OGE ENERGY CORP.
Form 10-Q
October 29, 2010

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-Q

(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2010

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____to_____

Commission File Number: 1-12579

OGE ENERGY CORP.
(Exact name of registrant as specified in its charter)

Oklahoma (State or other jurisdiction of incorporation or organization)	73-1481638 (I.R.S. Employer Identification No.)

321 North Harvey
P.O. Box 321
Oklahoma City, Oklahoma 73101-0321
(Address of principal executive offices)
(Zip Code)

405-553-3000
(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 (or for such shorter period that the registrant was required to file such reports), 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). þ Yes o No

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

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

At September 30, 2010, there were 97,476,755 shares of common stock, par value $0.01 per share, outstanding.

OGE ENERGY CORP.

FORM 10-Q

FOR THE QUARTER ENDED SEPTEMBER 30, 2010

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FORWARD-LOOKING STATEMENTS

Except for the historical statements contained herein, the matters discussed in this Form 10-Q, including those matters discussed in “Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations,” are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words “anticipate”, “believe”, “estimate”, “expect”, “inten “objective”, “plan”, “possible”, “potential”, “project” and similar expressions. Actual results may vary materially from tho expressed in forward-looking statements. In addition to the specific risk factors discussed in “Item 1A. Risk Factors” in OGE Energy Corp.’s Annual Report on Form 10-K for the year ended December 31, 2009 (“2009 Form 10-K”) and “Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations” herein, factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to:

- general economic conditions, including the availability of credit, access to existing lines of credit, access to the commercial paper markets, actions of rating agencies and their impact on capital expenditures;
- the ability of OGE Energy Corp. (collectively, with its subsidiaries, the “Company”) and its subsidiaries to access the capital markets and obtain financing on favorable terms;
- prices and availability of electricity, coal, natural gas and natural gas liquids, each on a stand-alone basis and in relation to each other;
- business conditions in the energy and natural gas midstream industries;
- competitive factors including the extent and timing of the entry of additional competition in the markets served by the Company;
- unusual weather;
- availability and prices of raw materials for current and future construction projects;
- Federal or state legislation and regulatory decisions and initiatives that affect cost and investment recovery, have an impact on rate structures or affect the speed and degree to which competition enters the Company’s markets;
- environmental laws and regulations that may impact the Company’s operations;
- changes in accounting standards, rules or guidelines;
- the discontinuance of accounting principles for certain types of rate-regulated activities;
- creditworthiness of suppliers, customers and other contractual parties;
- the higher degree of risk associated with the Company’s nonregulated business compared with the Company’s regulated utility business;
- the risk that the proposed transaction with Bronco Midstream Holdings LLC will not be completed, or will not be completed on the terms currently contemplated; and
- other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission including those listed in “Item 1A. Risk Factors” and in Exhibit 99.01 to the Company’s 2009 Form 10-K.

The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.

OGE ENERGY CORP.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME
(Unaudited)

(In millions, except per share data)	Three Months Ended September 30, 2010	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2010	Nine Months Ended September 30, 2009
OPERATING REVENUES				
Electric Utility operating revenues	$ 723.0	$ 577.9	$ 1,679.8	$ 1,339.9
Natural Gas Pipeline operating revenues	402.4	267.4	1,208.6	756.1
Total operating revenues	1,125.4	845.3	2,888.4	2,096.0
COST OF GOODS SOLD (exclusive of depreciation and amortization shown below)				
Electric Utility cost of goods sold	299.4	223.8	757.2	559.3
Natural Gas Pipeline cost of goods sold	313.2	190.3	932.0	532.2
Total cost of goods sold	612.6	414.1	1,689.2	1,091.5
Gross margin on revenues	512.8	431.2	1,199.2	1,004.5
OPERATING EXPENSES				
Other operation and maintenance	142.4	113.0	401.0	335.1
Depreciation and amortization	73.7	67.2	215.2	195.8
Taxes other than income	22.5	21.3	70.5	65.5
Total operating expenses	238.6	201.5	686.7	596.4
OPERATING INCOME	274.2	229.7	512.5	408.1
OTHER INCOME (EXPENSE)				
Interest income	---	0.3	---	1.4
Allowance for equity funds used during construction	2.6	5.5	7.2	10.7
Other income	0.6	7.0	5.8	20.0
Other expense	(2.7)	(3.9)	(8.8)	(8.9)
Net other income	0.5	8.9	4.2	23.2
INTEREST EXPENSE				
Interest on long-term debt	36.3	37.3	103.3	100.6
Allowance for borrowed funds used during construction	(1.3)	(2.9)	(3.5)	(5.9)
Interest on short-term debt and other interest charges	1.4	2.3	4.7	6.4
Interest expense	36.4	36.7	104.5	101.1
INCOME BEFORE TAXES	238.3	201.9	412.2	330.2
INCOME TAX EXPENSE	74.8	64.4	145.6	104.2
NET INCOME	163.5	137.5	266.6	226.0
Less: Net income attributable to noncontrolling interest	0.4	0.7	2.0	1.9
NET INCOME ATTRIBUTABLE TO OGE ENERGY	$ 163.1	$ 136.8	$ 264.6	$ 224.1
BASIC AVERAGE COMMON SHARES OUTSTANDING	97.4	96.7	97.3	96.0
DILUTED AVERAGE COMMON SHARES OUTSTANDING	99.0	97.7	98.8	96.9
BASIC EARNINGS PER AVERAGE COMMON SHARE ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS	$ 1.67	$ 1.42	$ 2.72	$ 2.34

DILUTED EARNINGS PER AVERAGE COMMON SHARE				
ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS	$ 1.65	$ 1.40	$ 2.68	$ 2.31
DIVIDENDS DECLARED PER COMMON SHARE	$ 0.3625	$ 0.3550	$ 1.0875	$ 1.0650

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)

	Nine Months Ended September 30,	
(In millions)	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	$ 266.6	$ 226.0
Adjustments to reconcile net income to net cash provided from operating activities		
Depreciation and amortization	215.2	195.8
Deferred income taxes and investment tax credits, net	146.8	132.3
Allowance for equity funds used during construction	(7.2)	(10.7)
Stock-based compensation expense	4.9	2.5
Excess tax benefit on stock-based compensation	(0.7)	(3.3)
Price risk management assets	2.3	6.6
Price risk management liabilities	6.2	(67.7)
Regulatory assets	7.4	13.4
Regulatory liabilities	(10.7)	(12.4)
Other assets	14.3	(0.8)
Other liabilities	(10.5)	(42.2)
Change in certain current assets and liabilities		
Accounts receivable, net	(48.0)	2.8
Accrued unbilled revenues	(11.2)	(12.5)
Income taxes receivable	141.2	(40.5)
Fuel, materials and supplies inventories	(12.3)	(26.1)
Gas imbalance assets	---	(1.8)
Fuel clause under recoveries	(0.6)	23.7
Other current assets	7.8	6.8
Accounts payable	(13.7)	(105.0)
Gas imbalance liabilities	(1.0)	(15.2)
Fuel clause over recoveries	(119.5)	167.8
Other current liabilities	9.6	(0.2)
Net Cash Provided from Operating Activities	586.9	439.3
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures (less allowance for equity funds used during construction)	(591.3)	(689.1)
Construction reimbursement	3.3	32.9
Proceeds from sale of assets	1.9	0.8
Other investing activities	0.1	---
Net Cash Used in Investing Activities	(586.0)	(655.4)
CASH FLOWS FROM FINANCING ACTIVITIES		
Retirement of long-term debt	(289.2)	(110.8)
Dividends paid on common stock	(105.7)	(101.8)
Repayment of line of credit	(80.0)	(110.0)
Excess tax benefit on stock-based compensation	0.7	3.3

Issuance of common stock	13.5	74.9
Increase in short-term debt	49.0	10.0
Proceeds from line of credit	115.0	80.0
Proceeds from long-term debt	246.2	198.4
Net Cash (Used in) Provided from Financing Activities	(50.5)	44.0
NET DECREASE IN CASH AND CASH EQUIVALENTS	(49.6)	(172.1)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	58.1	174.4
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 8.5	$ 2.3

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS

(In millions)	September 30, 2010 (Unaudited)	December 31, 2009
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 8.5	$ 58.1
Accounts receivable, less reserve of $2.2 and $2.4, respectively	339.4	291.4
Accrued unbilled revenues	68.4	57.2
Income taxes receivable	16.5	157.7
Fuel inventories	126.3	118.5
Materials and supplies, at average cost	82.9	78.4
Price risk management	3.4	1.8
Gas imbalances	3.2	3.2
Deferred income taxes	48.7	39.8
Fuel clause under recoveries	0.9	0.3
Other	10.9	19.7
Total current assets	709.1	826.1
OTHER PROPERTY AND INVESTMENTS, at cost	42.0	43.7
PROPERTY, PLANT AND EQUIPMENT		
In service	9,039.8	8,617.8
Construction work in progress	405.5	335.4
Total property, plant and equipment	9,445.3	8,953.2
Less accumulated depreciation	3,157.7	3,041.6
Net property, plant and equipment	6,287.6	5,911.6
DEFERRED CHARGES AND OTHER ASSETS		
Regulatory assets	454.3	448.9
Price risk management	0.4	4.3
Other	34.0	32.1
Total deferred charges and other assets	488.7	485.3
TOTAL ASSETS	$ 7,527.4	$ 7,266.7

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

(In millions)	September 30, 2010 (Unaudited)	December 31, 2009
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 224.0	$ 175.0
Long-term debt due within one year	---	289.2
Accounts payable	266.2	297.0
Dividends payable	35.3	35.1
Customer deposits	67.0	85.6
Accrued taxes	57.2	37.0
Accrued interest	30.2	60.6
Accrued compensation	46.1	50.1
Price risk management	13.9	14.2
Gas imbalances	11.0	12.0
Fuel clause over recoveries	68.0	187.5
Other	53.1	32.4
Total current liabilities	872.0	1,275.7
LONG-TERM DEBT	2,372.8	2,088.9
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued benefit obligations	331.2	369.3
Deferred income taxes	1,422.4	1,246.6
Deferred investment tax credits	10.3	13.1
Regulatory liabilities	185.1	168.2
Price risk management	1.8	0.1
Deferred revenues	37.2	---
Other	46.3	44.0
Total deferred credits and other liabilities	2,034.3	1,841.3
Total liabilities	5,279.1	5,205.9
COMMITMENTS AND CONTINGENCIES (NOTE 13)		
STOCKHOLDERS' EQUITY		
Common stockholders' equity	908.7	887.7
Retained earnings	1,386.5	1,227.8
Accumulated other comprehensive loss, net of tax	(68.9)	(74.7)
Total OGE Energy stockholders' equity	2,226.3	2,040.8
Noncontrolling interest	22.0	20.0
Total stockholders' equity	2,248.3	2,060.8
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 7,527.4	$ 7,266.7

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY
(Unaudited)

(In millions)	Common Stock	Premium on Capital Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total
Balance at December 31, 2009	$ 1.0	$ 886.7	$ 1,227.8	$ (74.7)	$ 20.0	$ 2,060.8
Comprehensive income						
Net income	---	---	264.6	---	2.0	266.6
Other comprehensive income, net of tax	---	---	---	5.8	---	5.8
Comprehensive income	---	---	264.6	5.8	2.0	272.4
Dividends declared on common stock	---	---	(105.9)	---	---	(105.9)
Issuance of common stock	---	21.0	---	---	---	21.0
Balance at September 30, 2010	$ 1.0	$ 907.7	$ 1,386.5	$ (68.9)	$ 22.0	$ 2,248.3
Balance at December 31, 2008	$ 0.9	$ 802.0	$ 1,107.6	$ (13.7)	$ 17.2	$ 1,914.0
Comprehensive income (loss)						
Net income	---	---	224.1	---	1.9	226.0
Other comprehensive loss, net of tax	---	---	---	(43.5)	---	(43.5)
Comprehensive income (loss)	---	---	224.1	(43.5)	1.9	182.5
Dividends declared on common stock	---	---	(103.0)	---	---	(103.0)
Issuance of common stock	0.1	77.7	---	---	---	77.8
Balance at September 30, 2009	$ 1.0	$ 879.7	$ 1,228.7	$ (57.2)	$ 19.1	$ 2,071.3

OGE ENERGY CORP.
CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2010	2009	2010	2009
Net income	$ 163.5	$ 137.5	$ 266.6	$ 226.0
Other comprehensive income (loss), net of tax				
Defined benefit pension plan and restoration of retirement income plan:				
	0.6	0.8	1.6	2.3

Amortization of deferred net loss, net of tax of $0.4 million, $0.5 million, $1.4 million and $1.6 million, respectively				
Amortization of prior service cost, net of tax of $0.1 million, $0, $0.1 million and $0.1 million, respectively	0.1	---	0.2	0.1
Defined benefit postretirement plans:				
Amortization of deferred net loss, net of tax of $0.2 million, $0.1 million, $0.2 million and $0.2 million, respectively	0.3	0.2	1.2	0.3
Amortization of deferred net transition obligation, net of tax of $0, $0.1 million, $0.1 million and $0.1 million, respectively	---	0.1	0.3	0.1
Amortization of prior service cost, net of tax of $0, $0, ($0.1) million and $0.1 million, respectively	---	---	(0.2)	0.1
Deferred commodity contracts hedging gains (losses), net of tax of ($4.5) million, $1.0 million, $1.7 million and ($29.5) million, respectively	(7.0)	1.5	2.6	(46.6)
Deferred hedging gains on interest rate swaps, net of tax of $0, $0, $0.1 million and $0.1 million, respectively	---	---	0.1	0.2
Other comprehensive income (loss), net of tax	(6.0)	2.6	5.8	(43.5)
Total comprehensive income	157.5	140.1	272.4	182.5
Less: Comprehensive income attributable to noncontrolling interest	(0.4)	(0.7)	(2.0)	(1.9)
Total comprehensive income attributable to OGE Energy	$ 157.1	$ 139.4	$ 270.4	$ 180.6

The accompanying Notes to Condensed Consolidated Financial Statements are an integral part hereof.

OGE ENERGY CORP.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)

1. Summary of Significant Accounting Policies

Organization

OGE Energy Corp. (“OGE Energy” and collectively, with its subsidiaries, the “Company”) is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central United States. The Company conducts these activities through four business segments: (i) electric utility, (ii) natural gas transportation and storage, (iii) natural gas gathering and processing and (iv) natural gas marketing. All significant intercompany transactions have been eliminated in consolidation.

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through Oklahoma Gas and Electric Company (“OG&E”) and are subject to regulation by the Oklahoma Corporation Commission (“OCC”), the Arkansas Public Service Commission (“APSC”) and the Federal Energy Regulatory Commission (“FERC”). OG&E was incorporated in 1902 under the laws of the Oklahoma Territory. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail natural gas business in 1928 and is no longer engaged in the natural gas distribution business.

Enogex LLC and its subsidiaries (“Enogex”) are providers of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting and storing natural gas. Most of Enogex’s natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex’s operations are organized into two business segments: (i) natural gas transportation and storage and (ii) natural gas gathering and processing. Also, Enogex holds a 50 percent ownership interest in the Atoka Midstream LLC joint venture (“Atoka”) through Enogex Atoka LLC, a wholly-owned subsidiary of Enogex Gathering & Processing LLC. The Company has consolidated 100 percent of Atoka in its consolidated financial statements as Enogex acts as the managing member of Atoka and has control over the operations of Atoka. Enogex is a Delaware single-member limited liability company.

On October 5, 2010, OGE Energy entered into an Investment Agreement with Bronco Midstream Holdings LLC (“Bronco”), a subsidiary of ArcLight Energy Partners Fund IV, L.P. (“ArcLight”), and Enogex Holdings LLC, an indirect wholly-owned subsidiary of OGE Energy (“Enogex Holdings”) pursuant to which Bronco agreed to make an initial equity investment in Enogex Holdings, the parent company of Enogex, in exchange for a 9.9 percent membership interest in Enogex Holdings. Prior to the closing of the transaction (which is expected to occur on November 1, 2010), 100 percent of the equity of OGE Energy Resources, Inc. (“OERI”), a natural gas marketing subsidiary currently owned by OGE Energy, will be contributed to Enogex.

The Company charges operating costs to its subsidiaries based on several factors. Operating costs directly related to specific subsidiaries are assigned to those subsidiaries. Where more than one subsidiary benefits from certain expenditures, the costs are shared between those subsidiaries receiving the benefits. Operating costs incurred for the benefit of all subsidiaries are allocated among the subsidiaries, either as overhead based primarily on labor costs or using the “Distrigas” method. The Distrigas method is a three-factor formula that uses an equal weighting of payroll, net operating revenues and gross property, plant and equipment. The Company adopted the Distrigas method in January 1996 as a result of a recommendation by the OCC Staff. The Company believes this method provides a reasonable basis for allocating common expenses.

Basis of Presentation

The Condensed Consolidated Financial Statements included herein have been prepared by the Company, without audit, pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and footnote disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles ("GAAP") have been condensed or omitted pursuant to such rules and regulations; however, the Company believes that the disclosures are adequate to prevent the information presented from being misleading.

In the opinion of management, all adjustments necessary to fairly present the consolidated financial position of the Company at September 30, 2010 and December 31, 2009, the results of its operations for the three and nine months ended

September 30, 2010 and 2009 and the results of its cash flows for the nine months ended September 30, 2010 and 2009, have been included and are of a normal recurring nature except as otherwise disclosed.

Due to seasonal fluctuations and other factors, the operating results for the three and nine months ended September 30, 2010 are not necessarily indicative of the results that may be expected for the year ending December 31, 2010 or for any future period. The Condensed Consolidated Financial Statements and Notes thereto should be read in conjunction with the audited Consolidated Financial Statements and Notes thereto included in the Company's Annual Report on Form 10-K for the year ended December 31, 2009 ("2009 Form 10-K").

Accounting Records

The accounting records of OG&E are maintained in accordance with the Uniform System of Accounts prescribed by the FERC and adopted by the OCC and the APSC. Additionally, OG&E, as a regulated utility, is subject to accounting principles for certain types of rate-regulated activities, which provide that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment.

OG&E records certain actual or anticipated costs and obligations as regulatory assets or liabilities if it is probable, based on regulatory orders or other available evidence, that the cost or obligation will be included in amounts allowable for recovery or refund in future rates.

The following table is a summary of OG&E's regulatory assets and liabilities at:

(In millions)	September 30, 2010	December 31, 2009
Regulatory Assets		
Current		
Fuel clause under recoveries	$ 0.9	$ 0.3
Miscellaneous (A)	0.9	2.2
Total Current Regulatory Assets	$ 1.8	$ 2.5
Non-Current		
Benefit obligations regulatory asset	$ 333.0	$ 357.8
Income taxes recoverable from customers, net	41.1	19.1
Deferred storm expenses	30.0	28.0
Unamortized loss on reacquired debt	15.6	16.5
Deferred pension plan expenses	14.7	18.1
Smart Grid	10.6	---
Red Rock deferred expenses	7.4	7.7
Miscellaneous	1.9	1.7
Total Non-Current Regulatory Assets	$ 454.3	$ 448.9
Regulatory Liabilities		
Current		
Fuel clause over recoveries	$ 68.0	$ 187.5
Miscellaneous (B)	17.6	7.3
Total Current Regulatory Liabilities	$ 85.6	$ 194.8

Non-Current		
Accrued removal obligations, net	$ 179.3	$ 168.2
Miscellaneous	5.8	---
Total Non-Current Regulatory Liabilities	$ 185.1	$ 168.2

(A) Included in Other Current Assets on the Condensed Consolidated Balance Sheets.
(B) Included in Other Current Liabilities on the Condensed Consolidated Balance Sheets.

For a discussion of regulatory assets related to OG&E's Smart Grid program, see Note 14.

Management continuously monitors the future recoverability of regulatory assets. When in management's judgment future recovery becomes impaired, the amount of the regulatory asset is adjusted, as appropriate. If the Company were required to discontinue the application of accounting principles for certain types of rate-regulated activities for some or all of its operations, it could result in writing off the related regulatory assets; the financial effects of which could be significant.

Deferred Revenues

The Company records deferred revenue when it receives consideration from a third party before achieving certain criteria that must be met for revenue to be recognized in accordance with GAAP.

In January 2009, Enogex entered into a Facility Construction, Ownership and Operating Agreement for the installation of transportation and compression facilities necessary to provide gas delivery service to a new natural gas-fired electric generation facility near Pryor, Oklahoma. Construction of the required facilities was completed during August 2010. Aid in Construction payments of $37.2 million received in excess of construction costs have been recognized as Deferred Revenues on the Company's Condensed Consolidated Balance Sheet and will be amortized on a straight-line basis of $1.2 million per year over the life of the related Intrastate Firm Transportation Services agreement under which service will commence in June 2011.

Reclassifications

Certain prior year amounts have been reclassified on the Condensed Consolidated Statements of Income and Condensed Consolidated Balance Sheet to conform to the 2010 presentation primarily related to the presentation of regulatory assets and liabilities. Certain prior year amounts have been reclassified on the Condensed Consolidated Statement of Cash Flows to conform to the 2010 presentation related to a customer's reimbursement of Enogex's costs related to the construction of a transportation pipeline in 2009 and 2010 as well as a change in the presentation of regulatory assets and liabilities.

2. Investment Agreement with ArcLight

On October 5, 2010, OGE Energy entered into an Investment Agreement with Bronco and Enogex Holdings pursuant to which Bronco agreed to make an initial equity investment in Enogex Holdings, the parent company of Enogex, in an amount equal to $183,150,000 in exchange for a 9.9 percent membership interest in Enogex Holdings. This transaction will be accounted for as an equity transaction for entities under common control and no gain or loss will be recognized in the Company's Condensed Consolidated Financial Statements. OGE Energy will continue to consolidate 100 percent of Enogex in its consolidated financial statements as OGE Energy has a controlling financial interest over the operations of Enogex. Bronco's ownership interest will be presented as a noncontrolling interest in the Company's Condensed Consolidated Financial Statements. Prior to the closing of the transaction, 100 percent of the equity of OERI, which is currently owned by OGE Energy, will be contributed to Enogex.

Consummation of the transaction is conditioned on certain customary closing conditions. However, no regulatory approvals are required to close the transaction. Pending closing of the transaction, which is anticipated to occur on November 1, 2010, the Company has agreed to customary interim operating covenants relating to the conduct of Enogex's business. If the transaction closes, the Company and Bronco have agreed to indemnify each other for breaches of representations, warranties and covenants contained in the Investment Agreement, and, in the case of the Company, for certain tax matters related to the Company, in each case subject to customary thresholds and survival periods.

Upon consummation of the transactions contemplated by the Investment Agreement, OGE Enogex Holdings LLC, a wholly-owned subsidiary of the Company and the parent of Enogex Holdings ("OGE Holdings"), and Bronco will enter into an Amended and Restated Limited Liability Company Agreement of Enogex Holdings ("LLC Agreement").

Pursuant to the LLC Agreement, OGE Holdings' and Bronco's rights to designate directors to the board of directors of Enogex Holdings ("Enogex Holdings Board") will be determined by percentage ownership. OGE Holdings will initially be entitled to designate three directors, and Bronco will initially be entitled to designate one director. Bronco will also be entitled, at various ownership thresholds, to certain special board approval rights with respect to certain significant actions taken by Enogex Holdings.

Until Bronco owns 50 percent of the equity of Enogex Holdings, Bronco will fund capital contributions in an amount higher than its proportionate interest. Specifically, Bronco will fund between 50 percent and 90 percent of required capital contributions during that period. The remainder of the required capital contributions (i.e., between 10 percent and 50 percent) will be funded by OGE Holdings. Until the beginning of 2012, the per unit equity price to be paid will be equal to the price paid by Bronco under the Investment Agreement. On and after January 1, 2012, the equity price per unit will be based on the equity value of Enogex Holdings. Subject to certain adjustments, including for material acquisitions, equity value will be calculated as 9.0 or 9.5 times trailing twelve-month Earnings before Interest, Income Taxes and Depreciation and Amortization, depending on Bronco's ownership interest and whether the project has already been identified by Enogex.

Pursuant to the LLC Agreement, Enogex Holdings will make minimum quarterly distributions equal to the amount of cash required to cover the members' respective anticipated tax liabilities plus $12,500,000, to be distributed in proportion to each member's percentage ownership interest.

Under the terms of the LLC Agreement, each member and its affiliates are prohibited from independently pursuing a transaction in which a portion of the relevant assets are located in a designated core operating area ("Core Operating Area"), subject to certain exceptions. In addition, each member and its affiliates are prohibited from independently pursuing a transaction in which a portion of the relevant assets are located in a designated "area of mutual interest" ("AMI") unless (i) in the case of Bronco, its ownership interest is less than 5 percent, (ii) the transaction falls within a defined category of passive financial investments, (iii) the proposed transaction has been disapproved by Enogex Holdings or (iv) the fair market value of the assets located in the AMI constitutes less than 50 percent of the total fair market value of the assets involved in the transaction. A member permitted to pursue a transaction independently pursuant to the foregoing is not required to offer the assets associated with such transaction to Enogex Holdings.

3. Fair Value Measurements

The classification of the Company's fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. GAAP establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to quoted prices in active markets for identical unrestricted assets or liabilities (Level 1) and the lowest priority given to unobservable inputs (Level 3). Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The three levels defined in the fair value hierarchy and examples of each are as follows:

Level 1 inputs are quoted prices in active markets for identical unrestricted assets or liabilities that are accessible at the measurement date. An example of instruments that may be classified as Level 1 are futures transactions for energy commodities traded on the New York Mercantile Exchange ("NYMEX").

Level 2 inputs are inputs other than quoted prices in active markets included within Level 1 that are either directly or indirectly observable at the reporting date for the asset or liability for substantially the full term of the asset or liability. Level 2 inputs include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active. An example of instruments that may be classified as Level 2 includes energy commodity purchase or sales transactions in a market such that the pricing is closely related to the NYMEX pricing.

Level 3 inputs are prices or valuation techniques for the asset or liability that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity). Unobservable inputs reflect the reporting entity's own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk). An example of instruments that may be classified as Level 3 includes energy commodity purchase or sales transactions of a longer duration or in an inactive market such that there are no closely related markets in which quoted prices are available.

The Company utilizes the market approach in determining the fair value of its derivative positions by using either NYMEX published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX published market prices may be considered Level 1 if they are settled through a NYMEX clearing broker account with daily margining. Over-the-counter derivatives with NYMEX based prices are considered Level 2 due to the impact of counterparty credit risk. Valuations based on independent broker pricing or broker/dealer valuations may be classified as Level 2 only to the extent they may be validated by an additional source of independent market data for an identical or closely related active market. Otherwise, they are considered Level 3.

The impact to the fair value of derivatives due to credit risk is calculated using the probability of default based on Standard & Poor's Ratings Services ("Standard & Poor's") and/or internally generated ratings. The fair value of derivative assets is adjusted for credit risk. The fair value of derivative liabilities is adjusted for credit risk only if the impact is deemed material.

Contracts with Master Netting Arrangements

Fair value amounts recognized for forward, interest rate swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Condensed Consolidated Balance Sheets. The Company has presented the fair values of its derivative contracts under master netting agreements using a net fair value presentation.

The following tables summarize the Company's assets and liabilities that are measured at fair value on a recurring basis at September 30, 2010 and December 31, 2009 as well as reconcile the Company's commodity contracts fair value to Price Risk Management ("PRM") Assets and Liabilities on the Company's Condensed Consolidated Balance Sheet at September 30, 2010 and December 31, 2009.

	September 30, 2010			
(In millions)	Commodity Contracts		Gas Imbalances (A)	
	Assets	Liabilities	Assets	Liabilities (B)
Quoted market prices in active market for identical assets (Level 1)	$ 35.9	$ 34.3	$ ---	$ ---
Significant other observable inputs (Level 2)	6.9	42.9	3.2	3.2
Significant unobservable inputs (Level 3)	26.9	3.2	---	---
Total fair value	69.7	80.4	3.2	3.2
Netting adjustments	(65.9)	(64.7)	---	---
Total	$ 3.8	$ 15.7	$ 3.2	$ 3.2

	December 31, 2009			
(In millions)	Commodity Contracts		Gas Imbalances (A)	
	Assets	Liabilities	Assets	Liabilities (B)
Quoted market prices in active market for identical assets (Level 1)	$ 16.1	$ 13.3	$ ---	$ ---
Significant other observable inputs (Level 2)	6.2	49.8	3.2	8.0
Significant unobservable inputs (Level 3)	49.0	14.7	---	---
Total fair value	71.3	77.8	3.2	8.0
Netting adjustments	(65.2)	(63.5)	---	---
Total	$ 6.1	$ 14.3	$ 3.2	$ 8.0

(A) The Company uses the market approach to fair value its gas imbalance assets and liabilities, using an average of the Inside FERC Gas Market Report for Panhandle Eastern Pipe Line Co. (Texas, Oklahoma Mainline), ONEOK (Oklahoma) and ANR Pipeline (Oklahoma) indices.

(B) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of $7.8 million and $4.0 million at September 30, 2010 and December 31, 2009, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

The following table summarizes the Company's assets and liabilities that are measured at fair value on a recurring basis using significant unobservable inputs (Level 3).

	Commodity Contracts			
	Assets		Liabilities	
(In millions)	2010	2009	2010	2009
Balance at January 1	$ 49.0	$ 121.2	$ 14.7	$ ---
Total gains or losses				
Included in other comprehensive income	(3.9)	(11.1)	(5.1)	---
Purchases, issuances, sales and settlements				
Settlements	(4.1)	(4.5)	(1.4)	---
Balance at March 31	41.0	105.6	8.2	---
Total gains or losses				
Included in other comprehensive income	7.2	(34.4)	(3.7)	---
Purchases, issuances, sales and settlements				
Purchases	---	---	---	1.8
Settlements	(6.1)	(3.9)	(2.7)	---
Balance at June 30	42.1	67.3	1.8	1.8
Total gains or losses				
Included in other comprehensive income	(8.5)	(2.5)	2.3	(0.4)
Purchases, issuances, sales and settlements				
Settlements	(6.7)	(1.4)	(0.9)	---
Balance at September 30	$ 26.9	$ 63.4	$ 3.2	$ 1.4
Amount of total gains or losses included in earnings attributable to the change in unrealized gains or losses relating to assets and liabilities held at September 30	$ ---	$ ---	$ ---	$ ---

Gains and losses (realized and unrealized) included in earnings for the three and nine months ended September 30, 2010 and 2009 attributable to the change in unrealized gains or losses relating to assets and liabilities held at September 30, 2010 and 2009, if any, are reported in Operating Revenues.

The following table summarizes the fair value and carrying amount of the Company's financial instruments, including derivative contracts related to the Company's PRM activities at September 30, 2010 and December 31, 2009.

	September 30, 2010		December 31, 2009	
(In millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Price Risk Management Assets				
Energy Derivative Contracts	$ 3.8	$ 3.8	$ 6.1	$ 6.1
Price Risk Management Liabilities				
Energy Derivative Contracts	$ 15.7	$ 15.7	$ 14.3	$ 14.3
Long-Term Debt				
OG&E Senior Notes	$ 1,655.0	$ 1,958.1	$ 1,406.4	$ 1,492.1

OGE Energy Senior Notes	99.6	109.6	99.5	102.6
OG&E Industrial Authority Bonds	135.4	135.4	135.4	135.4
Enogex Senior Notes	447.8	499.7	736.8	746.7
Enogex Revolving Credit Agreement	35.0	35.0	---	---

The carrying value of the financial instruments on the Condensed Consolidated Balance Sheets not otherwise discussed above approximates fair value except for long-term debt which is valued at the carrying amount. The valuation of the Company's energy derivative contracts was determined generally based on quoted market prices. However, in certain instances where market quotes are not available, other valuation techniques or models are used to estimate market values. The valuation of instruments also considers the credit risk of the counterparties. The fair value of the Company's long-term debt is based on quoted market prices and estimates of current rates available for similar issues with similar maturities.

4. Derivative Instruments and Hedging Activities

The Company is exposed to certain risks relating to its ongoing business operations. The primary risks managed using derivatives instruments are commodity price risk and interest rate risk. The Company is also exposed to credit risk in its business operations.

Commodity Price Risk

The Company primarily uses forward physical contracts, commodity price swap contracts and commodity price option features to manage the Company's commodity price risk exposures. Commodity derivative instruments used by the Company are as follows:

- natural gas liquids ("NGL") put options and NGLs swaps are used to manage Enogex's NGLs exposure associated with its processing agreements;
- natural gas swaps are used to manage Enogex's keep-whole natural gas exposure associated with its processing operations and Enogex's natural gas exposure associated with operating its gathering, transportation and storage assets;
- natural gas futures and swaps and natural gas commodity purchases and sales are used to manage OERI's natural gas exposure associated with its storage and transportation contracts; and
- natural gas futures and swaps, natural gas options and natural gas commodity purchases and sales are used to manage OERI's marketing and trading activities.

Normal purchases and normal sales contracts are not recorded in PRM Assets or Liabilities in the Condensed Consolidated Balance Sheets and earnings recognition is recorded in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales treatment to: (i) commodity contracts for the purchase and sale of natural gas used in or produced by its operations, (ii) commodity contracts for the sale of NGLs produced by Enogex's gathering and processing business, (iii) electric power contracts by OG&E and (iv) fuel procurement by OG&E.

The Company recognizes its non-exchange traded derivative instruments as PRM Assets or Liabilities in the Condensed Consolidated Balance Sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. Exchange traded transactions are settled on a net basis daily through margin accounts with a clearing broker and, therefore, are recorded at fair value on a net basis in Other Current Assets in the Condensed Consolidated Balance Sheets.

Interest Rate Risk

The Company's exposure to changes in interest rates primarily relates to short-term variable debt and commercial paper. The Company manages its interest rate exposure by limiting its variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. The Company utilizes interest rate derivatives to alter interest rate exposure in an attempt to reduce interest expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Credit Risk

The Company is exposed to certain credit risks relating to its ongoing business operations. Credit risk includes the risk that counterparties that owe the Company money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, the Company may be forced to enter into alternative arrangements. In that event, the Company's financial results could be adversely affected and the Company could incur losses.

Cash Flow Hedges

For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of Accumulated Other Comprehensive Income and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portion of a derivative's change in fair value or hedge components excluded from the assessment of effectiveness is recognized currently in earnings. The Company measures the ineffectiveness of commodity cash flow hedges using the change in fair value method whereby the change in the expected future cash flows designated as the hedge transaction are compared to the change in fair value of the hedging instrument. Forecasted transactions, which are designated as the hedged transaction in a cash flow hedge, are regularly evaluated to assess whether they continue to be probable of occurring. If the forecasted transactions are no longer probable of occurring, hedge accounting will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings.

The Company designates as cash flow hedges derivatives used to manage commodity price risk exposure for Enogex's NGLs volumes and corresponding keep-whole natural gas resulting from its natural gas processing contracts (processing hedges) and natural gas positions resulting from its natural gas gathering and processing, pipeline and storage operations (operational gas hedges). Enogex's cash flow hedging activity at September 30, 2010 covers the period from October 1, 2010 through December 31, 2011. The Company also designates as cash flow hedges certain derivatives used to manage natural gas commodity exposure for certain natural gas storage inventory positions at OERI. OERI's cash flow hedging activity extends through February 28, 2011.

Fair Value Hedges

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 loss or gain on the hedged item attributable to the hedge risk are recognized currently in earnings. The Company includes the gain or loss on the hedged items in Operating Revenues as the offsetting loss or gain on the related hedging derivative.

At September 30, 2010 and December 31, 2009, the Company had no derivative instruments that were designated as fair value hedges.

Derivatives Not Designated As Hedging Instruments

Derivative instruments not designated as hedging instruments are utilized in OERI's asset management, marketing and trading activities and also include contracts formerly designated as cash flow hedges of Enogex's NGLs, keep-whole natural gas and operational storage natural gas exposures. A portion of Enogex's processing agreements, which were previously under keep-whole arrangements, were converted to fee-based arrangements. As a result, effective June 30, 2009 Enogex de-designated a portion of these derivatives and entered into offsetting derivatives to close the positions. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized currently in earnings.

Quantitative Disclosures Related to Derivative Instruments

At September 30, 2010, the Company had the following derivative instruments that were designated as cash flow hedges.

(In millions)	Gross Notional Volume (A)	
	2010	2011
Enogex processing hedges		
NGLs sales	0.4	1.3
Natural gas purchases	1.6	5.2
Enogex operational gas hedges		
Natural gas sales	0.5	---
OERI hedges		
Natural gas sales	---	0.9

(A) Natural gas in million British thermal unit ("MMBtu"); NGLs in barrels.

At September 30, 2010, the Company had the following derivative instruments that were not designated as hedging instruments.

(In millions)	Gross Notional Volume (A)	
	Purchases	Sales
Natural Gas (B)		
Physical (C)(D)	20.1	59.1
Fixed Swaps/Futures	44.8	44.7
Options	26.3	24.1
Basis Swaps	16.4	12.7
NGLs (B)		
Fixed Swaps/Futures	0.2	0.2

(A) Natural gas in MMBtu; NGLs in barrels.
(B) 88 percent of the natural gas contracts have durations of one year or less, seven percent have durations of more than one year and less than two years and five percent have durations of more than two years. The NGLs contracts all settle by December 31, 2010.
(C) Of the natural gas physical purchases and sales volumes not designated as hedges, the majority are priced based on a monthly or daily index and the fair value is subject to little or no market price risk.
(D) Natural gas physical sales volumes exceed natural gas physical purchase volumes due to the marketing of natural gas volumes purchased via Enogex's processing contracts, which are not derivative instruments and are excluded from the table above.

Balance Sheet Presentation Related to Derivative Instruments

The fair value of the derivative instruments that are presented in the Company's Condensed Consolidated Balance Sheet at September 30, 2010 are as follows:

		Fair Value	
Instrument	Balance Sheet Location	Assets	Liabilities
		(In millions)	
Derivatives Designated as Hedging Instruments			
NGLs			
Financial Options	Current PRM	$ 19.7	$ ---
	Non-Current PRM	5.3	---
Financial Futures/Swaps	Current PRM	---	1.3
Natural Gas			
Financial Futures/Swaps	Current PRM	---	29.2
	Non-Current PRM	---	7.0
	Other Current Assets	2.4	0.1
Total		$ 27.4	$ 37.6
Derivatives Not Designated as Hedging Instruments			
NGLs			
Financial Futures/Swaps (A)	Current PRM	$ 2.0	$ 1.9
Natural Gas			
Financial Futures/Swaps (B)	Current PRM	2.2	4.4
	Other Current Assets	33.7	34.5
Physical Purchases/Sales	Current PRM	3.1	0.7
	Non-Current PRM	0.4	0.1
Financial Options	Other Current Assets	0.9	1.2
Total		$ 42.3	$ 42.8
Total Gross Derivatives (C)		$ 69.7	$ 80.4

(A) The entire fair value of Financial Futures/Swaps – NGLs not designated as hedging instruments consists of derivatives that were previously designated as hedging instruments and subsequently de-designated with offsetting derivatives to close the hedge positions.

(B) The fair value of Financial Futures/Swaps – Natural Gas not designated as hedging instruments includes derivatives that were previously designated as hedging instruments and subsequently de-designated with offsetting derivatives to close the hedge positions. The referenced derivatives had a fair value as presented in the table above in Current Assets of $1.8 million and Current Liabilities of $4.2 million.

(C) See reconciliation of the Company's total derivatives fair value to the Company's Condensed Consolidated Balance Sheet at September 30, 2010 (see Note 3).

The fair value of the derivative instruments that are presented in the Company's Condensed Consolidated Balance Sheet at December 31, 2009 are as follows:

Instrument	Balance Sheet Location	Fair Value Assets	Fair Value Liabilities
		(In millions)	
Derivatives Designated as Hedging Instruments			
NGLs			
Financial Options	Current PRM	$ 16.4	$ ---
	Non-Current PRM	23.4	---
Financial Futures/Swaps	Current PRM	---	6.1
Natural Gas			
Financial Futures/Swaps	Current PRM	---	14.8
	Non-Current PRM	---	19.7
	Other Current Assets	4.6	1.2
Total		$ 44.4	$ 41.8
Derivatives Not Designated as Hedging Instruments			
NGLs			
Financial Futures/Swaps (A)	Current PRM	$ 9.2	$ 8.6
Natural Gas			
Financial Futures/Swaps (B)	Current PRM	3.6	12.3
	Non-Current PRM	---	0.1
	Other Current Assets	11.8	13.6
Physical Purchases/Sales	Current PRM	0.8	0.6
	Non-Current PRM	0.6	---
Financial Options	Other Current Assets	0.9	0.8
Total		$ 26.9	$ 36.0
Total Gross Derivatives (C)		$ 71.3	$ 77.8

(A) The entire fair value of Financial Futures/Swaps – NGLs not designated as hedging instruments consists of derivatives that were previously designated as hedging instruments and subsequently de-designated with offsetting derivatives to close the hedge positions.

(B) The fair value of Financial Futures/Swaps – Natural Gas not designated as hedging instruments includes derivatives that were previously designated as hedging instruments and subsequently de-designated with offsetting derivatives to close the hedge positions. The referenced derivatives had a fair value as presented in the table above in Current Assets of $2.9 million and Current Liabilities of $11.7 million.

(C) See reconciliation of the Company's total derivatives fair value to the Company's Condensed Consolidated Balance Sheet at December 31, 2009 (see Note 3).

Income Statement Presentation Related to Derivative Instruments

The following table presents the effect of derivative instruments on the Company's Condensed Consolidated Statement of Income for the three months ended September 30, 2010.

Derivatives in Cash Flow Hedging Relationships

(In millions)	Amount Recognized in OCI (A)	Amount Reclassified from Accumulated OCI into Income	Amount Recognized in Income
NGLs Financial Options	$ (12.2)	$ 1.5	$ ---
NGLs Financial Futures/Swaps	(1.2)	(0.3)	---
Natural Gas Financial Futures/Swaps	(5.5)	(6.7)	---
Total	$ (18.9)	$ (5.5)	$ ---

(A) The estimated net amount of gains or losses included in Accumulated Other Comprehensive Income at September 30, 2010 that is expected to be reclassified into income within the next 12 months is a loss of $14.5 million.

Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income
Natural Gas Physical Purchases/Sales	$ (2.3)
Natural Gas Financial Futures/Swaps	0.6
Total	$ (1.7)

The following table presents the effect of derivative instruments on the Company's Condensed Consolidated Statement of Income for the three months ended September 30, 2009.

Derivatives in Cash Flow Hedging Relationships

(In millions)	Amount Recognized in OCI	Amount Reclassified from Accumulated OCI into Income	Amount Recognized in Income
NGLs Financial Options	$ (2.7)	$ 0.3	$ ---
NGLs Financial Futures/Swaps	(0.8)	2.2	---
Natural Gas Financial Futures/Swaps	---	(8.3)	0.1
Total	$ (3.5)	$ (5.8)	$ 0.1

Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income

Natural Gas Physical Purchases/Sales	$	(8.3)
Natural Gas Financial Futures/Swaps		4.3
Total	$	(4.0)

The following table presents the effect of derivative instruments on the Company's Condensed Consolidated Statement of Income for the nine months ended September 30, 2010.

Derivatives in Cash Flow Hedging Relationships

(In millions)		Amount Recognized in OCI (A)		Amount Reclassified from Accumulated OCI into Income		Amount Recognized in Income
NGLs Financial Options	$	(1.2)	$	2.0	$	---
NGLs Financial Futures/Swaps		2.1		(2.2)		---
Natural Gas Financial Futures/Swaps		(15.4)		(18.7)		0.1
Total	$	(14.5)	$	(18.9)	$	0.1

(A) The estimated net amount of gains or losses included in Accumulated Other Comprehensive Income at September 30, 2010 that is expected to be reclassified into income within the next 12 months is a loss of $14.5 million.

Derivatives Not Designated as Hedging Instruments

(In millions)		Amount Recognized in Income
Natural Gas Physical Purchases/Sales	$	(6.4)
Natural Gas Financial Futures/Swaps		0.8
Total	$	(5.6)

The following table presents the effect of derivative instruments on the Company's Condensed Consolidated Statement of Income for the nine months ended September 30, 2009.

Derivatives in Cash Flow Hedging Relationships

(In millions)		Amount Recognized in OCI		Amount Reclassified from Accumulated OCI into Income		Amount Recognized in Income
NGLs Financial Options	$	(36.6)	$	3.2	$	---
NGLs Financial Futures/Swaps		(26.0)		12.4		---
Natural Gas Financial Futures/Swaps		(17.0)		(19.4)		(0.2)
Total	$	(79.6)	$	(3.8)	$	(0.2)

Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income

Natural Gas Physical Purchases/Sales	$	(18.8)
Natural Gas Financial Futures/Swaps		12.7
NGLs Financial Futures/Swaps		(0.2)
Total	$	(6.3)

For derivatives designated as cash flow hedges in the tables above, amounts reclassified from Accumulated Other Comprehensive Income into income (effective portion) and amounts recognized in income (ineffective portion) for the three and nine months ended September 30, 2010 and 2009, if any, are reported in Operating Revenues. For derivatives not designated as hedges in the tables above, amounts recognized in income for the three and nine months ended September 30, 2010 and 2009, if any, are reported in Operating Revenues.

Credit-Risk Related Contingent Features in Derivative Instruments

In the event Moody's Investors Service or Standard & Poor's were to lower the Company's senior unsecured debt rating to a below investment grade rating, at September 30, 2010, the Company would have been required to post $13.7 million of cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position at September 30, 2010. In addition, the Company could be required to provide additional credit assurances in future dealings with third parties, which could include letters of credit or cash collateral.

5. Stock-Based Compensation

The Company recorded compensation expense of $2.6 million pre-tax ($1.6 million after tax, or $0.02 per basic and diluted share) and $6.5 million pre-tax ($4.0 million after tax, or $0.04 per basic and diluted share), respectively, during the three and nine months ended September 30, 2010 related to the Company's performance units. The Company recorded compensation expense of $1.6 million pre-tax ($1.0 million after tax, or $0.01 per basic and diluted share) and $4.9 million pre-tax ($3.0 million after tax, or $0.03 per basic and diluted share), respectively, during the three and nine months ended September 30, 2009 related to the Company's performance units.

The Company issues new shares to satisfy stock option exercises and payouts of earned performance units. During the three and nine months ended September 30, 2010, there were 22,900 shares and 218,033 shares, respectively, of new common stock issued pursuant to the Company's compensation plans related to exercised stock options and payouts of earned performance units. The Company received $0.5 million and $2.1 million, respectively, during the three months ended September 30, 2010 and 2009, and $3.0 million and $2.1 million, respectively, during the nine months ended September 30, 2010 and 2009, related to exercised stock options.

There was no restricted stock awarded during the three months ended September 30, 2010. The Company awarded 23,775 shares of restricted stock during the nine months ended September 30, 2010. There were 1,684 shares of restricted stock forfeited during both the three and nine months ended September 30, 2010.

6. Accumulated Other Comprehensive Income (Loss)

The following table summarizes the components of accumulated other comprehensive loss at September 30, 2010 and December 31, 2009 attributable to OGE Energy. At both September 30, 2010 and December 31, 2009, there was no accumulated other comprehensive loss related to Enogex's noncontrolling interest in Atoka.

(In millions)	September 30, 2010	December 31, 2009
Defined benefit pension plan and restoration of retirement income plan:		
Net loss	$(38.4)	$(40.0)
Prior service cost	(0.5)	(0.7)
Defined benefit postretirement plans:		
Net loss	(9.5)	(10.7)
Net transition obligation	(0.1)	(0.4)
Prior service cost	(0.2)	---
Deferred commodity contacts hedging losses	(19.1)	(21.7)
Deferred hedging losses on interest rate swaps	(1.1)	(1.2)
Total accumulated other comprehensive loss	$(68.9)	$(74.7)

7. Income Taxes

The Company files consolidated income tax returns in the U.S. Federal jurisdiction and various state jurisdictions. With few exceptions, the Company is no longer subject to U.S. Federal tax examinations by tax authorities for years prior to 2006 or state and local tax examinations by tax authorities for years prior to 2002. Income taxes are generally allocated to each company in the affiliated group based on its stand-alone taxable income or loss. Federal investment tax credits previously claimed on electric utility property have been deferred and are being amortized to income over the life of the related property. The Company continues to amortize its Federal investment tax credits on a ratable basis throughout the year. OG&E earns both Federal and Oklahoma state tax credits associated with the production from its wind farms. In addition, OG&E and Enogex earn Oklahoma state tax credits associated with their investments in electric generating and natural gas processing facilities which further reduce the Company's effective tax rate.

The Company had a Federal tax net operating loss for 2009 primarily caused by the accelerated tax depreciation provisions contained within the American Recovery and Reinvestment Act of 2009 ("ARRA"). ARRA allowed a current deduction for 50 percent of the cost of certain property placed into service during 2009. This tax loss resulted in a $68 million current income tax receivable related to the 2009 tax year. On November 6, 2009, the Worker, Homeownership, and Business Assistance Act of 2009 was signed into law by the President. This new law provided for a five-year carry back of net operating losses incurred in 2008 or 2009. This expanded carryback period enabled the Company to carry back the entire 2009 tax loss. A carryback claim was filed in March 2010 and a refund of $68 million was received by the Company in April 2010.

In June 2010, new legislation was passed in Oklahoma that created a moratorium, from July 1, 2010 through June 30, 2012, on 30 income tax credits. For income tax purposes, credits affected by the moratorium may not be claimed for any event, transaction, investment, expenditure or other act for which the credits would otherwise be allowable. During this two-year window, affected credits generated by the Company will be deferred and utilized at a time after the moratorium expires. For financial accounting purposes, the Company will receive the benefits in the future as the credits do not expire if they are not utilized in the period they are generated.

In September 2010, the Small Business Jobs and Credit Act of 2010 was signed into law, which allows the Company to record a current income tax deduction for 50 percent of the cost of certain property placed into service during 2010 as a result of the accelerated tax depreciation provisions within the new law. As a result, for income tax purposes, the Company expects minimal Federal taxable income for 2010. For financial accounting purposes, the Company recorded an increase in its Non-Current Deferred Income Taxes Liability at September 30, 2010 on the Company's Condensed Consolidated Balance Sheet to recognize the financial statement impact of this new law.

Medicare Part D Subsidy

On March 23, 2010, the Patient Protection and Affordable Care Act of 2009 (the "Patient Protection Act") was signed into law, and, on March 30, 2010, the Health Care and Education Reconciliation Act of 2010 (the "Reconciliation Act" and, together with Patient Protection Act, the "Acts"), which makes various amendments to certain aspects of the Patient Protection Act, was signed into law. The Acts effectively change the tax treatment of federal subsidies paid to sponsors of retiree health benefit plans that provide prescription drug benefits that are at least actuarially equivalent to the corresponding benefits provided under Medicare Part D.

The federal subsidy paid to employers was introduced as part of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003 (the "Medicare Act"). The Company has been recognizing the federal subsidy since 2005 related to certain retiree prescription drug plans that were determined to be actuarially equivalent to the benefit provided under Medicare Part D. Under the Medicare Act, the federal subsidy does not reduce an employer's income tax deduction for the costs of providing such prescription drug plans nor is it subject to income tax individually.

Under the Acts, beginning in 2013 an employer's income tax deduction for the costs of providing Medicare Part D-equivalent prescription drug benefits to retirees will be reduced by the amount of the federal subsidy. Under GAAP, any impact from a change in tax law must be recognized in earnings in the period enacted regardless of the effective date. As retiree healthcare liabilities and related tax impacts are already reflected in the Company's Condensed Consolidated Financial Statements, the Company recognized a one-time, non-cash charge of $11.4 million, or $0.11 per diluted share, during the quarter ended March 31, 2010 for the write-off of previously recognized tax benefits relating to Medicare Part D subsidies to reflect the change in the tax treatment of the federal subsidy.

8. Common Equity

Automatic Dividend Reinvestment and Stock Purchase Plan

In November 2008, the Company filed a Form S-3 Registration Statement to register 5,000,000 shares of the Company's common stock pursuant to the Company's Automatic Dividend Reinvestment and Stock Purchase Plan ("DRIP/DSPP"). The Company issued 82,550 shares and 272,236 shares, respectively, of common stock under its DRIP/DSPP during the three and nine months ended September 30, 2010 and received proceeds of $3.3 million and $10.6 million, respectively. The Company may, from time to time, issue additional shares under its DRIP/DSPP to fund capital requirements or working capital needs.

At September 30, 2010, there were 2,720,508 shares of unissued common stock reserved for issuance under the Company's DRIP/DSPP.

Earnings Per Share

Outstanding shares for purposes of basic and diluted earnings per average common share were calculated as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2010	2009	2010	2009
Average Common Shares Outstanding				
Basic average common shares outstanding	97.4	96.7	97.3	96.0
Effect of dilutive securities:				
Contingently issuable shares (performance units)	1.6	1.0	1.5	0.9
Diluted average common shares outstanding	99.0	97.7	98.8	96.9
Anti-dilutive shares excluded from EPS calculation	---	---	---	---

9. Long-Term Debt

At September 30, 2010, the Company was in compliance with all of its debt agreements.

OG&E has three series of variable-rate industrial authority bonds (the "Bonds") with optional redemption provisions that allow the holders to request repayment of the Bonds at various dates prior to the maturity. The Bonds, which can be tendered at the option of the holder during the next 12 months, are as follows:

SERIES	DATE DUE	AMOUNT (In millions)
0.30% - 0.50%	Garfield Industrial Authority, January 1, 2025	$ 47.0
0.35% - 0.52%	Muskogee Industrial Authority, January 1, 2025	32.4
0.33% - 0.55%	Muskogee Industrial Authority, June 1, 2027	56.0
Total (redeemable during next 12 months)		$135.4

All of these Bonds are subject to an optional tender at the request of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to the date of purchase. The bond holders, on any business day, can request repayment of the Bond by delivering an irrevocable notice to the tender agent stating the principal amount of the Bond, payment instructions for the purchase price and the business day the Bond is to be purchased. The repayment option may only be exercised by the holder of a Bond for the principal amount. When a tender notice has been received by the trustee, a third party remarketing agent for the Bonds will attempt to remarket any Bonds tendered for purchase. This process occurs once per week. Since the original issuance of these series of Bonds in 1995 and 1997, the remarketing agent has successfully remarketed all tendered bonds. If the remarketing agent is unable to remarket any such Bonds, OG&E is obligated to repurchase such unremarketed Bonds. As OG&E has both the intent and ability to refinance the Bonds on a long-term basis and such ability is supported by an ability to consummate the refinancing, the Bonds are classified as long-term debt in the Company's Condensed Consolidated Financial Statements. OG&E believes that it has sufficient liquidity to meet these obligations.

10. Short-Term Debt and Credit Facilities

The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The short-term debt balance was $224.0 million and $175.0 million at

September 30, 2010 and December 31, 2009, respectively. The following table provides information regarding the Company's revolving credit agreements and available cash at September 30, 2010.

Revolving Credit Agreements and Available Cash

Entity	Aggregate Commitment	Amount Outstanding (A)	Weighted-Average Interest Rate	Maturity
	(In millions)			
OGE Energy (B)	$ 596.0	$ 224.0	0.37% (D)	December 6, 2012
OG&E (C)	389.0	9.5	0.14% (D)	December 6, 2012
Enogex (E)	250.0	35.0	0.57% (D)	March 31, 2013
	1,235.0	268.5	0.39%	
Cash	8.5	N/A	N/A	N/A
Total	$ 1,243.5	$ 268.5	0.39%	

(A) Includes direct borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit at September 30, 2010.
(B) This bank facility is available to back up OGE Energy's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility. At September 30, 2010, there were no outstanding borrowings under this revolving credit agreement and $224.0 million in outstanding commercial paper borrowings.
(C) This bank facility is available to back up OG&E's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility. At September 30, 2010, there was $9.5 million supporting letters of credit. There were no outstanding borrowings under this revolving credit agreement and no outstanding commercial paper borrowings at September 30, 2010.
(D) Represents the weighted-average interest rate for the outstanding borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit.
(E) This bank facility is available to provide revolving credit borrowings for Enogex. As Enogex's credit agreement matures on March 31, 2013, borrowings thereunder are classified as long-term debt in the Company's Condensed Consolidated Balance Sheets.

OGE Energy's and OG&E's ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruptions. Pricing grids associated with the Company's credit facilities could cause annual fees and borrowing rates to increase if an adverse ratings impact occurs. The impact of any future downgrade could include an increase in the costs of the Company's short-term borrowings, but a reduction in the Company's credit ratings would not result in any defaults or accelerations. Any future downgrade of the Company could also lead to higher long-term borrowing costs and, if below investment grade, would require the Company to post cash collateral or letters of credit.

Unlike OGE Energy and Enogex, OG&E must obtain regulatory approval from the FERC in order to borrow on a short-term basis. OG&E has the necessary regulatory approvals to incur up to $800 million in short-term borrowings at any one time for a two-year period beginning January 1, 2009 and ending December 31, 2010.

11. Retirement Plans and Postretirement Benefit Plans

The details of net periodic benefit cost of the pension plan, the restoration of retirement income plan and the postretirement benefit plans included in the Condensed Consolidated Financial Statements are as follows:

Net Periodic Benefit Cost

	Pension Plan			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2010 (A)	2009 (A)	2010 (B)	2009 (B)

Service cost	$ 4.1	$ 4.6	$ 12.5	$ 13.6
Interest cost	8.0	7.8	23.9	23.5
Expected return on plan assets	(10.6)	(8.2)	(31.8)	(24.7)
Amortization of net loss	5.3	5.8	15.9	17.6
Amortization of unrecognized prior service cost	0.6	0.2	1.8	0.6
Net periodic benefit cost	$ 7.4	$ 10.2	$ 22.3	$ 30.6

	Restoration of Retirement Income Plan			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2010 (A)	2009 (A)	2010 (B)	2009 (B)
Service cost	$ 0.3	$ 0.1	$ 0.7	$ 0.5
Interest cost	0.2	0.1	0.4	0.3
Amortization of net loss	---	0.1	0.2	0.2
Amortization of unrecognized prior service cost	0.1	0.2	0.5	0.5
Net periodic benefit cost	$ 0.6	$ 0.5	$ 1.8	$ 1.5

(A) In addition to the $8.0 million and $10.7 million of net periodic benefit cost recognized during the three months ended September 30, 2010 and 2009, respectively, the Company recognized the following:

Ÿ An increase in pension expense during the three months ended September 30, 2010 of $2.3 million and a reduction in pension expense of less than $0.1 million during the same period in 2009 to maintain the allowable amount to be recovered for pension expense in the Oklahoma jurisdiction which are identified as Deferred Pension Plan Expenses (see Note 1).

(B) In addition to the $24.1 million and $32.1 million of net periodic benefit cost recognized during the nine months ended September 30, 2010 and 2009, respectively, the Company recognized the following:

Ÿ An increase in pension expense during the nine months ended September 30, 2010 of $5.8 million and a reduction in pension expense of $2.2 million during the same period in 2009 to maintain the allowable amount to be recovered for pension expense in the Oklahoma jurisdiction which are identified as Deferred Pension Plan Expenses (see Note 1); and

Ÿ A reduction in pension expense during the nine months ended September 30, 2009 of $3.2 million in the Arkansas jurisdiction to reflect the approval of recovery of OG&E's 2006 and 2007 pension settlement costs in the May 2009 Arkansas rate order which are identified as Deferred Pension Plan Expenses (see Note 1).

	Postretirement Benefit Plans			
	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	2010	2009	2010	2009
Service cost	$ 1.1	$ 0.8	$ 3.2	$ 2.5
Interest cost	4.2	3.6	12.7	10.6
Expected return on plan assets	(1.7)	(1.6)	(5.2)	(4.9)
Amortization of transition obligation	0.7	0.7	2.1	2.1
Amortization of net loss	3.0	1.2	9.1	3.7
Amortization of unrecognized prior service cost	---	0.2	---	0.7
Net periodic benefit cost	$ 7.3	$ 4.9	$ 21.9	$ 14.7

Pension Plan Funding

In the third quarter of 2010, the Company contributed $10 million to its pension plan for a total contribution of $50 million to its pension plan during 2010. No additional contributions are expected in 2010.

12. Report of Business Segments

The Company's business is divided into four segments for financial reporting purposes. These segments are as follows: (i) electric utility, which is engaged in the generation, transmission, distribution and sale of electric energy, (ii) natural gas transportation and storage, (iii) natural gas gathering and processing and (iv) natural gas marketing. Other Operations primarily includes the operations of the holding company. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. In reviewing its segment operating results, the Company focuses on operating income as its measure of segment profit and loss, and, therefore, has presented this information below. The following tables summarize the results of the Company's business segments for the three and nine months ended September 30, 2010 and 2009.

Three Months Ended September 30, 2010 (In millions)	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
Operating revenues	$ 723.0	$ 103.5	$ 243.1	$ 206.5	$ ---	$ (150.7)	$ 1,125.4
Cost of goods sold	311.2	64.8	178.9	207.6	---	(149.9)	612.6
Gross margin on revenues	411.8	38.7	64.2	(1.1)	---	(0.8)	512.8
Other operation and maintenance	110.8	11.6	22.0	1.8	(3.2)	(0.6)	142.4
Depreciation and amortization	53.1	5.2	12.6	---	2.8	---	73.7
Taxes other than income	16.9	3.3	1.4	0.1	0.8	---	22.5
Operating income (loss)	$ 231.0	$ 18.6	$ 28.2	$ (3.0)	$ (0.4)	$ (0.2)	$ 274.2
Total assets	$ 5,882.7	$ 1,643.1	$ 941.1	$ 105.4	$ 2,834.4	$ (3,879.3)	$ 7,527.4

Three Months Ended September 30, 2009 (In millions)	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
Operating revenues	$ 577.9	$ 91.5	$ 156.1	$ 127.2	$ ---	$ (107.4)	$ 845.3
Cost of goods sold	235.7	47.4	107.3	130.5	---	(106.8)	414.1
Gross margin on revenues	342.2	44.1	48.8	(3.3)	---	(0.6)	431.2
Other operation and maintenance	85.7	9.8	19.6	2.5	(3.6)	(1.0)	113.0
Depreciation and amortization	47.3	5.2	11.9	---	2.8	---	67.2
Taxes other than income	16.0	3.1	1.4	---	0.8	---	21.3
Operating income (loss)	$ 193.2	$ 26.0	$ 15.9	$ (5.8)	$ ---	$ 0.4	$ 229.7
Total assets	$ 5,223.5	$ 1,336.6	$ 839.7	$ 115.8	$ 2,602.8	$ (3,220.6)	$ 6,897.8

Nine Months Ended September 30, 2010 (In millions)	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
Operating revenues	$ 1,679.8	$ 311.7	$ 726.4	$ 641.2	$ ---	$ (470.7)	$ 2,888.4
Cost of goods sold	792.8	191.9	527.5	644.8	---	(467.8)	1,689.2
Gross margin on revenues	887.0	119.8	198.9	(3.6)	---	(2.9)	1,199.2
Other operation and maintenance	305.9	35.2	66.8	6.6	(10.8)	(2.7)	401.0
Depreciation and amortization	153.4	16.0	37.5	---	8.3	---	215.2
Taxes other than income	51.8	10.6	4.9	0.3	2.9	---	70.5
Operating income (loss)	$ 375.9	$ 58.0	$ 89.7	$ (10.5)	$ (0.4)	$ (0.2)	$ 512.5

Total assets	$ 5,882.7	$ 1,643.1	$ 941.1	$ 105.4	$ 2,834.4	$ (3,879.3)	$ 7,527.4

Nine Months Ended September 30, 2009 (In millions)	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
Operating revenues	$ 1,339.9	$ 300.8	$ 436.9	$ 436.7	$ ---	$ (418.3)	$ 2,096.0
Cost of goods sold	595.0	174.3	302.1	434.9	---	(414.8)	1,091.5
Gross margin on revenues	744.9	126.5	134.8	1.8	---	(3.5)	1,004.5
Other operation and maintenance	248.9	29.4	62.6	7.8	(10.2)	(3.4)	335.1
Depreciation and amortization	139.1	16.0	32.9	---	7.8	---	195.8
Taxes other than income	48.4	9.9	4.2	0.3	2.7	---	65.5
Operating income (loss)	$ 308.5	$ 71.2	$ 35.1	$ (6.3)	$ (0.3)	$ (0.1)	$ 408.1
Total assets	$ 5,223.5	$ 1,336.6	$ 839.7	$ 115.8	$2,602.8	$ (3,220.6)	$ 6,897.8

13. Commitments and Contingencies

Except as set forth below and in Note 14, the circumstances set forth in Notes 13 and 14 to the Company's Consolidated Financial Statements included in the Company's 2009 Form 10-K appropriately represent, in all material respects, the current status of the Company's material commitments and contingent liabilities.

OG&E Railcar Lease Agreement

At September 30, 2010, OG&E had a noncancellable operating lease with purchase options, covering 1,462 coal hopper railcars to transport coal from Wyoming to OG&E's coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through OG&E's tariffs and fuel adjustment clauses. At the end of the lease term, which is January 31, 2011, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual fair value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of $31.5 million.

On February 10, 2009, OG&E executed a short-term lease agreement for 270 railcars in accordance with new coal transportation contracts with BNSF Railway and Union Pacific. These railcars were needed to replace railcars that have been taken out of service or destroyed. The lease agreement expired with respect to 135 railcars on November 2, 2009 and was not replaced. The lease agreement with respect to the remaining 135 railcars expired on March 5, 2010 and is now continuing on a month-to-month basis with a 30-day notice required by either party to terminate the agreement.

OG&E is also required to maintain all of the railcars it has under lease to transport coal from Wyoming and has entered into agreements with Progress Rail Services and WATCO, both of which are non-affiliated companies, to furnish this maintenance.

Oxley Litigation

OG&E has been sued by John C. Oxley D/B/A Oxley Petroleum et al. in the District Court of Haskell County, Oklahoma. This case has been pending for more than 11 years. The plaintiffs alleged that OG&E breached the terms of contracts covering several wells by failing to purchase gas from the plaintiffs in amounts set forth in the contracts. The plaintiffs' most recent Statement of Claim describes $2.7 million in take-or-pay damages (including interest) and $36 million in contract repudiation damages (including interest), subject to the limitation described below. In 2001, OG&E agreed to provide the plaintiffs with $5.8 million of consideration and the parties agreed to arbitrate the dispute. The arbitration hearing was completed and the final briefs were provided to the arbitration panel on March 17, 2010. On May 19, 2010, the panel issued an arbitration award in an amount less than the consideration previously paid by OG&E and, as a result, OG&E did not owe any additional amount. The Company now considers this case closed.

Natural Gas Measurement Cases