,397
Net Proceeds from Sale of Oil and Gas Producing Properties	3,701	5,675
Other	(1,674)	(3,414)
Net Cash Used in Investing Activities	(237,899)	(204,070)
FINANCING ACTIVITIES		
Excess Tax Benefits Associated with Stock-Based Compensation Awards	5,927	16,275

Shares Repurchased under Repurchase Plan		(129,592)
Net Proceeds from Issuance of Long-Term Debt	247,780	296,655
Reduction of Long-Term Debt	(100,000)	(200,024)
Dividends Paid on Common Stock	(77,398)	(77,204)
Net Proceeds from Issuance of Common Stock	14,760	17,285
Net Cash Provided by (Used in) Financing Activities	91,069	(76,605)
Net Increase in Cash and Temporary Cash Investments	364,991	134,392
Cash and Temporary Cash Investments at October 1	68,239	124,806
Cash and Temporary Cash Investments at June 30	$ 433,230	$ 259,198

See Notes to Condensed Consolidated Financial Statements

Item 1. Financial Statements (Cont.)

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

(Thousands of Dollars)	Three Months Ended June 30, 2009	2008
Net Income Available for Common Stock	$ 42,904	$ 59,855
Other Comprehensive Loss, Before Tax:		
Foreign Currency Translation Adjustment	(42)	2
Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	3,775	(1,603)
Unrealized Loss on Derivative Financial Instruments Arising During the Period	(24,446)	(139,684)
Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	(24,853)	33,082
Other Comprehensive Loss, Before Tax	(45,566)	(108,203)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Securities Available for Sale Arising During the Period	1,429	(608)
Income Tax Benefit Related to Unrealized Loss on Derivative Financial Instruments Arising During the Period	(9,950)	(57,136)
Reclassification Adjustment for Income Tax (Expense) Benefit on Realized (Gains) Losses from Derivative Financial Instruments in Net Income	(10,108)	13,546
Income Taxes Net	(18,629)	(44,198)
Other Comprehensive Loss	(26,937)	(64,005)
Comprehensive Income (Loss)	$ 15,967	$ (4,150)

(Thousands of Dollars)	Nine Months Ended June 30, 2009	2008
Net Income Available for Common Stock	$ 73,710	$ 225,463
Other Comprehensive Income (Loss), Before Tax:		
Foreign Currency Translation Adjustment	(1)	(72)
Unrealized Loss on Securities Available for Sale Arising During the Period	(9,202)	(4,817)
Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	127,357	(208,256)

Reclassification Adjustment for Realized (Gains) Losses on Derivative Financial Instruments in Net Income	(93,260)	45,242
Other Comprehensive Income (Loss), Before Tax	24,894	(167,903)
Income Tax Benefit Related to Unrealized Loss on Securities Available for Sale Arising During the Period	(3,475)	(1,429)
Income Tax Expense (Benefit) Related to Unrealized Gain (Loss) on Derivative Financial Instruments Arising During the Period	51,576	(85,300)
Reclassification Adjustment for Income Tax (Expense) Benefit on Realized (Gains) Losses on Derivative Financial Instruments in Net Income	(37,478)	18,495
Income Taxes Net	10,623	(68,234)
Other Comprehensive Income (Loss)	14,271	(99,669)
Comprehensive Income	$ 87,981	$ 125,794

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.

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, 2008, 2007 and 2006 that are included in the Company s 2008 Form 10-K. The consolidated financial statements for the year ended September 30, 2009 will be audited by the Company s independent registered public accounting firm after the end of the fiscal year.

The earnings for the nine months ended June 30, 2009 should not be taken as a prediction of earnings for the entire fiscal year ending September 30, 2009. Most of the business of the Utility and Energy Marketing segments is seasonal in nature and is influenced by weather conditions. Due to the seasonal nature of the heating business in the Utility and Energy Marketing segments, earnings during the winter months normally represent a substantial part of the earnings that those segments are expected to achieve for the entire fiscal year. The Company s business segments are discussed more fully in Note 7 Business Segment Information.

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

At June 30, 2009, the Company accrued $9.4 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 June 30, 2009 since it represents a non-cash investing activity at that date.

At September 30, 2008, the Company accrued $16.8 million of capital expenditures related to the construction of the Empire Connector project. This amount was excluded from the Consolidated Statement of Cash Flows at September 30, 2008 since it represented a non-cash investing activity at that date. These capital expenditures were paid during the quarter ended December 31, 2008 and have been included in the Consolidated Statement of Cash Flows for the nine months ended June 30, 2009.

Hedging Collateral Deposits. This is an account title for cash held in margin accounts funded by the Company to serve as collateral for open hedging positions. At June 30, 2009, the Company had hedging collateral deposits of $6.4 million related to its exchange-traded futures contracts. It is the Company s policy to not offset hedging collateral deposits paid or received against the derivative financial instruments liability or asset balances.

Cash Held in Escrow. On July 20, 2009, the Company announced that in its Exploration and Production segment, Seneca had purchased Ivanhoe Energy s United States oil and gas operations for approximately $39.2 million, of which $2 million was placed in escrow as a deposit for the acquisition as of June 30, 2009.

Item 1. Financial Statements (Cont.)

On August 31, 2007, the Company received approximately $232.1 million of proceeds from the sale of SECI, of which $58.0 million was placed in escrow pending receipt of a tax clearance certificate from the Canadian government. The escrow account was a Canadian dollar denominated account. On a U.S. dollar basis, the value of this account was $62.0 million at September 30, 2007. In December 2007, the Canadian government issued the tax clearance certificate, thereby releasing the proceeds from restriction as of December 31, 2007. To hedge against foreign currency exchange risk related to the cash being held in escrow, the Company held a forward contract to sell Canadian dollars. For presentation purposes on the Consolidated Statement of Cash Flows, for the nine months ended June 30, 2008, the Cash Held in Escrow line item within Investing Activities reflects the net proceeds to the Company (received on January 8, 2008) after adjusting for the impact of the foreign currency hedge.

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 $116.5 million at June 30, 2009, 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. 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 computed by applying current market 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. 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. The Company s capitalized costs exceeded the full cost ceiling for the Company s oil and gas properties at December 31, 2008. As such, the Company recognized a pre-tax impairment of $182.8 million at December 31, 2008. Deferred income taxes of $74.6 million were recorded associated with this impairment.

Item 1. Financial Statements (Cont.)

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

	At June 30, 2009	At September 30, 2008
Funded Status of the Pension and Other Post-Retirement Benefit Plans	$ (19,741)	$ (19,741)
Cumulative Foreign Currency Translation Adjustment	(72)	(71)
Net Unrealized Gain on Derivative Financial Instruments	35,948	15,949
Net Unrealized Gain on Securities Available for Sale	1,099	6,826
Accumulated Other Comprehensive Income	$ 17,234	$ 2,963

Earnings Per Common Share. Basic earnings per common share is computed by dividing income available for common stock by the weighted average number of common shares outstanding for the period. Diluted earnings per common share reflects the potential dilution that could occur if securities or other contracts to issue common stock were exercised or converted into common stock. For purposes of determining earnings per common share, the only potentially dilutive securities the Company has outstanding are stock options and stock-settled SARs. The diluted weighted average shares outstanding shown on the Consolidated Statements of Income reflects the potential dilution as a result of these stock options and stock-settled SARs as determined using the Treasury Stock Method. Stock options and stock-settled SARs that are antidilutive are excluded from the calculation of diluted earnings per common share. For both the quarter and nine months ended June 30, 2009, there were 765,000 stock options excluded as being antidilutive. In addition, there were 365,000 stock-settled SARs excluded as being antidilutive for both the quarter and nine months ended June 30, 2009. For the quarter and nine months ended June 30, 2008, there were 6,593 and 2,190 stock-settled SARs excluded as being antidilutive, respectively. There were no stock options excluded as being antidilutive for the quarter and nine months ended June 30, 2008.

Share Repurchases. The Company considers all shares repurchased as cancelled shares restored to the status of authorized but unissued shares, in accordance with New Jersey law. The repurchases are accounted for on the date the share repurchase is settled as an adjustment to common stock (at par value) with the excess repurchase price allocated between paid in capital and retained earnings.

Stock-Based Compensation. During the nine months ended June 30, 2009, the Company granted 610,000 performance-based stock-settled SARs having a weighted average exercise price of $29.88 per share. The weighted average grant date fair value of these stock-settled SARs was $4.09 per share. There were no stock-settled SARs granted during the quarter ended June 30, 2009. The accounting treatment for such stock-settled SARs is the same under SFAS 123R as the accounting for stock options under SFAS 123R. The stock-settled SARs granted during the nine months ended June 30, 2009 vest and become exercisable annually in one-third increments, provided that a performance condition is met. The performance condition for each fiscal year, generally stated, is an increase over the prior fiscal year of at least five percent in certain oil and natural gas production of the Exploration and Production segment. The weighted average grant date fair value of these stock-settled SARs granted during the nine months ended June 30, 2009 was estimated on the date of grant using the same accounting treatment that is applied for stock options under SFAS 123R, and assumes that the performance conditions specified will be achieved. If such conditions are not met or it is not considered probable that such conditions will be met, no compensation expense is recognized and any previously recognized compensation expense is reversed.

There were no stock options or restricted share awards (non-vested stock as defined in SFAS 123R) granted during the quarter and nine months ended June 30, 2009.

Item 1. Financial Statements (Cont.)

New Accounting Pronouncements. In September 2006, the FASB issued SFAS 157, Fair Value Measurements . SFAS 157 provides guidance for using fair value to measure assets and liabilities. The pronouncement serves to clarify the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value, and the effect that fair-value measurements have on earnings. SFAS 157 is to be applied whenever another standard requires or allows assets or liabilities to be measured at fair value. In accordance with FASB Staff Position FAS No. 157-2, on October 1, 2008, the Company adopted SFAS 157 for financial assets and financial liabilities that are recognized or disclosed at fair value on a recurring basis. The same FASB Staff Position delays the effective date for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value on a recurring basis, until the Company s first quarter of fiscal 2010. For further discussion of the impact of the adoption of SFAS 157 for financial assets and financial liabilities, refer to Note 2 Fair Value Measurements. The Company is currently evaluating the impact that the adoption of SFAS 157 for nonfinancial assets and nonfinancial liabilities will have on its consolidated financial statements. The Company has identified Goodwill as being the major nonfinancial asset that may be impacted by the adoption of SFAS 157. The Company does not believe there are any nonfinancial liabilities that will be impacted by the adoption of SFAS 157.

In September 2006, the FASB issued SFAS 158, Employer s Accounting for Defined Benefit Pension and Other Postretirement Plans (an amendment of SFAS 87, SFAS 88, SFAS 106, and SFAS 132R). SFAS 158 requires that companies recognize a net liability or asset to report the underfunded or overfunded status of their defined benefit pension and other post-retirement benefit plans on their balance sheets, as well as recognize changes in the funded status of a defined benefit post-retirement plan in the year in which the changes occur through comprehensive income. The pronouncement also specifies that a plan s assets and obligations that determine its funded status be measured as of the end of the Company s fiscal year, with limited exceptions. In accordance with SFAS 158, the Company has recognized the funded status of its benefit plans and implemented the disclosure requirements of SFAS 158 at September 30, 2007. The requirement to measure the plan assets and benefit obligations as of the Company s fiscal year-end date will be fully adopted by the Company by the end of fiscal 2009. The Company has historically measured its plan assets and benefit obligations using a June 30th measurement date. In anticipation of changing to a September 30th measurement date, the Company will be recording fifteen months of pension and other post-retirement benefit costs during fiscal 2009. In accordance with the provisions of SFAS 158, these costs have been calculated using June 30, 2008 measurement date data. Three of those months pertain to the period of July 1, 2008 to September 30, 2008. The pension and other post-retirement benefit costs for that period amounted to $5.1 million and have been recorded by the Company during the quarter ended December 31, 2008 as a $3.8 million increase to Other Regulatory Assets in the Company s Utility and Pipeline and Storage segments and a $1.3 million ($0.8 million after tax) adjustment to earnings reinvested in the business. For further discussion of the impact of adopting the measurement date provisions of SFAS 158, refer to Note 9 Retirement Plan and Other Post-Retirement Benefits.

In December 2007, the FASB issued SFAS 141R, Business Combinations. SFAS 141R will significantly change the accounting for business combinations in a number of areas including the treatment of contingent consideration, contingencies, acquisition costs, in process research and development and restructuring costs. In addition, under SFAS 141R, changes in deferred tax asset valuation allowances and acquired income tax uncertainties in a business combination after the measurement period will impact income tax expense. SFAS 141R is effective as of the Company s first quarter of fiscal 2010.

In December 2007, the FASB issued SFAS 160, Noncontrolling Interests in Consolidated Financial Statements, an Amendment of ARB 51. SFAS 160 will change the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests (NCI) and classified as a component of equity. This new consolidation method will significantly change the accounting for transactions with minority interest holders. SFAS 160 is effective as of the Company s first quarter of fiscal 2010. The Company currently does not have any NCI.

Item 1. Financial Statements (Cont.)

In March 2008, the FASB issued SFAS 161, Disclosures about Derivative Instruments and Hedging Activities, an Amendment of SFAS 133. SFAS 161 requires entities to provide enhanced disclosures related to an entity s derivative instruments and hedging activities in order to enable investors to better understand how derivative instruments and hedging activities impact an entity s financial reporting. The additional disclosures include how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. The Company adopted the disclosure provisions of SFAS 161 during the quarter ended March 31, 2009. These disclosures may be found at Note 3 Financial Instruments.

On December 31, 2008, the SEC issued a final rule on Modernization of Oil and Gas Reporting. The final rule modifies the SEC s reporting and disclosure rules for oil and gas reserves and aligns the full cost accounting rules with the revised disclosures. The most notable changes of the final rule include the replacement of the single day period-end pricing to value oil and gas reserves to a 12-month average of the first day of the month price for each month within the reporting period. The final rule also permits voluntary disclosure of probable and possible reserves, a disclosure previously prohibited by SEC rules. The revised reporting and disclosure requirements are effective for the Company s Form 10-K for the period ended September 30, 2010. Early adoption is not permitted. The Company is currently evaluating the impact that adoption of these rules will have on its consolidated financial statements and MD&A disclosures.

Effective April 1, 2009, the Company adopted FASB Staff Position FAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments. This FASB Staff Position amends SFAS 107, Disclosures about Fair Value of Financial Instruments, to require disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. Refer to Note 3 Financial Instruments under Long-Term Debt for additional disclosures included in accordance with this FASB Staff Position.

Effective with this June 30, 2009 Form 10-Q, the Company adopted SFAS 165, Subsequent Events. SFAS 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Refer to Note 10 Subsequent Events for disclosures made as a result of the adoption of SFAS 165.

In June 2009, the FASB issued SFAS 168, The FASB Accounting Standards Codification™ and the Hierarchy of Generally Accepted Accounting Principles a replacement of FASB Statement No. 162. SFAS 168 establishes the FASB Accounting Standards Codification™ (the Codification) as the source of authoritative GAAP recognized by the FASB to be applied by all nongovernmental entities in the preparation of financial statements in conformity with GAAP. Rules and interpretive releases of the SEC under authority of federal securities law are also sources of authoritative GAAP for SEC registrants. All other nongrandfathered, non-SEC accounting literature not included in the Codification will become nonauthoritative. SFAS 168 is effective for interim and annual periods ending after September 15, 2009. The Company will update its disclosures to conform to the Codification in its annual report on Form 10-K for the year ending September 30, 2009. There will be no impact on the Company s consolidated financial statements as the Codification does not change or alter existing GAAP.

Note 2 Fair Value Measurements

Beginning in fiscal 2009, the Company adopted the provisions of SFAS 157, Fair Value Measurements. SFAS 157 establishes a fair-value hierarchy, which 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

Item 1. Financial Statements (Cont.)
may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. The adoption of SFAS 157 has not had a significant impact on the consolidated financial statements.

The following table sets forth, by level within the fair value hierarchy, the Company s financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2009. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement.

Recurring Fair Value Measures	At fair value as of June 30, 2009			
(Dollars in thousands)	Level 1	Level 2	Level 3	Total
Assets:				
Cash Equivalents	$412,255	$	$	$412,255
Derivative Financial Instruments		31,647	34,546	66,193
Other Investments	19,691			19,691
Hedging Collateral Deposits	6,359			6,359
Total	$438,305	$31,647	$34,546	$504,498
Liabilities:				
Derivative Financial Instruments	$ 1,815	$	$	$ 1,815
Total	$ 1,815	$	$	$ 1,815

Cash Equivalents

The cash equivalents reported in Level 1 consist of SEC registered money market mutual funds.

Derivative Financial Instruments

The derivative financial instruments reported in Level 1 consist of NYMEX futures contracts. The hedging collateral deposits associated with these futures contracts have been reported in Level 1 as well. The derivative financial instruments reported in Level 2 consist of natural gas swap agreements used in the Company s Exploration and Production segment and natural gas swap agreements used in the Energy Marketing segment. The fair value of these natural gas swap agreements is based on an internal model that uses observable inputs. The fair market value of the price swap agreements reported in Level 2 as assets has been reduced by $0.6 million based on an assessment of counterparty credit risk. The derivative financial instruments reported in Level 3 consist of all of the Exploration and Production segment s crude oil swap agreements and some of its natural gas swap agreements. The fair value of the crude oil and natural gas swap agreements is based on an internal model that uses both observable and unobservable inputs. The fair market value of the price swap agreements reported in Level 3 as assets has been reduced by $0.7 million based on an assessment of counterparty credit risk. This credit reserve, as well as the credit reserve established for the Level 2 swap agreement assets, was 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.

Other Investments

The other investments reported in Level 1 consist of publicly traded equity securities and a publicly traded balanced equity mutual fund.

The table listed below provides a reconciliation of the beginning and ending net balances for assets and liabilities measured at fair value and classified as Level 3.

Item 1. Financial Statements (Cont.)

Fair Value Measurements Using Unobservable Inputs (Level 3)

(Dollars in thousands)	October 1, 2008	Total Gains/Losses Realized and Unrealized Included in Earnings	Included in Other Comprehensive Income	Transfer In/(Out) of Level 3	June 30, 2009
Assets:					
Derivative Financial Instruments	$7,110	$(37,339)[1]	$ 73,267	$ (8,492)	$34,546
Total	$7,110	$(37,339)	$ 73,267	$ (8,492)	$34,546
Liabilities:					
Derivative Financial Instruments	$ (777)	$(12,104)[1]	$ 12,881	$	$
Total	$ (777)	$(12,104)	$ 12,881	$	$

(1) Amounts are reported in Operating Revenues in the Consolidated Statement of Income for the nine months ended June 30, 2009.

Note 3 Financial Instruments

Long-Term Debt. In accordance with the Company s adoption of FASB Staff Position FAS 107-1 and APB 28-1 Disclosures about Fair Value of Financial Instruments , the fair value of the Company s long-term debt, including current portion, and the carrying amount is presented below:

	June 30, 2009 Carrying Amount	June 30, 2009 Fair Value	September 30, 2008 Carrying Amount	September 30, 2008 Fair Value
Long-Term Debt	$1,249,000	$1,285,890	$1,099,000	$1,027,098

At September 30, 2008, the fair market value of the Company s long-term debt was determined based on quoted market prices of similar issues having the same remaining maturities, redemption terms and credit rating. At June 30, 2009, the fair market value of the Company s debt, as presented in the table above, was determined using a discounted cash flow model, which incorporates the Company s credit risk in determining the yield, and subsequently, the fair market value of the debt.

Other Investments. 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 $53.5 million at June 30, 2009 and $53.6 million at September 30, 2008. The fair value of the equity mutual fund was $12.6 million at June 30, 2009 and $12.4 million at September 30, 2008. The gross unrealized loss on this equity mutual fund was $2.7 million at June 30, 2009 and $1.1 million at September 30, 2008. Although this investment has been in an unrealized loss position for twelve months, management has the intent and ability to hold the investment for a sufficient period of time for the asset to recover in value. As such, management does not consider this investment to be other than temporarily impaired. The fair value of the stock of an insurance company was $6.9 million at June 30, 2009 and $14.5 million at September 30, 2008. The gross unrealized gain on this stock was $4.5 million at June 30, 2009 and $12.1 million at September 30, 2008. The insurance contracts and marketable equity securities are primarily informal funding mechanisms for various benefit obligations the Company has to certain employees.

Item 1. Financial Statements (Cont.)

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 and Energy Marketing 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, and withdrawal of gas from storage to meet customer demand. The duration of the Company s hedges do not typically exceed 3 years and the majority of the positions settle within one year.

In accordance with the adoption of SFAS 161, Disclosures about Derivative Instruments and Hedging Activities, an Amendment of SFAS 133 , the Company has presented its gross derivative assets and liabilities in the table below.

Derivatives Designated as Hedging Instruments under SFAS 133	Fair Values of Derivative Instruments (Dollar Amounts in Thousands) Asset Derivatives June 30, 2009 Consolidated Balance Sheet Location	Fair Value	Liability Derivatives June 30, 2009 Consolidated Balance Sheet Location	Fair Value
Commodity Contracts	Fair Value of Derivative Financial Instruments	$66,193(1)	Fair Value of Derivative Financial Instruments	$1,815(2)

(1) Agrees to the sum of Level 2 and Level 3 Derivative Financial Instrument Assets shown in Note 2, Fair Value Measurements.

(2) Agrees to the Level 1 Derivative Financial Instrument Liabilities shown in Note 2, Fair Value Measurements.

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 and reclassified into earnings in the same period or periods during which the hedged transaction affects earnings. Gains and losses on the derivative representing either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in current earnings.

As of June 30, 2009, 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	20.7 Bcf (all short positions)
Crude Oil	2,199,000 Bbls (all short positions)

Item 1. Financial Statements (Cont.)

As of June 30, 2009, 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	7.0 Bcf (5.5 Bcf short positions (forecasted storage withdrawals) and 1.5 Bcf long positions (forecasted storage injections))

As of June 30, 2009, the Company s Exploration and Production segment had $63.6 million ($37.6 million after tax) of gains included in the accumulated other comprehensive income balance. It is expected that $51.4 million ($30.4 million after tax) of these gains will be reclassified into income within the next 12 months as the sales of the underlying commodities are expected to occur. See Note 1, under Accumulated Other Comprehensive Income, for the after-tax gain pertaining to derivative financial instruments (Net Unrealized Gain on Derivative Financial Instruments in Note 1 includes both the Exploration and Production and Energy Marketing segments).

As of June 30, 2009, the Company s Energy Marketing segment had $2.8 million ($1.7 million after tax) of losses included in the accumulated other comprehensive income balance. It is expected that $2.8 million ($1.7 million after tax) of these losses will be reclassified into income within the next 12 months as the sales and purchases of the underlying commodities occur. See Note 1, under Accumulated Other Comprehensive Income, for the after-tax gain pertaining to derivative financial instruments (Net Unrealized Gain on Derivative Financial Instruments in Note 1 includes both the Exploration and Production and Energy Marketing segments).

Item 1. Financial Statements (Cont.)

The Effect of Derivative Financial Instruments on the Statement of Financial Performance for the Nine Months Ended June 30, 2009 (Dollar Amounts in Thousands)

Derivatives in SFAS 133 Cash Flow Hedging Relationships	Amount of Derivative Gain or (Loss) Recognized in Other Comprehensive Income on the Consolidated Statement of Comprehensive Income (Effective Portion) for the Nine Months Ended June 30, 2009	Location of Derivative Gain or (Loss) Reclassified from Accumulated Other Comprehensive Income on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion)	Amount of Derivative Gain or (Loss) Reclassfied from Accumulated Other Comprehensive Income on the Consolidated Balance Sheet into the Consolidated Statement of Income (Effective Portion) for the Nine Months Ended June 30, 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 Nine Months Ended June 30, 2009
Commodity Contracts Exploration & Production segment	$ 117,764	Operating Revenue	$ 71,324	Operating Revenue	$ 424
Commodity Contracts Energy Marketing segment	$ 9,410	Purchased Gas	$ 21,328	Operating Revenue	$
Commodity Contracts Pipeline & Storage segment [(1)]	$	Operating Revenue	$ 1,290	Operating Revenue	$
Commodity Contracts All Other [(1)]	$ 183	Purchased Gas	$ (682)	Purchased Gas	$
Total	$ 127,357		$ 93,260		$ 424

(1) There were no open hedging positions at June 30, 2009.

As such there is no mention of these positions in the preceding sections of this footnote.

Fair value hedges

The Company s Energy Marketing segment is the only segment which utilizes fair value hedges to mitigate risk associated with fixed price sales commitments, fixed price purchase commitments, and commitments related to the injection and withdrawal of storage gas. In order to hedge fixed price sales commitments, the Company enters into long positions to mitigate the risk that after the Company locks into fixed price sales agreements with its customers, the price of natural gas increases (thereby passing up the opportunity for higher operating revenue). With fixed price purchase commitments, the risk is that

Item 1. Financial Statements (Cont.)
after the Company locks into fixed price purchase deals with its suppliers, the price of natural gas decreases (thereby passing up the opportunity for lower purchased gas expense). Fair value hedges related to the injection and withdrawal of storage gas impact purchased gas expense. As of June 30, 2009, the Company s Energy Marketing segment had fair value hedges covering approximately 13.4 Bcf (11.6 Bcf of fixed price sales commitments (all long positions), 1.3 Bcf of fixed price purchase commitments (all short positions), and 0.5 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	$ (1,395,680)	$ 1,395,680
Purchased Gas	$ (5,985,069)	$ 5,985,069

Derivatives in SFAS 133 Fair Value Hedging Relationships		**Location of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income**	**Amount of Derivative Gain or (Loss) Recognized in the Consolidated Statement of Income for the Nine Months Ended June 30, 2009 (In Thousands)**	
Commodity Contracts	Energy Marketing segment[1]	Operating Revenues	$	(1,396)
Commodity Contracts	Energy Marketing segment[2]	Purchased Gas	$	2,221
Commodity Contracts	Energy Marketing segment[3]	Purchased Gas	$	(8,206)
			$	**(7,381)**

(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 storage withdrawal commitments of natural gas.

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 ten counterparties. The Company has $32.0 million of credit exposure with one counterparty. On average, the Company has $3.8 million of credit exposure per counterparty with the other nine counterparties (the Company has not received any collateral from these nine counterparties).

As of June 30, 2009, eight of the ten 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 (the lower of the S&P or Moody s Debt Rating), 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 and the Company s credit rating declined, then additional hedging collateral deposits would be required. At June 30, 2009, these credit-risk related contingency features would not have been triggered since the Company had assets of $57.6 million related to derivative financial instruments with the eight counterparties.

Item 1. Financial Statements (Cont.)

For its exchange traded futures contracts, which are in a liability position, the Company had paid $6.4 million in hedging collateral as of June 30, 2009. 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 (i.e. those positions that have been settled for cash) and margin requirements. (This is discussed in Note 1 under Hedging Collateral Deposits.)

Note 4 Income Taxes

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

	Nine Months Ended June 30,	
	2009	2008
Current Income Taxes		
Federal	$ 95,526	$ 92,384
State	25,528	23,388
Foreign		90
Deferred Income Taxes		
Federal	(67,051)	18,906
State	(18,443)	8,697
	35,560	143,465
Deferred Investment Tax Credit	(523)	(523)
Total Income Taxes	$ 35,037	$142,942
Presented as Follows:		
Other Income	$ (523)	$ (523)
Income Tax Expense	35,560	143,465
Total Income Taxes	$ 35,037	$142,942

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

	Nine Months Ended June 30,	
	2009	2008
U.S. Income Before Income Taxes	$108,747	$368,405
Income Tax Expense, Computed at Federal Statutory Rate of 35%	$ 38,061	$128,942
Increase (Reduction) in Taxes Resulting From:		
State Income Taxes	4,605	20,855
Domestic Production Activities Deduction	(1,790)	(1,878)

Miscellaneous	(5,839)	(4,977)
Total Income Taxes	$ 35,037	$142,942

Item 1. Financial Statements (Cont.)

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

	At June 30, 2009	At September 30, 2008
Deferred Tax Liabilities:		
Property, Plant and Equipment	$ 628,785	$ 673,313
Pension and Other Post-Retirement Benefit Costs SFAS 158	44,345	43,340
Unrealized Hedging Gains	25,564	14,936
Other	25,238	40,455
Total Deferred Tax Liabilities	723,932	772,044
Deferred Tax Assets:		
Pension and Other Post-Retirement Benefit Costs SFAS 158	(44,345)	(43,340)
Medicare Subsidy	(29,084)	(23,709)
Other	(94,132)	(68,752)
Total Deferred Tax Assets	(167,561)	(135,801)
Total Net Deferred Income Taxes	$ 556,371	$ 636,243
Presented as Follows:		
Net Deferred Tax Liability/(Asset) Current	$ (33,009)	$ 1,871
Net Deferred Tax Liability Non-Current	589,380	634,372
Total Net Deferred Income Taxes	$ 556,371	$ 636,243

Regulatory liabilities representing the reduction of previously recorded deferred income taxes with rate-regulated activities that are expected to be refundable to customers amounted to $18.5 million and $18.4 million at June 30, 2009 and September 30, 2008, respectively. Also, regulatory assets representing future amounts collectible from customers, corresponding to additional deferred income taxes not previously recorded because of prior ratemaking practices, amounted to $83.5 million and $82.5 million at June 30, 2009 and September 30, 2008, respectively.

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 2009 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 2006 and later years, IRS examinations for fiscal 2008 and prior years have been completed and the Company believes such years are effectively settled.

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.

As of June 30, 2009, the Company does not have any unrecognized tax benefits.

Note 5 Capitalization

Common Stock. During the nine months ended June 30, 2009, the Company issued 1,054,814 original issue shares of common stock as a result of stock option exercises. The Company also issued 7,000 original issue shares of common stock to the seven non-employee directors of the Company who receive compensation under the Company s Retainer Policy for Non-Employee Directors, as partial consideration for the directors services during the nine months ended June 30, 2009. Holders of stock options or

Item 1. Financial Statements (Cont.)
restricted stock will often tender shares of common stock to the Company for payment of option exercise prices and/or applicable withholding taxes. During the nine months ended June 30, 2009, 300,876 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.

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

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

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

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

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

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

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

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

Item 1. Financial Statements (Cont.)

Long-Term Debt. In April 2009, the Company issued $250.0 million of 8.75% notes due in May 2019. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $247.8 million. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of a change in control and a ratings downgrade to a rating below investment grade. The proceeds of this debt issuance were used for general corporate purposes, including to replenish cash that was used to pay the $100 million due at the maturity of the Company s 6.0% medium-term notes on March 1, 2009.

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.

As disclosed in Note H of the Company s 2008 Form 10-K, 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 $16.0 million.

At June 30, 2009, 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 $19.0 million to $23.2 million. The minimum estimated liability of $19.0 million, which includes the $16.0 million discussed above, has been recorded on the Consolidated Balance Sheet at June 30, 2009. The Company expects to recover its environmental clean-up costs from a combination of rate recovery and deferred insurance proceeds that are currently recorded as a regulatory liability on the Consolidated Balance Sheet.

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, or have a material adverse effect on the financial condition of the Company.

Item 1. Financial Statements (Cont.)

Note 7 Business Segment Information

In the Company s 2008 Form 10-K, the Company reported financial results for five business segments: Utility, Pipeline and Storage, Exploration and Production, Energy Marketing and Timber. The division of the Company s operations into the reported segments is based upon a combination of factors including differences in products and services, regulatory environment and geographic factors. During the quarter ended December 31, 2008, management made the decision to eliminate the Timber segment as a reportable segment based on the fact that the Timber operations do not meet any of the quantitative thresholds specified by SFAS 131. Furthermore, from a qualitative standpoint, management s focus has changed regarding the Timber operations. While the Timber segment will continue to harvest hardwood timber and process lumber products that are used in high-end furniture, cabinetry and flooring, management no longer considers the Timber operations to be integral to the overall operations of the Company. As a result of this change in focus and the fact that the Timber operations cannot be aggregated into one of the other four reportable business segments, the Timber operations have been included in the All Other category in the disclosures that follow. Prior year segment information shown below has been restated to reflect this change in presentation. In addition, refer to the Company s Form 8-K filed on March 17, 2009 that updated its historical business segment information contained in the Company s 2008 Form 10-K to reflect the change in reportable segments.

The data presented in the tables below reflect the reportable segments and reconciliations to consolidated amounts. As stated in the 2008 Form 10-K, the Company evaluates segment performance based on income before discontinued operations, extraordinary items and cumulative effects of changes in accounting (where 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, other than as noted above, nor in the basis of measuring segment profit or loss from those used in the Company s 2008 Form 10-K.

Item 1. Financial Statements (Cont.)

Quarter Ended June 30, 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	$158,310	$30,791	$97,619	$71,894	$358,614	$ 8,269	$ 228	$367,111
Intersegment Revenues	$ 2,940	$20,033	$	$	$ 22,973	$ 374	$(23,347)	$
Segment Profit: Net Income (Loss)	$ 5,396	$ 9,221	$27,083	$ 1,331	$ 43,031	$(1,086)	$ 959	$ 42,904

Nine Months Ended June 30, 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	$1,009,962	$105,904	$281,410	$350,445	$1,747,721	$30,523	$ 675	$1,778,919
Intersegment Revenues	$ 13,339	$ 62,026	$	$	$ 75,365	$ 3,890	$(79,255)	$
Segment Profit: Net Income (Loss)	$ 60,303	$ 41,582	$ (38,366)	$ 7,509	$ 71,028	$ (46)	$ 2,728	$ 73,710

Quarter Ended June 30, 2008 (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	$217,339	$32,054	$126,154	$162,129	$537,676	$10,509	$ 197	$548,382
Intersegment Revenues	$ 3,154	$20,131	$	$	$ 23,285	$ 4,439	$(27,724)	$
Segment Profit: Net Income (Loss)	$ 7,848	$12,534	$ 39,791	$ 478	$ 60,651	$ (960)	$ 164	$ 59,855

Nine Months Ended June 30, 2008 (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	$1,067,194	$101,871	$348,829	$440,111	$1,958,005	$44,002	$ 496	$2,002,503
Intersegment Revenues	$ 13,567	$ 61,340	$	$	$ 74,907	$10,251	$(85,158)	$
Segment Profit: Net Income (Loss)	$ 62,228	$ 40,931	$108,385	$ 7,079	$ 218,623	$ 7,351	$ (511)	$ 225,463

At June 30, 2009 (Thousands)

	Utility	Pipeline And Storage	Exploration and Production	Energy Marketing	Total Reportable Segments	All Other	Corporate and Intersegment Eliminations	Total Consolidated
Segment Assets	$1,775,953	$1,003,362	$1,257,131	$61,653	$4,098,099	$208,069	$49,134	$4,355,302

Item 1. Financial Statements (Cont.)

Note 8 Intangible Assets

The components of the Company s intangible assets were as follows (in thousands):

	At June 30, 2009			At September 30, 2008
	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Net Carrying Amount
Intangible Assets Subject to Amortization:				
Long-Term Transportation Contracts	$ 4,701	$ (2,531)	$ 2,170	$ 2,522
Long-Term Gas Purchase Contracts	31,864	(9,407)	22,457	23,652
	$ 36,565	$ (11,938)	$ 24,627	$ 26,174

Aggregate Amortization Expense:	
(Thousands)	
Three Months Ended June 30, 2009	$ 497
Three Months Ended June 30, 2008	$ 666
Nine Months Ended June 30, 2009	$ 1,547
Nine Months Ended June 30, 2008	$ 1,997

In October 2008, the Company completed the amortization of intangible assets related to two long-term transportation contracts. As such, the gross carrying amount of intangible assets subject to amortization was reduced from $8.6 million at September 30, 2008 to $4.7 million at June 30, 2009. Aside from this change, the only activity with regard to intangible assets subject to amortization was amortization expense as shown in the table above. Amortization expense for the long-term transportation contracts is estimated to be $0.1 million for the remainder of 2009 and $0.4 million annually for 2010, 2011, 2012 and 2013. Amortization expense for the long-term gas purchase contracts is estimated to be $0.4 million for the remainder of 2009 and $1.6 million annually for 2010, 2011, 2012 and 2013.

Note 9 Retirement Plan and Other Post-Retirement Benefits

Components of Net Periodic Benefit Cost (in thousands):

Three months ended June 30,

	Retirement Plan		Other Post-Retirement Benefits	
	2009	2008	2009	2008
Service Cost	$ 2,728	$ 3,149	$ 950	$ 1,276
Interest Cost	11,709	11,237	6,875	6,770
Expected Return on Plan Assets	(14,489)	(13,750)	(7,904)	(8,428)
Amortization of Prior Service Cost	183	202	(268)	1
Amortization of Transition Amount			566	1,782
Amortization of Losses	1,419	2,766	2,318	732
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) (1)	2,255	783	3,878	4,354

Net Periodic Benefit Cost	$ 3,805	$ 4,387	$ 6,415	$ 6,487

Item 1. <u>Financial Statements (Cont.)</u>
Nine months ended June 30,

	Retirement Plan		Other Post-Retirement Benefits	
	2009	2008	2009	2008
Service Cost	$ 8,185	$ 9,448	$ 2,851	$ 3,828
Interest Cost	35,127	33,712	20,624	20,311
Expected Return on Plan Assets	(43,468)	(41,250)	(23,711)	(25,286)
Amortization of Prior Service Cost	548	606	(805)	3
Amortization of Transition Amount			1,699	5,346
Amortization of Losses	4,257	8,298	6,953	2,195
Net Amortization and Deferral for Regulatory Purposes (Including Volumetric Adjustments) (1)	12,853	7,597	16,232	20,028
Net Periodic Benefit Cost	$ 17,502	$ 18,411	$ 23,843	$ 26,425

(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.

As indicated under New Accounting Pronouncements in Note 1 Summary of Significant Accounting Policies, in accordance with the measurement date provisions of SFAS 158 that specifies that a plan s assets and obligations that determine its funded status be measured as of the end of the Company s fiscal year, the Company will be recording fifteen months of pension and other post-retirement benefit costs during fiscal 2009. As allowed by SFAS 158, these costs have been calculated using June 30, 2008 measurement date data. Three of those months pertain to the period of

July 1, 2008 to September 30, 2008. The pension and other post-retirement benefit costs for that period amounted to $3.8 million and have been recorded by the Company during the nine months ended June 30, 2009 as a $3.4 million increase to Other Regulatory Assets in the Company s Utility and Pipeline and Storage segments and a $0.4 million ($0.2 million after tax) adjustment to earnings reinvested in the business. In addition, for the Company s non-qualified pension plan, benefit costs of $1.3 million have been recorded by the Company during the nine months ended June 30, 2009 as a $0.4 million increase to Other Regulatory Assets in the Company s Utility segment and a $0.9 million ($0.6 million after tax) adjustment to earnings reinvested in the business. The requirement to measure the plan assets and benefit obligations as of the Company s fiscal year-end date will be fully adopted by the Company by the end of fiscal 2009.

Employer Contributions. During the nine months ended June 30, 2009, the Company contributed $16.0 million to its retirement plan and $21.5 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2009, the Company does not expect to contribute to its retirement plan. As a result of the recent downturn in the stock markets and general economic conditions, it is expected that the Company will fund in the range of $20 million to $40 million to the retirement plan subsequent to fiscal 2009. In the remainder of 2009, the Company expects to contribute approximately $5.0 million to its VEBA trusts and 401(h) accounts.

Note 10 Subsequent Events

In accordance with SFAS 165, Subsequent Events, the Company has evaluated subsequent events through August 7, 2009, which represents the filing date of this Form 10-Q with the SEC, in order to ensure that this Form 10-Q includes appropriate disclosure of events both recognized in the financial statements as of June 30, 2009, and events which occurred subsequent to June 30, 2009 but were not recognized in the financial statements. As of August 7, 2009, there were no subsequent events which required recognition or disclosure other than as set forth below.

Item 1. Financial Statements (Concl.)

On July 20, 2009, the Company announced that in its Exploration and Production segment, Seneca had purchased Ivanhoe Energy s United States oil and gas operations for approximately $39.2 million, of which $2 million was placed in escrow as a deposit for the acquisition as of June 30, 2009. As of June 2009, these assets produced approximately 645 (595 net) barrels per day of oil in California and Texas. The purchase also included certain exploration acreage in California. This acquisition adds to the Company s existing oil producing assets in the Midway Sunset Field in California.

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

OVERVIEW

The Company is a diversified energy company consisting of four reportable business segments. For the quarter ended June 30, 2009 compared to the quarter ended June 30, 2008, the Company experienced a decrease in earnings of $17.0 million, primarily due to lower earnings in the Exploration and Production segment. For the nine months ended June 30, 2009 compared to the nine months ended June 30, 2008, the Company experienced a decrease in earnings of $151.8 million. The earnings decrease for the nine-month period was driven largely by an impairment charge of $182.8 million ($108.2 million after tax) recorded in the Exploration and Production segment. 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. Such costs are subject to a quarterly ceiling test prescribed by SEC Regulation S-X Rule 4-10 that determines a limit, or ceiling, on the amount of property acquisition, exploration and development costs that can be capitalized. At December 31, 2008, due to significant declines in crude oil and natural gas commodity prices (Cushing, Oklahoma West Texas Intermediate oil reported spot price of $44.60 per Bbl at December 31, 2008 versus a reported price of $100.70 per Bbl at September 30, 2008; Henry Hub natural gas reported spot price of $5.63 per MMBtu at December 31, 2008 versus a reported price of $7.12 per MMBtu at September 30, 2008), the book value of the Company s oil and gas properties exceeded the ceiling, resulting in the impairment charge mentioned above. (Note Because actual pricing of the Company s various producing properties varies depending on their location, the actual various prices received for such production is utilized to calculate the ceiling, rather than the Cushing oil and Henry Hub prices, which are only indicative of current prices.) At June 30, 2009, the quoted Cushing, Oklahoma spot price for West Texas Intermediate oil was $69.82 per Bbl ($49.64 per Bbl at March 31, 2009) and the quoted spot price for natural gas was $3.88 per MMBtu ($3.63 per MMBtu at March 31, 2009). At June 30, 2009, the ceiling exceeded the book value of the Company s oil and gas properties by approximately $247 million (and approximately $37 million at March 31, 2009). If natural gas prices used in the ceiling test calculation at June 30, 2009 had been $1 per MMBtu lower, the ceiling would have exceeded the book value of the Company s oil and gas properties by approximately $197 million. If crude oil prices used in the ceiling test calculation at June 30, 2009 had been $5 per Bbl lower, the ceiling would have exceeded the book value of the Company s oil and gas properties by approximately $196 million. If both natural gas and crude oil prices used in the ceiling test calculation at June 30, 2009 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 $146 million. These calculated amounts are based solely on price changes and do not take into account any other changes to the ceiling test calculation.

Despite the decrease in earnings discussed above, the Company s balance sheet consisted of a capitalization structure of 57% equity and 43% debt at June 30, 2009. With its April 2009 issuance of $250.0 million of 8.75% notes due in May 2019, management believes that it has enhanced its liquidity position at a time when there is still uncertainty in the credit markets. In addition to the proceeds from this debt issuance, the Company has been able to borrow short-term funds under its credit lines and through the commercial paper market to fund working capital needs throughout the first nine months of 2009. At June 30, 2009, the Company did not have any short-term borrowings outstanding. However, the Company continues to maintain a number of individual uncommitted or discretionary lines of credit with financial institutions for general corporate purposes. These credit lines, which aggregate to $420.0 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 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, 2010.

In the Company s Exploration and Production segment, there continues to be a strong focus on exploring and developing the nearly one million acres of oil and gas rights in the Appalachian region, including the 720,000 acres in the Marcellus Shale. However, the Company continues to look for growth opportunities in other areas as well. In July 2009, the Exploration and Production segment purchased Ivanhoe Energy s United States oil and gas operations for approximately $39.2 million. This purchase complements this segment s existing oil producing assets in the

Midway Sunset Field in California. This acquisition was funded with cash on hand.

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

The Company, through Midstream Corporation, is pursuing the development of gathering systems in Tioga County and Lycoming County in Pennsylvania. The project, called the Midstream Covington Gathering Project, is to be constructed in three phases, with the first phase under construction and anticipated to be placed in service by the fall of 2009. The second phase is anticipated to be placed in service by the fall of 2010. The schedule for the final phase is being developed. When all three phases are complete, the system will consist of approximately 30 miles of gathering system pipeline at a cost of approximately $25 million to $30 million. Phase I is estimated to cost approximately $15 million. As of June 30, 2009, the Company has spent approximately $2.8 million in costs on Phase I and Phase II related to this project. The Company has funded these costs with cash on hand and anticipates that future costs will be funded with cash on hand as well.

CRITICAL ACCOUNTING ESTIMATES

For a complete discussion of critical accounting estimates, refer to Critical Accounting Estimates in Item 7 of the Company s 2008 Form 10-K and Item 2 of the Company s December 31, 2008 and March 31, 2009 Form 10-Qs. There have been no material changes to those disclosures other than as set forth below. The information presented below updates and should be read in conjunction with the critical accounting estimates in those documents.

Oil and Gas Exploration and Development Costs. The Company, in its Exploration and Production segment, follows the full cost method of accounting for determining the book value of its oil and natural gas properties. In accordance with this methodology, the Company is required to perform a quarterly ceiling test. Under the ceiling test, the present value of future revenues from the Company s oil and gas reserves based on current market prices (the ceiling) is compared with the book value of those reserves at the balance sheet date. If the book value of the reserves in any country exceeds the ceiling, a non-cash charge must be recorded to reduce the book value of the reserves to the calculated ceiling. As disclosed in the Company s 2008 Form 10-K, at September 30, 2008, the ceiling exceeded the book value of the Company s oil and gas properties by approximately $500 million. Because of declines in commodity prices since September 30, 2008, the book value of the Company s oil and gas properties exceeded the ceiling at December 31, 2008. The quoted Cushing, Oklahoma spot price for West Texas Intermediate oil had declined from a reported price of $100.70 per Bbl at September 30, 2008 to a reported price of $44.60 per Bbl at December 31, 2008. The quoted Henry Hub spot price for natural gas had declined from a reported price of $7.12 per MMBtu at September 30, 2008 to a reported price of $5.63 per MMBtu at December 31, 2008. Consequently, the Company recorded an impairment charge of $182.8 million ($108.2 million after-tax) during the quarter ended December 31, 2008. (Note Because actual pricing of the Company s various producing properties varies depending on their location, the actual various prices received for such production is utilized to calculate the ceiling, rather than the Cushing oil and Henry Hub prices, which are only indicative of current prices.) At June 30, 2009, the quoted Cushing, Oklahoma spot price for West Texas Intermediate oil was $69.82 per Bbl ($49.64 per Bbl at March 31, 2009) and the quoted spot price for natural gas was $3.88 per MMBtu ($3.63 per MMBtu at March 31, 2009). At June 30, 2009, the ceiling exceeded the book value of the Company s oil and gas properties by approximately $247 million (and approximately $37 million at March 31, 2009). If natural gas prices used in the ceiling test calculation at June 30, 2009 had been $1 per MMBtu lower, the ceiling would have exceeded the book value of the Company s oil and gas properties by approximately $197 million. If crude oil prices used in the ceiling test calculation at June 30, 2009 had been $5 per Bbl lower, the ceiling would have exceeded the book value of the Company s oil and gas properties by approximately $196 million. If both natural gas and crude oil prices used in the ceiling test calculation at June 30, 2009 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 $146 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 2008 Form 10-K.

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

RESULTS OF OPERATIONS

Earnings

The Company s earnings were $42.9 million for the quarter ended June 30, 2009 compared to earnings of $59.9 million for the quarter ended June 30, 2008. The decrease in earnings of $17.0 million is primarily the result of lower earnings in the Exploration and Production segment. The Utility and Pipeline and Storage segments, as well as the All Other category also contributed to the decrease in earnings. Higher earnings in the Energy Marketing segment and the Corporate category slightly offset these decreases.

The Company s earnings were $73.7 million for the nine months ended June 30, 2009 compared to earnings of $225.5 million for the nine months ended June 30, 2008. The decrease in earnings of $151.8 million is primarily the result of lower earnings in the Exploration and Production segment. The Utility segment and the All Other category also contributed to the decrease in earnings. Higher earnings in the Pipeline and Storage and Energy Marketing segments, as well as the Corporate category, slightly offset these decreases. The Company s earnings for the nine months ended June 30, 2009 include a non-cash $182.8 million impairment charge ($108.2 million after tax) recorded during the quarter ended December 31, 2008 for the Exploration and Production segment s oil and gas producing properties.

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

Earnings (Loss) by Segment

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2009	2008	Increase/ (Decrease)	2009	2008	Increase/ (Decrease)
Utility	$ 5,396	$ 7,848	$ (2,452)	$ 60,303	$ 62,228	$ (1,925)
Pipeline and Storage	9,221	12,534	(3,313)	41,582	40,931	651
Exploration and Production	27,083	39,791	(12,708)	(38,366)	108,385	(146,751)
Energy Marketing	1,331	478	853	7,509	7,079	430
Total Reportable Segments	43,031	60,651	(17,620)	71,028	218,623	(147,595)
All Other	(1,086)	(960)	(126)	(46)	7,351	(7,397)
Corporate	959	164	795	2,728	(511)	3,239
Total Consolidated	$ 42,904	$ 59,855	$ (16,951)	$ 73,710	$ 225,463	$ (151,753)

Utility

Utility Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2009	2008	Increase/ (Decrease)	2009	2008	Increase/ (Decrease)
Retail Sales Revenues:						
Residential	$ 119,746	$ 153,058	$ (33,312)	$ 786,170	$ 793,124	$ (6,954)
Commercial	15,627	20,459	(4,832)	122,197	124,582	(2,385)
Industrial	808	1,178	(370)	6,835	6,754	81

	136,181	174,695	(38,514)	915,202	924,460	(9,258)
Transportation	22,012	21,584	428	94,951	97,345	(2,394)
Off-System Sales		20,540	(20,540)	3,740	48,606	(44,866)
Other	3,057	3,674	(617)	9,408	10,350	(942)
	$ 161,250	$ 220,493	$ (59,243)	$ 1,023,301	$ 1,080,761	$ (57,460)

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

	Three Months Ended June 30,			Nine Months Ended June 30,		
(MMcf)	2009	2008	Decrease	2009	2008	Increase/ (Decrease)
Retail Sales:						
Residential	8,468	8,618	(150)	55,001	53,881	1,120
Commercial	1,221	1,334	(113)	8,984	9,197	(213)
Industrial	55	77	(22)	499	524	(25)
	9,744	10,029	(285)	64,484	63,602	882
Transportation	10,747	12,086	(1,339)	52,476	55,966	(3,490)
Off-System Sales		1,711	(1,711)	513	4,790	(4,277)
	20,491	23,826	(3,335)	117,473	124,358	(6,885)

Degree Days

				Percent Colder (Warmer) Than	
	Normal	2009	2008	Normal	Prior Year
Three Months Ended June 30					
Buffalo	927	854	817	(7.9)	4.5
Erie	885	821	762	(7.2)	7.7
Nine Months Ended June 30					
Buffalo	6,514	6,558	6,175	0.7	6.2
Erie	6,108	6,064	5,737	(0.7)	5.7

2009 Compared with 2008

Operating revenues for the Utility segment decreased $59.2 million for the quarter ended June 30, 2009 as compared with the quarter ended June 30, 2008. The decrease for the quarter is primarily attributable to a $38.5 million decrease in retail sales revenue and a $20.5 million decrease in off-system sales revenue. The $38.5 million decrease in retail gas sales revenues was primarily a function of lower gas costs (subject to certain timing variations, gas costs are recovered dollar for dollar in revenues). The decrease in off-system sales revenue stems from Order No. 717 (Final Rule), which was issued by the FERC on October 16, 2008. The Final Rule seemingly holds that a local distribution company making off-system sales on unaffiliated pipelines would engage in marketing that would require compliance with the FERC s standards of conduct. Accordingly, pending clarification of this issue from the FERC, as of November 1, 2008, Distribution Corporation ceased off-system sales activities.

Operating revenues for the Utility segment decreased $57.5 million for the nine months ended June 30, 2009 as compared with the nine months ended June 30, 2008. This decrease largely resulted from a $44.9 million decrease in off-system sales revenue, which is discussed above, a $9.3 million decrease in retail sales revenue and a $2.4 million decrease in transportation revenues. The decrease in retail gas sales revenues for the Utility segment was largely a function of lower gas costs (subject to certain timing variations, gas costs are recovered dollar for dollar in revenues) partially offset by higher residential retail sales volumes, as shown in the table above. The volume increase was primarily the result of weather that was 6.2 percent colder than the prior year in the New York jurisdiction and 5.7 percent colder than the prior year in the Pennsylvania jurisdiction. The decrease in transportation revenues was primarily attributable to conservation efforts and the poor economy.

In the New York jurisdiction, the NYPSC issued an order providing for an annual rate increase of $1.8 million beginning December 28, 2007. As part of this rate order, a rate design change was adopted that shifts a greater amount of cost recovery into the minimum bill amount, thus spreading the recovery of such costs more evenly throughout the year. As a result of this rate order, retail and transportation

Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations (Cont.)
revenues for the nine months ended June 30, 2009 were $2.2 million lower than revenues for the nine months ended June 30, 2008. There was no impact to revenues when comparing the quarters ended June 30, 2009 and June 30, 2008.

The Utility segment s earnings for the quarter ended June 30, 2009 were $5.4 million, a decrease of $2.4 million compared to earnings of $7.8 million for the quarter ended June 30, 2008. In the New York jurisdiction, earnings decreased by $1.1 million. The decrease was largely due to higher interest expense ($1.5 million) partially offset by lower operating costs ($0.4 million). The increase in interest expense stems from the Company s April 2009 debt issuance. This debt was issued at a significantly higher interest rate than the interest rates on existing debt at the time of issuance. In the Pennsylvania jurisdiction, earnings decreased by $1.3 million. The decrease was largely due to higher interest expense ($0.4 million) and lower usage per account ($0.4 million). The phrase usage per account refers to the average gas consumption per customer account after factoring out any impact that weather may have had on consumption. As with the New York jurisdiction, the increase in interest expense in the Pennsylvania jurisdiction is attributable to the Company s April 2009 debt issuance.

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 jurisdiction. For both the quarter ended June 30, 2009 and June 30, 2008, the WNC preserved earnings of approximately $0.4 million, as weather was warmer than normal for those periods.

The Utility segment s earnings for the nine months ended June 30, 2009 were $60.3 million, a decrease of $1.9 million when compared with earnings of $62.2 million for the nine months ended June 30, 2008. In the New York jurisdiction, earnings decreased $0.5 million. The earnings impact of the December 28, 2007 rate order discussed above ($1.4 million), higher interest expense ($1.1 million) and regulatory true-up adjustments ($0.5 million) were the main factors in the earnings decrease. These factors were offset by a $3.0 million decrease in operating costs (primarily due to a decrease in other post-retirement benefit costs as well as a decrease in health insurance and prescription drug costs). The reason for the increase in interest costs is attributable to the April 2009 debt issuance, as discussed above. In the Pennsylvania jurisdiction, earnings decreased $1.4 million. The negative earnings impact associated with lower usage per account ($1.9 million), higher income tax expense ($1.4 million) and higher operating costs of $1.3 million (primarily bad debt expense due to the possible impact current economic conditions may have on customers) was largely offset by the positive earnings impact of colder weather ($2.0 million) and lower interest expense ($0.5 million).

For the nine months ended June 30, 2009, the WNC reduced earnings by approximately $0.2 million, as the weather was colder than normal. For the nine months ended June 30, 2008, the WNC preserved earnings of approximately $2.5 million, as the weather was warmer than normal.

Pipeline and Storage

Pipeline and Storage Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2009	2008	Increase/ (Decrease)	2009	2008	Increase/ (Decrease)
Firm Transportation	$ 32,894	$ 29,020	$ 3,874	$ 105,931	$ 93,427	$ 12,504
Interruptible Transportation	635	1,151	(516)	2,862	3,237	(375)
	33,529	30,171	3,358	108,793	96,664	12,129
Firm Storage Service	16,648	16,754	(106)	50,101	50,311	(210)
Interruptible Storage Service	4		4	18	14	4
Other	643	5,260	(4,617)	9,018	16,222	(7,204)

	$ 50,824	$ 52,185	$ (1,361)	$ 167,930	$ 163,211	$ 4,719

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

	Three Months Ended June 30,			Nine Months Ended June 30,		
(MMcf)	2009	2008	Decrease	2009	2008	Increase/ (Decrease)
Firm Transportation	60,798	68,263	(7,465)	305,001	283,104	21,897
Interruptible Transportation	501	1,540	(1,039)	3,558	3,844	(286)
	61,299	69,803	(8,504)	308,559	286,948	21,611

2009 Compared with 2008

Operating revenues for the Pipeline and Storage segment decreased $1.4 million for the quarter ended June 30, 2009 as compared with the quarter ended June 30, 2008. The decrease was primarily due to decreased efficiency gas revenues ($3.9 million) reported as part of other revenues in the table above. This decrease was primarily due to lower gas prices and lower transportation volumes during the quarter ended June 30, 2009 as compared with the quarter ended June 30, 2008. Under Supply Corporation s tariff with suppliers, Supply Corporation is allowed to retain a set percentage of shipper-supplied gas to cover compressor fuel costs and other operational purposes. To the extent that Supply Corporation does not need all of the gas to cover such operational needs, it is allowed to keep the excess gas as inventory. That inventory is later sold to customers. The excess gas that is retained as inventory represents efficiency gas revenue to Supply Corporation. The decrease in efficiency gas revenues was partially offset by an increase in transportation revenues ($3.4 million) due to higher revenues from the Empire Connector, which was placed in service in December 2008, combined with higher reservation, commodity, and surcharge revenues associated with new contracts for transportation service. While transportation volumes decreased during the quarter, volume fluctuations generally do not have a significant impact on revenues as a result of the straight fixed-variable rate design used by both Supply Corporation and Empire.

Operating revenues for the nine months ended June 30, 2009 increased $4.7 million as compared with the nine months ended June 30, 2008. The increase was primarily due to a $12.1 million increase in transportation revenue primarily due to higher revenues from the Empire Connector and new contracts for transportation service. Partially offsetting this increase, efficiency gas revenues decreased $6.7 million due primarily to lower gas prices in the nine months ended June 30, 2009 as compared with the nine months ended June 30, 2008.

The Pipeline and Storage segment s earnings for the quarter ended June 30, 2009 were $9.2 million, a decrease of $3.3 million when compared to earnings of $12.5 million for the quarter ended June 30, 2008. The earnings decrease was primarily due to lower efficiency gas revenues ($2.5 million), as discussed above. Higher interest expense ($1.4 million) and a decrease in the allowance for funds used during construction ($0.9 million) also contributed to the earnings decrease. The decreases were partially offset by the earnings impact associated with higher transportation revenues ($2.2 million). The increase in interest expense can be attributed to higher debt balances and a higher average interest rate on borrowings. The increase in the average interest rate stems from the Company s April 2009 debt issuance. The decrease in the allowance for funds used during construction can be attributed to the completion of the Empire Connector in December 2008.

The Pipeline and Storage segment s earnings for the nine months ended June 30, 2009 were $41.6 million, an increase of $0.7 million when compared to earnings of $40.9 million for the nine months ended June 30, 2008. The increase was primarily due to the earnings impact associated with an increase in transportation revenues ($7.9 million), as discussed above. In addition, increased earnings resulted from an increase in the allowance for funds used during construction ($0.7 million) and higher interest income ($0.1 million). The increase in the allowance for funds used during construction reflects the fact that construction work in progress balances for the Empire Connector were significantly higher during the quarter ended December 31, 2008 than they were during the nine months ended

June 30, 2008. While construction of the Empire Connector began in September 2007, winter weather limited significant construction until the spring and summer of 2008. These factors, which increased earnings, were largely

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

offset by a decrease in efficiency gas revenues ($4.4 million), higher interest expense ($3.1 million), and higher depreciation expense ($1.2 million). The increase in interest expense can be attributed to higher debt balances and a higher average interest rate on borrowings. The increase in the average interest rate stems from the Company s April 2009 debt issuance. The increase in depreciation expense can be attributed primarily to a revision of accumulated depreciation combined with the increased depreciation associated with placing the Empire Connector in service in December 2008.

Exploration and Production

Exploration and Production Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2009	2008	Increase/ (Decrease)	2009	2008	Increase/ (Decrease)
Gas (after Hedging)	$ 38,450	$ 56,591	$ (18,141)	$ 118,345	$ 155,793	$ (37,448)
Oil (after Hedging)	56,690	66,695	(10,005)	156,340	185,650	(29,310)
Gas Processing Plant	5,380	13,566	(8,186)	18,785	35,674	(16,889)
Other	270	(291)	561	717	(3,174)	3,891
Intrasegment Elimination (1)	(3,171)	(10,407)	7,236	(12,777)	(25,114)	12,337
	$ 97,619	$ 126,154	$ (28,535)	$ 281,410	$ 348,829	$ (67,419)

(1) Represents the elimination of certain West Coast gas production 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.

	Three Months Ended June 30,	Nine Months Ended June 30,

Production Volumes	2009	2008	Increase/ (Decrease)	2009	2008	Increase/ (Decrease)
Gas Production *(MMcf)*						
Gulf Coast	3,307	3,019	288	7,118	8,868	(1,750)
West Coast	1,014	1,007	7	3,063	3,010	53
Appalachia	2,155	1,793	362	6,065	5,538	527
Total Production	6,476	5,819	657	16,246	17,416	(1,170)
Oil Production *(Mbbl)*						
Gulf Coast	176	124	52	470	409	61
West Coast	654	598	56	1,984	1,825	159
Appalachia	14	23	(9)	41	88	(47)
Total Production	844	745	99	2,495	2,322	173

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Average Prices

	Three Months Ended June 30, 2009	2008	Decrease	Nine Months Ended June 30, 2009	2008	Decrease
Average Gas Price/Mcf						
Gulf Coast	$ 3.95	$ 12.17	$ (8.22)	$ 4.90	$ 9.66	$ (4.76)
West Coast	$ 3.04	$ 10.61	$ (7.57)	$ 4.10	$ 8.43	$ (4.33)
Appalachia	$ 4.11	$ 11.53	$ (7.42)	$ 6.06	$ 9.25	$ (3.19)
Weighted Average	$ 3.86	$ 11.71	$ (7.85)	$ 5.18	$ 9.32	$ (4.14)
Weighted Average After Hedging	$ 5.94	$ 9.73	$ (3.79)	$ 7.28	$ 8.95	$ (1.67)
Average Oil Price/Bbl						
Gulf Coast	$ 56.29	$ 124.43	$ (68.14)	$ 50.64	$ 103.46	$ (52.82)
West Coast	$ 55.77	$ 114.35	$ (58.58)	$ 46.84	$ 94.64	$ (47.80)
Appalachia	$ 48.93	$ 114.99	$ (66.06)	$ 54.90	$ 94.18	$ (39.28)
Weighted Average	$ 55.77	$ 116.05	$ (60.28)	$ 47.69	$ 96.17	$ (48.48)
Weighted Average After Hedging	$ 67.19	$ 89.55	$ (22.36)	$ 62.67	$ 79.97	$ (17.30)

2009 Compared with 2008

Operating revenues for the Exploration and Production segment decreased $28.5 million for the quarter ended June 30, 2009 as compared with the quarter ended June 30, 2008. Gas production revenue after hedging decreased $18.1 million. This decrease is due to a decrease in the weighted average price of gas after hedging ($3.79 per Mcf), partially offset by an increase in gas production of 657 MMcf. The increase in gas production occurred partially in this segment s Appalachian region (362 MMcf) as a result of additional wells drilled throughout fiscal 2008 that came on line in 2009. The Gulf Coast region also experienced an increase in gas production (288 MMcf). Production from a new field (Cyclops) that started producing at the end of March 2009 was responsible for the increase, partly offset by declines in production from some existing fields, quarter to quarter. Oil production revenue after hedging decreased $10.0 million due to a $22.36 per Bbl decline in weighted average prices of oil after hedging. This decrease was partially offset by an increase in production in the Gulf Coast and West Coast regions of this segment. The increase in crude oil production in the Gulf Coast region of 52 Mbbl is due to production from a new field in the High Island area. In the West Coast region, increased production at the Midway Sunset field is responsible for the increase in crude oil production of 56 Mbbl in this region.

Operating revenues for the Exploration and Production segment decreased $67.4 million for the nine months ended June 30, 2009 as compared with the nine months ended June 30, 2008. Gas production revenue after hedging decreased $37.4 million due to a decline in the weighted average price of gas after hedging ($1.67 per Mcf) as well as a decrease in gas production of 1,170 MMcf. The decrease in gas production occurred in the Gulf Coast region (1,750 MMcf) as a result of lingering shut-ins caused by Hurricane Ike in September 2008. While Seneca s properties sustained only superficial damage from the hurricanes, two significant producing properties were shut-in for a significant portion of the current fiscal year due to repair work on third party pipelines and onshore processing facilities. One of the properties was back on line by March 31, 2009 and the other property was back on line by the end of April 2009. Partly offsetting the decrease in gas production in the Gulf Coast region was an increase in gas production in the Appalachian region of 527 MMcf as a result of additional wells drilled throughout fiscal 2008 that came on line in 2009. Oil production revenue after hedging decreased $29.3 million due primarily to a $17.30 per Bbl decrease in weighted average prices of oil after hedging, partially offset by an increase in production in the West Coast and Gulf Coast regions.

The Exploration and Production segment s earnings for the quarter ended June 30, 2009 were $27.1 million, a decrease of $12.7 million when compared with earnings of $39.8 million for the quarter ended June 30, 2008. Lower natural gas prices and crude oil prices decreased earnings by $15.9 million and $12.3 million, respectively, while higher crude oil production and natural gas production increased earnings by $5.8 million and $4.2 million, respectively. Lower interest income of $1.3 million due to lower

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interest rates also contributed to the decline in earnings. Lower lease operating expenses of $2.8 million, lower interest expense of $1.7 million, and the earnings impact associated with a lower effective tax rate ($2.4 million) somewhat offset the decline in earnings. The decrease in lease operating expenses is primarily due to a reduction in steam fuel costs in the West Coast region and a decline in marine fuel costs and production taxes as well as lower expenses due to the sale of five properties during fiscal 2009, all in the Gulf Coast region. The decrease in interest expense is primarily due to a lower average amount of debt outstanding.

The Exploration and Production segment s loss for the nine months ended June 30, 2009 was $38.4 million, compared with earnings of $108.4 million for the nine months ended June 30, 2008, a decrease of $146.8 million. The decrease in earnings is primarily the result of an impairment charge of $108.2 million, as discussed above. In addition, lower crude oil prices, lower natural gas prices and lower natural gas production contributed to the decrease in earnings by $28.0 million, $17.5 million and $6.8 million, respectively, while higher crude oil production increased earnings by $9.0 million. Higher operating costs of $3.0 million and lower interest income of $4.6 million also contributed to the decrease in earnings. The increase in operating costs is primarily due to an increase in bad debt expense as a result of a customer s bankruptcy filing, and higher personnel costs in the Appalachian and Gulf Coast regions. The decline in interest income is due to lower interest rates and lower temporary cash investment balances. Slightly offsetting these earnings decreases were lower interest expense ($4.7 million), lower lease operating expenses ($3.1 million), lower depletion expense ($1.9 million) and lower state income tax expense ($3.2 million). The decline in interest expense is primarily due to a lower average amount of debt outstanding. The decrease in lease operating expenses is primarily due to a reduction in steam fuel costs in the West Coast region and a decline in well servicing workover expenses and production taxes in the Gulf Coast region. The decrease in depletion is primarily due to a lower full cost pool balance after the impairment charge taken during the quarter ended December 31, 2008.

Energy Marketing

Energy Marketing Operating Revenues

	Three Months Ended June 30,			Nine Months Ended June 30,		
(Thousands)	2009	2008	Increase/ (Decrease)	2009	2008	Increase/ (Decrease)
Natural Gas (after Hedging)	$ 71,870	$ 162,127	$ (90,257)	$ 350,331	$ 440,123	$ (89,792)
Other	24	2	22	114	(12)	126
	$ 71,894	$ 162,129	$ (90,235)	$ 350,445	$ 440,111	$ (89,666)

Energy Marketing Volumes

	Three Months Ended June 30,			Nine Months Ended June 30,		
	2009	2008	Decrease	2009	2008	Increase
Natural Gas (MMcf)	14,634	14,641	(7)	50,459	47,189	3,270

2009 Compared with 2008

Operating revenues for the Energy Marketing segment decreased $90.2 million and $89.7 million, respectively, for the quarter and nine months ended June 30, 2009 as compared with the quarter and nine months ended June 30, 2008. The decrease for both the quarter and nine months ended June 30, 2009 is primarily due to lower gas sales revenue due to a lower average price of natural gas that was recovered through revenues. For the nine months ended June 30, 2009 as compared to the nine months ended June 30, 2008, this decline was somewhat offset by an increase in volumes sold. The increase in volumes is largely attributable to colder weather as well as sales transactions undertaken to offset certain

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basis risk that the Energy Marketing segment was exposed to under certain commodity purchase contracts. These offsetting transactions had the effect of increasing revenue and volumes sold with minimal impact to earnings.

Earnings in the Energy Marketing segment increased $0.9 million and $0.4 million, respectively, for the quarter and nine months ended June 30, 2009 as compared with the quarter and nine months ended June 30, 2008. For the quarter ended June 30, 2009, lower operating costs of $0.6 million, primarily due to a decrease in bad debt expense, as well as higher margins of $0.4 million, are responsible for the increase in earnings. The increase in margins was primarily driven by lower pipeline transportation fuel costs due to lower natural gas commodity prices. For the nine months ended June 30, 2009, higher margins of $0.6 million combined with lower operating costs of $0.4 million (primarily due to a decline in bad debt expense) are responsible for the increase in earnings. These increases were partially offset by higher income tax expense of $0.4 million for the nine months ended June 30, 2009 as compared to the nine months ended June 30, 2008.

Corporate and All Other

2009 Compared with 2008

Corporate and All Other recorded losses of $0.1 million and $0.8 million for the quarters ended June 30, 2009 and June 30, 2008, respectively. The decrease in the loss period over period was largely due to lower operating costs ($1.1 million). In 2008, the proxy contest with New Mountain Vantage GP, L.L.C. led to an increase in operating costs, which did not recur in 2009. In addition, lower income tax expense ($0.8 million), higher margins from log and lumber sales ($0.3 million), and higher interest income ($0.3 million) contributed to the increase in earnings. These were partially offset by higher interest expense ($0.8 million) due to higher borrowings at a higher interest rate (mostly due to the $250 million of 8.75% notes that were issued in April 2009). In addition, lower equity method income from Horizon Power s investments in unconsolidated subsidiaries ($0.6 million) and lower margins from Horizon LFG ($0.5 million) also decreased earnings.

For the nine months ended June 30, 2009, Corporate and All Other had earnings of $2.7 million compared with earnings of $6.8 million for the nine months ended June 30, 2008. The decrease in earnings was largely attributable to lower margins from log and lumber sales ($5.5 million), lower margins from Horizon LFG ($1.4 million), lower interest income ($1.9 million), lower income from Horizon Power s investments in unconsolidated subsidiaries ($1.5 million), and higher interest expense ($1.3 million). The increase in interest expense reflects higher borrowings at a higher interest rate, as mentioned above. In addition, during the quarter ended December 31, 2008, ESNE, an unconsolidated subsidiary of Horizon Power, recorded an impairment charge of $3.6 million. Horizon Power s 50% share of the impairment was $1.8 million ($1.1 million on an after tax basis). Also, Horizon Power recognized a gain on the sale of a turbine ($0.6 million) during 2008 that did not recur in 2009. These earnings decreases were partially offset by lower operating costs ($3.7 million). In 2008, the proxy contest with New Mountain Vantage GP, L.L.C. led to an increase in operating costs, which did not recur in 2009. In addition, lower income tax expense ($3.5 million) and a gain on life insurance policies held by the Company ($2.3 million) further offset the earnings decrease.

Interest Income

Interest income was $1.6 million lower in the quarter ended June 30, 2009 as compared to the quarter ended June 30, 2008. For the nine months ended June 30, 2009, interest income decreased $4.0 million as compared with the nine months ended June 30, 2008. These decreases are mainly due to lower interest rates and lower average temporary cash investment balances.

Other Income

Other income decreased $1.0 million for the quarter ended June 30, 2009 as compared with the quarter ended June 30, 2008. This decrease is attributable to a decrease in the allowance for funds used during construction of $0.9 million in the Pipeline and Storage segment primarily associated with the

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Empire Connector project. For the nine months ended June 30, 2009, other income increased $1.5 million as compared with the nine months ended June 30, 2008. This increase is attributable to an increase in the allowance for funds used during construction of $0.7 million in the Pipeline and Storage segment primarily associated with the Empire Connector project, as well as a death benefit gain on life insurance proceeds of $2.3 million recognized in the Corporate category. Offsetting these increases, as noted above, Horizon Power recognized a pre-tax gain on the sale of a turbine of $0.9 million during the quarter ended March 31, 2008 that did not recur in 2009.

Interest Expense on Long-Term Debt

Interest expense on long-term debt increased $2.3 million for the quarter ended June 30, 2009 as compared with the quarter ended June 30, 2008. For the nine months ended June 30, 2009, interest expense on long-term debt increased $5.3 million as compared with the nine months ended June 30, 2008. The increase is due to a higher average amount of long-term debt outstanding combined with an overall increase in the weighted average interest rate. In April 2008, the Company issued $300 million of 6.5% senior, unsecured notes due in April 2018, and in April 2009, the Company issued $250 million of 8.75% senior, unsecured notes due in May 2019. This increase was partly offset by the repayment of $200 million of 6.303% medium-term notes that matured in May 2008 and the repayment of $100 million of 6.0% medium-term notes that matured in March 2009.

Other Interest Expense

Other Interest expense increased $1.3 million for the quarter ended June 30, 2009 as compared to the quarter ended June 30, 2008. For the nine months ended June 30, 2009, other interest expense increased $0.8 million as compared with the nine months ended June 30, 2008. These increases are mainly due to higher interest expense on regulatory deferrals (primarily deferred gas costs) in the Utility segment.

Effective Tax Rate

The effective tax rate of 32.2% for the nine months ended June 30, 2009 is lower than the effective tax rate of 38.8% for the nine months ended June 30, 2008 due to the reduction in pre-tax income for the nine months ended June 30, 2009. The reduction in pre-tax income is a result of the impairment charge recorded during the quarter ended December 31, 2008 in the Exploration and Production segment.

CAPITAL RESOURCES AND LIQUIDITY

The Company s primary source of cash during the nine-month periods ended June 30, 2009 and June 30, 2008 consisted of cash provided by operating activities and proceeds from the issuance of long-term debt. These sources of cash were supplemented by issues of new shares of common stock as a result of stock option exercises. During the nine months ended June 30, 2009 and June 30, 2008, 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. During the quarter and nine months ended June 30, 2008, the Company repurchased outstanding shares of its common stock under a share repurchase program, which is discussed below under Financing Cash Flow.

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, impairment of oil and gas producing properties, impairment of investment in partnerships, deferred income taxes, and income or loss from unconsolidated subsidiaries net of cash distributions.

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Cash provided by operating activities in the Utility and the Pipeline and Storage segments may vary from period to period because of the impact of rate cases. In the Utility segment, 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 balances receivable at September 30.

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

Cash provided by operating activities in the Exploration and Production segment may vary from period to period as a result of changes in the commodity prices of natural gas and crude oil. The Company uses various derivative financial instruments, including price swap agreements, no cost collars, options and futures contracts in an attempt to manage this energy commodity price risk.

Net cash provided by operating activities totaled $511.8 million for the nine months ended June 30, 2009, an increase of $96.7 million compared with $415.1 million provided by operating activities for the nine months ended June 30, 2008. The increase is primarily due to the timing of gas cost recovery in the Utility segment for the nine months ended June 30, 2009 as compared to the nine months ended June 30, 2008.

Investing Cash Flow

Expenditures for Long-Lived Assets

The Company s expenditures for long-lived assets totaled $230.5 million during the nine months ended June 30, 2009 and $284.6 million for the nine months ended June 30, 2008. The table below presents these expenditures:

Total Expenditures for Long-Lived Assets

Nine Months Ended June 30, (Millions)	2009	2008	Increase (Decrease)
Utility	$ 40.4	$ 38.8	$ 1.6
Pipeline and Storage	34.8(1)	106.2(5)	(71.4)
Exploration and Production	151.7(2)	140.6	11.1
All Other	3.9(3)	1.4	2.5
Eliminations	(0.3) (4)	(2.4)(6)	2.1
	$ 230.5	$ 284.6	$ (54.1)

(1) Amount for the nine months ended June 30, 2009 excludes $16.8 million of accrued capital expenditures related to the Empire

Connector project accrued at September 30, 2008 and paid during the nine months ended June 30, 2009. This amount was excluded from the Consolidated Statement of Cash Flows at September 30, 2008, since it represented a non-cash investing activity at that date. The amount has been included in the Consolidated Statement of Cash Flows at June 30, 2009.

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(2) Amount for the nine months ended June 30, 2009 includes $9.4 million of accrued capital expenditures, the majority of which was in the Appalachian region. This amount has been excluded from the Consolidated Statement of Cash Flows at June 30, 2009 since it represents a non-cash investing activity at that date.

(3) Amount includes a $0.8 million capital contribution made by NFG Midstream Processing, LLC in the Whitetail Processing plant.

(4) Represents $0.3 million of capital expenditures in the Pipeline and Storage segment for the purchase of pipeline facilities from

the Appalachian region of the Exploration and Production segment during the quarter ended December 31, 2008.

(5) Amount includes $19.9 million of accrued capital expenditures related to the Empire Connector project. This amount has been excluded from the Consolidated Statement of Cash Flows at June 30, 2008 since it represents a non-cash investing activity at that date.

(6) Represents $2.4 million of capital expenditures included in the Appalachian region of the Exploration and Production segment for the purchase of storage facilities, buildings, and base gas from Supply Corporation during the

quarter ended
March 31, 2008.

Utility

The majority of the Utility capital expenditures for the nine months ended June 30, 2009 and June 30, 2008 were made for replacement of mains and main extensions, as well as for the replacement of service lines.

Pipeline and Storage

The majority of the Pipeline and Storage capital expenditures for the nine months ended June 30, 2009, and June 30, 2008 were related to the Empire Connector project, which was placed into service on December 10, 2008, as well as for 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 is actively pursuing development of several expansion projects. The largest, Supply Corporation s Appalachian Lateral pipeline project is expected to be routed through areas in Pennsylvania where producers are actively drilling and are seeking market access for their newly discovered reserves. The Appalachian Lateral will complement Supply Corporation s original West to East (W2E) project, which was designed to transport Rockies gas supply from Clarington, Ohio to the Ellisburg/Leidy/Corning area and includes the Tuscarora-to-Corning facilities previously referred to as the Tuscarora Extension. The Appalachian Lateral will transport gas supply from Pennsylvania s producing area to the Overbeck area of Supply Corporation s existing system, where the facilities associated with the W2E project will move the gas to eastern market points, including Leidy, Pennsylvania, and to interconnections with Millennium and Empire at Corning, New York. Preliminary engineering routing analysis, project cost estimate and rate design have been completed, and prospective shippers have been offered precedent agreements for their consideration.

In addition, Supply Corporation is working with the Appalachian producers to develop two strategic compressor horsepower expansions designed to move attached Marcellus production gas to off-system markets. The first involves new compression and approximately 3.5 miles of new pipeline to establish a delivery point from Supply Corporation s Line N to Texas Eastern at Texas Eastern s Holbrook Station near Bristoria in southwestern Pennsylvania. This project will allow local (Marcellus) production located in the vicinity of Line N to flow south and access markets off Texas Eastern s system, with a first phase of service commencing in mid-to-late 2010 and the second phase in late 2011. The second expansion involves the addition of compression at Supply Corporation s existing interconnect with Tennessee Gas Pipeline at Lamont, Pennsylvania, with a projected in-service date early-to-mid-2010.

In conjunction with the Appalachian Lateral and W2E transportation projects, Supply Corporation has plans to develop new storage capacity by expanding certain of its existing storage facilities. The expansion of these fields, which Supply Corporation is pursuing concurrently with the Appalachian Lateral/W2E transportation projects, could provide approximately 8.5 MMDth of incremental storage capacity with incremental withdrawal deliverability of up to 121 MDth of natural gas per day, with service

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commencing as early as 2012. Supply Corporation expects that the availability of this incremental storage capacity will complement the Appalachian Lateral/W2E pipeline transportation projects and help balance the increasing flow of Appalachian and Rockies gas supply into the western Pennsylvania area, and the growing demand for gas on the east coast.

The timeline associated with all of Supply Corporation s pipeline and storage projects will depend on market development. Supply Corporation has not yet filed an application with the FERC for the authority to build any of these projects.

The capital cost of the Appalachian Lateral/W2E transportation projects is estimated to be in the range of $750 million to $1 billion, and is expected to be financed by a combination of debt and equity. Preliminary cost estimates for the storage expansion, Bristoria and Lamont projects are $78 million, $35 million and $6 million, respectively. As of June 30, 2009, approximately $1.0 million has been spent to study the storage expansion project, $0.4 million has been spent to study the Appalachian Lateral/W2E transportation projects, and lesser amounts have been spent on preliminary engineering for the Bristoria and Lamont projects. Costs associated with these projects have been included in preliminary survey and investigation charges and have been fully reserved for at June 30, 2009.

The Company s Empire Connector project has been in service since December 10, 2008, when construction of the actual pipeline and compression facilities was completed, with some right-of-way restoration work remaining to be completed thereafter. During the quarter and nine months ended June 30, 2009, the Company incurred costs of $0.1 million and $21.9 million, respectively, on this project. After June 30, 2009, about $5.3 million, amounting to about 2.8% of the $192 million total project cost, remain to be incurred, almost all of which is expected to be incurred by the end of September 2009.

Exploration and Production

The Exploration and Production segment capital expenditures for the nine months ended June 30, 2009 were primarily well drilling and completion expenditures and included approximately $16.9 million for the Gulf Coast region, substantially all of which was for the off-shore program in the shallow waters of the Gulf of Mexico, $28.8 million for the West Coast region and $106.0 million for the Appalachian region. These amounts included approximately $22.0 million spent to develop proved undeveloped reserves.

In July 2009, the Exploration and Production segment purchased Ivanhoe Energy s United States oil and gas operations for approximately $39.2 million. This purchase complements the segment s existing oil producing assets in the Midway Sunset Field in California. This acquisition was funded with cash on hand.

The Exploration and Production segment capital expenditures for the nine months ended June 30, 2008 included approximately $46.9 million for the Gulf Coast region, substantially all of which was for the off-shore program in the shallow waters of the Gulf of Mexico, $51.1 million for the West Coast region and $42.6 million for the Appalachian region. The Appalachian region capital expenditures included $2.4 million for the purchase of storage facilities, buildings, and base gas from Supply Corporation, as shown in the table on the previous page. These amounts included approximately $20.7 million spent to develop proved undeveloped reserves.

All Other

The majority of the All Other category s capital expenditures for the nine months ended June 30, 2009 were for the construction of Midstream Corporation s Covington Gathering System, as discussed below. The majority of the All Other category s capital expenditures for the nine months ended June 30, 2008 were for construction of a lumber sorter for Highland s sawmill operations as well as for purchases of equipment for Highland s sawmill and kiln operations.

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NFG Midstream Covington, LLC, a wholly owned subsidiary of Midstream Corporation, is constructing a gathering system in Tioga County and Lycoming County in Pennsylvania. The project, called the Covington Gathering System, is to be constructed in three phases, with the first phase under construction and anticipated to be placed in service by the fall of 2009. The second phase is anticipated to be placed in service by the fall of 2010. The schedule for the final phase is being developed. When all three phases are complete, the system will consist of approximately 30 miles of gathering system at a cost of $25 million to $30 million. As of June 30, 2009, the Company has spent approximately $2.8 million in costs on Phase I and Phase II related to this project.

NFG Midstream Processing, LLC, another wholly owned subsidiary of Midstream Corporation, has a 35% ownership in the Whitetail Processing Plant. The plant is currently under construction with completion expected in October 2009. The total project cost is estimated at $4 million. Once completed, the plant will extract natural gas liquids from local production. As of June 30, 2009, the Company invested $0.8 million related to the construction of the plant.

The Company anticipates funding the Midstream Corporation projects with cash from operations and/or short-term borrowings. These expenditures were not included in the estimated capital expenditures reported in the Company s 2008 Form 10-K.

In March 2008, Horizon Power sold a gas-powered turbine that it had planned to use in the development of a co-generation plant. Horizon Power received proceeds of $5.3 million and recorded a pre-tax gain of $0.9 million associated with the sale.

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

Financing Cash Flow

The Company did not have any outstanding short-term notes payable to banks or commercial paper at June 30, 2009. However, the Company continues to consider short-term debt (consisting of short-term notes payable to banks and commercial paper) an important source of cash for temporarily financing capital expenditures and investments in corporations and/or partnerships, gas-in-storage inventory, unrecovered purchased gas costs, margin calls on derivative financial instruments, exploration and development expenditures, repurchases of stock, and other working capital needs. Fluctuations in these items can have a significant impact on the amount and timing of short-term debt. As for bank loans, the Company maintains a number of individual uncommitted or discretionary lines of credit with certain financial institutions for general corporate purposes. Borrowings under these lines of credit are made at competitive market rates. These credit lines, which aggregate to $420.0 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 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, 2010.

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, 2010. At June 30, 2009, the Company s debt to capitalization ratio (as calculated under the facility) was .43. The constraints specified in the committed credit facility would permit an additional $1.78 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

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

Under the Company s existing indenture covenants, at June 30, 2009, the Company would have been permitted to issue up to a maximum of $495.0 million 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 another impairment of oil and gas properties this year, it is possible that these indenture covenants would restrict the Company s ability to issue additional long-term unsecured indebtedness. This would not preclude the Company from issuing new indebtedness to replace maturing debt.

The Company s 1974 indenture pursuant to which $99.0 million (or 7.9%) of the Company s long-term debt (as of June 30, 2009) was issued, contains a cross-default provision whereby the failure by the Company to perform certain obligations under other borrowing arrangements could trigger an obligation to repay the debt outstanding under the indenture. In particular, a repayment obligation could be triggered if the Company fails (i) to pay any scheduled principal or interest on any debt under any other indenture or agreement or (ii) to perform any other term in any other such indenture or agreement, and the effect of the failure causes, or would permit the holders of the debt to cause, the debt under such indenture or agreement to become due prior to its stated maturity, unless cured or waived.

The Company s $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 $20.0 million or more or (ii) an event occurs that causes, or would permit the holders of any other indebtedness aggregating $20.0 million or more to cause, such indebtedness to become due prior to its stated maturity. As of June 30, 2009, the Company had no debt outstanding under the committed credit facility.

In April 2008, the Company issued $300.0 million of 6.50% senior, unsecured notes in a private placement exempt from registration under the Securities Act of 1933. In February 2009, the Company exchanged the notes for economically identical notes registered under the Securities Act of 1933. The notes have a term of 10 years, with a maturity date in April 2018. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of a change in control and a ratings downgrade to a rating below investment grade. The Company used $200.0 million of the proceeds of the issuance to refund $200.0 million of 6.303% medium-term notes that matured on May 27, 2008.

In April 2009, the Company issued $250.0 million of 8.75% notes due in March 2019. After deducting underwriting discounts and commissions, the net proceeds to the Company amounted to $247.8 million. The holders of the notes may require the Company to repurchase their notes at a price equal to 101% of the principal amount in the event of a change in control and a ratings downgrade to a rating below investment grade. The proceeds of this debt issuance were used for general corporate purposes, including to replenish cash that was used to pay the $100 million due at the maturity of the Company s 6.0% medium-term notes on March 1, 2009. After this debt issuance, the Company s embedded cost of long-term debt increased from 6.5% to 6.95%. If the Company were to issue long-term debt today, its borrowing costs might be expected to be in the range of 7.0% to 8.0% depending on the length of maturity.

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On December 8, 2005, the Company s Board of Directors authorized the Company to implement a share repurchase program, whereby the Company could repurchase outstanding shares of common stock, up to an aggregate amount of 8 million shares in the open market or through privately negotiated transactions. The Company repurchased 439,722 and 2,832,397 shares for $20.7 million and $129.6 million, respectively, during the quarter and nine months ended June 30, 2008 under this program. The Company completed the repurchase of the 8 million shares during the last quarter of fiscal 2008. In September 2008, the Company s Board of Directors authorized the repurchase of an additional 8 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. Such repurchases may resume in the future. The share repurchases mentioned above were funded with cash provided by operating activities.

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 and capital 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 $27.7 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. The Company s unconsolidated subsidiaries, which are accounted for under the equity method, have capital leases of electric generating equipment having a remaining lease commitment of approximately $2.3 million. The Company has guaranteed 50% or $1.1 million of these capital lease commitments.

OTHER MATTERS

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

During the nine months ended June 30, 2009, the Company contributed $16.0 million to its retirement plan and $21.5 million to its VEBA trusts and 401(h) accounts for its other post-retirement benefits. In the remainder of 2009, the Company does not expect to contribute to its retirement plan. As a result of the recent downturn in the stock markets and general economic conditions, it is expected that the Company will fund in the range of $20 million to $40 million to the retirement plan subsequent to fiscal 2009. In the remainder of 2009, the Company expects to contribute approximately $5.0 million to its VEBA trusts and 401(h) accounts.

Market Risk Sensitive Instruments

Beginning in fiscal 2009, the Company adopted the provisions of SFAS 157. In accordance with the adoption of SFAS 157, the Company has identified certain inputs used to recognize fair value as Level 3 (unobservable inputs). The Level 3 derivative assets relate to natural gas and oil swap agreements used to hedge forecasted sales at specific locations (southern California and the Texas-Oklahoma border). The Company s internal model that is used to calculate fair value applies a historical basis

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differential (between the sales locations and NYMEX) to a forward NYMEX curve because there is not a forward curve specific to these sales locations. Given the high level of historical correlation between NYMEX prices and prices at these sales locations, the Company does not believe that the fair values recorded by the Company would be significantly different from what it expects to receive upon settlement. The fair value of the Level 3 derivative assets was reduced by $0.7 million based upon the Company s assessment of counterparty credit risk. The Company applied default probabilities to the anticipated cash flows that it was expecting from its counterparties to calculate the credit reserve. The Company incorporated hedging collateral deposits received from the counterparties in calculating the credit reserve.

The Level 3 assets amount to $34.5 million at June 30, 2009 and represent 52% of the Derivative Financial Instruments Assets or 7% of the Total Assets shown in Part I, Item 1 at Note 2 Fair Value Measurements at June 30, 2009.

At June 30, 2009, the Company transferred $9.8 million of derivative assets from Level 3 assets to Level 2 assets. These assets related to the natural gas swaps on southern California natural gas production. This transfer occurred because the Company was able to obtain and utilize forward-looking, observable basis differential information for the underlying hedges at this location. In the prior quarters, the Company utilized historical basis differentials at this location. Also, at June 30, 2009, the Company transferred $1.3 million of derivative assets from Level 2 assets to Level 3 assets. These assets related to certain natural gas swaps on Gulf of Mexico natural gas production. Since the basis differential related to these natural gas swaps could no longer be considered immaterial and the Company could only utilize historical basis differential information to estimate the basis differential, these positions were considered Level 3.

The Company uses the natural gas and crude oil swaps to hedge against the risk of declining commodity prices and not as speculative investments. Gains or losses related to these Level 3 derivative assets (including any reduction for credit risk) are deferred until the hedged commodity transaction occurs in accordance with the provisions of SFAS 133.

The significant increase in the fair value of the Level 3 assets from October 1, 2008 to June 30, 2009, as shown in Part I, Item 1 at Note 2, was attributable to a significant decrease in the commodity price of natural gas and crude oil during that period. The Company believes that these fair values reasonably represent the amounts that the Company would realize upon settlement based on commodity prices that were present at June 30, 2009.

For a complete discussion of market risk sensitive instruments, refer to Market Risk Sensitive Instruments in Item 7 of the Company s 2008 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

Base rate adjustments in both the New York and Pennsylvania rate jurisdictions do not reflect the recovery of purchased gas costs. Such costs are recovered through operation of the purchased gas adjustment clauses of the appropriate regulatory authorities.

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 recover 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 also adopted Distribution Corporation s proposed revenue decoupling mechanism. The revenue decoupling mechanism, like others, decouples revenues from throughput by enabling the Company to collect from small volume customers its allowed margin on average weather normalized

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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 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 contends that portions of the rate order should be invalidated because they fail to meet the applicable legal standard for agency decisions. Among the issues challenged by the Company are the reasonableness of the NYPSC s disallowance of expense items and the methodology used for calculating rate of return, which the appeal contends understated the Company s cost of equity. Briefs have been filed and oral argument is scheduled to be held in October 2009. The Company cannot predict the outcome of the appeal at this time.

On April 7, 2009, the Governor of the State of New York signed into law an amendment to the Public Service Law increasing the utility assessment from the current rate of 1/3 of one percent to one percent of a utility s in-state gross operating revenue, together with a temporary surcharge equal, as applied, to an additional one percent of the utility s gross operating revenue. The amendment is expected to increase the assessment charged to Distribution Corporation s New York Division, based on the most current calculation, from $2.3 million to approximately $26 million, all other things being equal. The NYPSC, in a generic proceeding initiated for the purpose of implementing the amended law, has provided for recovery, through rates, of the full cost of the increased assessment.

Pennsylvania Jurisdiction

Distribution Corporation currently does not have a rate case on file with the PaPUC. Distribution Corporation s current tariff in its Pennsylvania jurisdiction was last 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 make a filing at the FERC, within three years after the in-service date, either justifying Empire s existing recourse rates or proposing 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.

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 $16.0 million.

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At June 30, 2009, 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 $19.0 million to $23.2 million. The minimum estimated liability of $19.0 million, which includes the $16.0 million discussed above, has been recorded on the Consolidated Balance Sheet at June 30, 2009. The Company expects to recover its environmental clean-up costs from a combination of rate recovery and deferred insurance proceeds that are currently recorded as a regulatory liability on the Consolidated Balance Sheet.

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 Accounting Pronouncements

In September 2006, the FASB issued SFAS 157. SFAS 157 provides guidance for using fair value to measure assets and liabilities. The pronouncement serves to clarify the extent to which companies measure assets and liabilities at fair value, the information used to measure fair value, and the effect that fair-value measurements have on earnings. SFAS 157 is to be applied whenever another standard requires or allows assets or liabilities to be measured at fair value. In accordance with FASB Staff Position FAS No. 157-2, on October 1, 2008, the Company adopted SFAS 157 for financial assets and financial liabilities that are recognized or disclosed at fair value on a recurring basis. The same FASB Staff Position delays the effective date for nonfinancial assets and nonfinancial liabilities, except for items that are recognized or disclosed at fair value on a recurring basis, until the Company s first quarter of fiscal 2010. For further discussion of the impact of the adoption of SFAS 157 for financial assets and financial liabilities, refer to Part I, Item 1 at Note 2 Fair Value Measurements. The Company is currently evaluating the impact that the adoption of SFAS 157 for nonfinancial assets and nonfinancial liabilities will have on its consolidated financial statements. The Company has identified Goodwill as being the major nonfinancial asset that may be impacted by the adoption of SFAS 157. The Company does not believe there are any nonfinancial liabilities that will be impacted by the adoption of SFAS 157.

In September 2006, the FASB issued SFAS 158, an amendment of SFAS 87, SFAS 88, SFAS 106, and SFAS 132R. SFAS 158 requires that companies recognize a net liability or asset to report the underfunded or overfunded status of their defined benefit pension and other post-retirement benefit plans on their balance sheets, as well as recognize changes in the funded status of a defined benefit post-retirement plan in the year in which the changes occur through comprehensive income. The pronouncement also specifies that a plan s assets and obligations that determine its funded status be measured as of the end of the Company s fiscal year, with limited exceptions. In accordance with SFAS 158, the Company has recognized the funded status of its benefit plans and implemented the disclosure requirements of SFAS 158 at September 30, 2007. The requirement to measure the plan assets and benefit obligations as of the Company s fiscal year-end date will be fully adopted by the Company by the end of fiscal 2009. The Company has historically measured its plan assets and benefit obligations using a June 30th measurement date. In anticipation of changing to a September 30th measurement date, the Company will be recording fifteen months of pension and other post-retirement benefit costs during fiscal 2009. In accordance with the provisions of SFAS 158, these costs have been calculated using June 30, 2008 measurement date data. Three of those months pertain to the period of July 1, 2008 to September 30, 2008. The pension and other post-retirement benefit costs for that period amounted to $5.1 million and have been recorded by the Company during the quarter ended December 31, 2008 as a $3.8 million increase to Other Regulatory Assets in the Company s Utility and Pipeline and Storage segments and a $1.3 million ($0.8 million after tax) adjustment to earnings reinvested in the business. For further discussion of the impact of adopting the measurement date provisions of SFAS 158, refer to Part I, Item 1 at Note 9 Retirement Plan and Other Post-Retirement Benefits.

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In December 2007, the FASB issued SFAS 141R. SFAS 141R will significantly change the accounting for business combinations in a number of areas including the treatment of contingent consideration, contingencies, acquisition costs, in process research and development and restructuring costs. In addition, under SFAS 141R, changes in deferred tax asset valuation allowances and acquired income tax uncertainties in a business combination after the measurement period will impact income tax expense. SFAS 141R is effective as of the Company s first quarter of fiscal 2010.

In December 2007, the FASB issued SFAS 160. SFAS 160 will change the accounting and reporting for minority interests, which will be recharacterized as noncontrolling interests (NCI) and classified as a component of equity. This new consolidation method will significantly change the accounting for transactions with minority interest holders. SFAS 160 is effective as of the Company s first quarter of fiscal 2010. The Company currently does not have any NCI.

In March 2008, the FASB issued SFAS 161. SFAS 161 requires entities to provide enhanced disclosures related to an entity s derivative instruments and hedging activities in order to enable investors to better understand how derivative instruments and hedging activities impact an entity s financial reporting. The additional disclosures include how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and how derivative instruments and related hedged items affect an entity s financial position, financial performance, and cash flows. The Company adopted the disclosure provisions of SFAS 161 during the quarter ended March 31, 2009. These disclosures may be found at Part I, Item 1 at Note 3 Financial Instruments.

On December 31, 2008, the SEC issued a final rule on Modernization of Oil and Gas Reporting. The final rule modifies the SEC s reporting and disclosure rules for oil and gas reserves and aligns the full cost accounting rules with the revised disclosures. The most notable changes of the final rule include the replacement of the single day period-end pricing to value oil and gas reserves to a 12-month average of the first day of the month price for each month within the reporting period. The final rule also permits voluntary disclosure of probable and possible reserves, a disclosure previously prohibited by SEC rules. The revised reporting and disclosure requirements are effective for the Company s Form 10-K for the period ended September 30, 2010. Early adoption is not permitted. The Company is currently evaluating the impact that adoption of these rules will have on its consolidated financial statements and MD&A disclosures.

Effective April 1, 2009, the Company adopted FASB Staff Position FAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments. This FASB Staff Position amends SFAS 107, Disclosures about Fair Value of Financial Instruments, to require disclosures about fair value of financial instruments for interim reporting periods of publicly traded companies as well as in annual financial statements. Refer to Part I, Item 1 at Note 3 Financial Instruments under Long-Term Debt for additional disclosures included in accordance with this FASB Staff Position.

Effective with this June 30, 2009 Form 10-Q, the Company adopted SFAS 165. SFAS 165 establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Refer to Part I, Item 1 at Note 10 Subsequent Events for disclosures made as a result of the adoption of SFAS 165.

In June 2009, the FASB issued SFAS 168. SFAS 168 establishes the FASB Accounting Standards Codification™ (the Codification) as the source of authoritative GAAP recognized by the FASB to be applied by all nongovernmental entities in the preparation of financial statements in conformity with GAAP. Rules and interpretive releases of the SEC under authority of federal securities law are also sources of authoritative GAAP for SEC registrants. All other nongrandfathered, non-SEC accounting literature not included in the Codification will become nonauthoritative. SFAS 168 is effective for interim and annual periods ending after September 15, 2009. The Company will update its disclosures to conform to the Codification in its annual report on Form 10-K for the year ending September 30, 2009. There will be no impact on the Company s consolidated financial statements as the Codification does not change or alter existing GAAP.

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

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, strategies, future events or performance and underlying assumptions, capital structure, anticipated capital expenditures, completion of construction projects, projections for pension and other post-retirement benefit obligations, impacts of the adoption of new accounting rules, and possible outcomes of litigation or regulatory proceedings, as well as statements that are identified by the use of the words anticipates, estimates, expects, forecasts, intends, plans, predicts, projects, believes, seek similar expressions, are forward-looking statements as defined in the Private Securities Litigation Reform Act of 1995 and accordingly involve risks and uncertainties which could cause actual results or outcomes to differ materially from those expressed in the forward-looking statements. The 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 their effect on the Company s ability to obtain financing on acceptable terms for working capital, capital expenditures and other investments;

2. Occurrences affecting the Company s ability to obtain financing under credit lines or other credit facilities or through the issuance of commercial paper, other short-term notes or debt or equity securities, including any downgrades in the Company s credit ratings and changes in interest rates and other capital market conditions;

3. 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;

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

5. 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;

6. 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;

7. Changes in demographic patterns and weather conditions;

8. 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 or the valuation of the Company s natural gas and oil reserves;

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

9. Impairments under the SEC s full cost ceiling test for natural gas and oil reserves;
10. Uncertainty of oil and gas reserve estimates;
11. 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, and the need to obtain governmental approvals and permits and comply with environmental laws and regulations;
12. Significant differences between the Company s projected and actual production levels for natural gas or oil;
13. Changes in the availability and/or price of derivative financial instruments;
14. Changes in the price differentials between oil having different quality and/or different geographic locations, or changes in the price differentials between natural gas having different heating values and/or different geographic locations;
15. Inability to obtain new customers or retain existing ones;
16. Significant changes in competitive factors affecting the Company;
17. Changes in laws and regulations to which the Company is subject, including tax, environmental, safety and employment laws and regulations;
18. Governmental/regulatory actions, initiatives and proceedings, including those involving 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;
19. Unanticipated impacts of restructuring initiatives in the natural gas and electric industries;
20. Significant differences between the Company s projected and actual capital expenditures and operating expenses and unanticipated project delays or changes in project costs or plans;
21. The nature and projected profitability of pending and potential projects and other investments, and the ability to obtain necessary governmental approvals and permits;
22. Ability to successfully identify and finance acquisitions or other investments and ability to operate and integrate existing and any subsequently acquired business or properties;
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.

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

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

Item 3. Quantitative and Qualitative Disclosures About Market Risk

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

Item 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

The term disclosure controls and procedures is defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act. These rules refer to the controls and other procedures of a company that are designed to ensure that information required to be disclosed by a company in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to the company s management, including its principal executive and principal financial officers, as appropriate to allow timely decisions regarding required disclosure. The Company s management, including the Chief Executive Officer and Principal Financial Officer, evaluated the effectiveness of the Company s disclosure controls and procedures as of the end of the period covered by this report. Based upon that evaluation, the Company s Chief Executive Officer and Principal Financial Officer concluded that the Company s disclosure controls and procedures were effective as of June 30, 2009.

Changes in Internal Controls Over Financial Reporting

There were no changes in the Company s internal control over financial reporting that occurred during the quarter ended June 30, 2009 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Part II. Other Information

Item 1. Legal Proceedings

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

In addition to these matters, the Company is involved in other litigation and regulatory matters arising in the normal course of business. These other matters may include, for example, negligence claims and tax, regulatory or other governmental audits, inspections, investigations or other proceedings. These matters may involve state and federal taxes, safety, compliance with regulations, rate base, cost of service, and purchased gas cost issues, among other things. While these 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 2008 Form 10-K, as amended by Item 1A of the Company s Forms 10-Q for the quarters ended December 31, 2008 and March 31, 2009, 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 2008 Form 10-K and the December 31, 2008 and March 31, 2009 Forms 10-Q and should otherwise be read in conjunction with all of the risk factors disclosed in those reports.

Item 1A. **Risk Factors (Concl.)**

National Fuel 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 National Fuel 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 National Fuel 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 affect its business in ways that the Company cannot predict.

In its Utility segment, the operations of Distribution Corporation are subject to the jurisdiction of the NYPSC and the PaPUC. 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 sought to establish competitive markets in which customers may purchase supplies of gas from marketers, rather than from utility companies. In June 1999, the Governor of Pennsylvania signed into law the Natural Gas Choice and Competition Act. The Act revised the Public Utility Code relating to the restructuring of the natural gas industry, to permit consumer choice of natural gas suppliers. The early programs instituted to comply with the Act did not result in significant change, and many residential customers currently continue to purchase natural gas from the utility companies. In October 2005, the PaPUC concluded that effective competition does not exist in the retail natural gas supply market statewide. On September 11, 2008, the PaPUC adopted a Final Order and Action Plan designed to increase effective competition in the retail market for natural gas services. The plan sets forth a schedule of action items for utilities and the PaPUC in order to remove barriers in the market structure that, in the opinion of the PaPUC, prevented the full participation of unregulated natural gas suppliers in Pennsylvania retail markets. In New York, in August 2004, the NYPSC issued its Statement of Policy on Further Steps Toward Competition in Retail Energy Markets. This policy statement has a similar goal of encouraging customer choice of alternative natural gas providers. In 2005, the NYPSC stepped up its efforts to encourage customer choice at the retail residential level, and customer choice activities increased in Distribution Corporation s New York service territory. In April 2007, the NYPSC, noting that the retail energy marketplace in New York is established and continuing to expand, commenced a review to determine if existing programs initially designed to promote competition had outlived their usefulness and whether the cost of programs currently funded by utility rate payers should be shifted to market competitors. Increased retail choice activities, to the extent they occur, may increase Distribution Corporation s cost of doing business, put an additional portion of its business at regulatory risk, and create uncertainty for the future, all of which may make it more difficult to manage Distribution Corporation s business profitably.

Both the NYPSC and the PaPUC have instituted proceedings for the purpose of promoting conservation of energy commodities, including natural gas. In New York, Distribution Corporation implemented a Conservation Incentive Program that promotes conservation and efficient use of natural gas by offering customer rebates for high-efficiency appliances, among other things. The intent of conservation and efficiency programs is to reduce customer usage of natural gas. Under traditional volumetric rates, reduced usage by customers results in decreased revenues to the Utility. To prevent revenue erosion caused by conservation, the NYPSC approved a revenue decoupling mechanism that renders Distribution Corporation s New York division financially indifferent to the effects of conservation. In Pennsylvania, although a 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

Item 1A. Risk Factors (Concl.)

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 its Pipeline and Storage segment, National Fuel is subject to the jurisdiction of the FERC with respect to Supply Corporation and Empire. 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.

Environmental regulation significantly affects National Fuel s business.

National Fuel 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 National Fuel s results of operations, financial condition and cash flows. In addition, compliance with environmental laws and regulations could require unexpected capital expenditures at National Fuel 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 National Fuel s business. Although National Fuel cannot predict the impact of the interpretation or enforcement of EPA standards or other federal, state and local regulations, National Fuel s costs could increase if environmental laws and regulations become more strict.

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

On April 1, 2009, the Company issued a total of 2,800 unregistered shares of Company common stock to the seven non-employee directors of the Company then serving on the Board of Directors of the Company and receiving compensation under the Company s Retainer Policy for Non-Employee Directors, 400 shares to each such director. All of these unregistered shares were issued as partial consideration for the directors services during the quarter ended June 30, 2009. These transactions were exempt from registration by Section 4(2) of the Securities Act of 1933 as transactions not involving a public offering.

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased[a]	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Share Repurchase Plans or Programs	Maximum Number of Shares that May Yet Be Purchased Under Share Repurchase Plans or Programs[b]
Apr. 1 - 30, 2009	11,818	$ 31.05		6,971,019
May 1 - 31, 2009	12,103	$ 31.02		6,971,019
June 1 - 30, 2009	14,508	$ 35.24		6,971,019

Total	38,429	$ 32.62	6,971,019

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds (Concl.)

[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 June 30, 2009, the Company did not purchase any shares of its common stock pursuant to its publicly announced share repurchase program. Of the 38,429 shares purchased other than through a publicly announced share repurchase program, 34,661 were purchased

for the Company s 401(k) plans and 3,768 were purchased as a result of shares tendered to the Company by holders of stock options or shares of restricted stock.

(b) In December 2005, the Company s Board of Directors authorized the repurchase of up to eight million shares of the Company s common stock. The Company completed the repurchase of the eight million shares during 2008. In September 2008, the Company s Board of Directors authorized the repurchase of an additional 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. However, such repurchases may be made in the future if conditions improve. Such repurchases would be made in the open market or through private transactions.

Item 6. Exhibits

(a) Exhibits

Exhibit Number	Description of Exhibit
4	Instruments defining the rights of security holders:
	Officer s Certificate establishing 8.75% Notes due 2019, dated April 6, 2009 (incorporated by reference to Exhibit 4.4, Form 8-K dated April 6, 2009).
10	Material contracts:
10.1	Agreement to Extend Duration of Director Services Agreement, dated June 1, 2009, between National Fuel Gas Company and Philip C. Ackerman
12	Statements regarding Computation of Ratios: Ratio of Earnings to Fixed Charges for the Twelve Months Ended June 30, 2009 and the Fiscal Years Ended September 30, 2005 through 2008.
31.1	Written statements of Chief Executive Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934.
31.2	Written statements of Principal Financial Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934.
32	Certification Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99	National Fuel Gas Company Consolidated Statements of Income for the Twelve Months Ended June 30, 2009 and 2008.

Incorporated herein by reference as indicated.

SIGNATURES

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

NATIONAL FUEL GAS COMPANY
(Registrant)

/s/ R. J. Tanski
R. J. Tanski
Treasurer and Principal Financial Officer

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

Date: August 7, 2009