OGE ENERGY CORP
Form 10-Q
July 31, 2008

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 June 30, 2008

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	**73-1481638**
(State or other jurisdiction of incorporation or organization)	(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 x No o

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

Large accelerated filer x	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 x

At June 30, 2008, 92,297,196 shares of common stock, par value $0.01 per share, were outstanding.

OGE ENERGY CORP.

FORM 10-Q

FOR THE QUARTER ENDED JUNE 30, 2008

TABLE OF CONTENTS

i

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”, “intend”, “objective”, “plan”, “possible”, “potential”, “project” and similar expressions. Actual results may va materially. 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, 2007 (“2007 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, actions of rating agencies and their impact on capital expenditures;
- OGE Energy Corp.’s (“OGE Energy” and collectively, with its subsidiaries, the “Company”) ability and the ability of its subsidiaries to obtain financing on favorable terms;
- prices and availability of electricity, coal, natural gas and natural gas liquids (“NGL”), 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 (including the approval of regulatory filings related to its proposed acquisition of the Redbud power plant) 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 regulated accounting principles under Financial Accounting Standards Board (“FASB”) Statement of Financial Accounting Standards (“SFAS”) No. 71, “Accounting for the Effects of Certain Types of Regulation”;
- 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 impact of the proposed initial public offering of limited partner interests of OGE Enogex Partners L.P., a Delaware limited partnership (the “Partnership”); and
- other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission (“SEC”) including those listed in “Item 1A. Risk Factors” and in Exhibit 99.01 to the Company’s 2007 Form 10-K.

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 June 30, **2008**	2007	Six Months Ended June 30, **2008**	2007
OPERATING REVENUES				
Electric Utility operating revenues	**$ 520.7**	$ 429.9	**$ 907.1**	$ 770.6
Natural Gas Pipeline operating revenues	**615.0**	483.5	**1,223.3**	1,024.3
Total operating revenues	**1,135.7**	913.4	**2,130.4**	1,794.9
COST OF GOODS SOLD (exclusive of depreciation shown below)				
Electric Utility cost of goods sold	**294.7**	225.3	**523.5**	413.5
Natural Gas Pipeline cost of goods sold	**527.4**	399.6	**1,047.4**	878.3
Total cost of goods sold	**822.1**	624.9	**1,570.9**	1,291.8
Gross margin on revenues	**313.6**	288.5	**559.5**	503.1
Other operation and maintenance	**119.0**	105.9	**244.2**	204.7
Depreciation	**52.4**	47.8	**103.1**	96.5
Taxes other than income	**19.5**	17.6	**41.4**	38.5
OPERATING INCOME	**122.7**	117.2	**170.8**	163.4
OTHER INCOME (EXPENSE)				
Interest income	**1.2**	0.4	**2.1**	1.1
Allowance for equity funds used during construction	**---**	0.4	**---**	0.4
Other income	**4.5**	3.5	**8.4**	6.1
Other expense	**(14.2)**	(1.8)	**(18.3)**	(2.7)
Net other income (expense)	**(8.5)**	2.5	**(7.8)**	4.9
INTEREST EXPENSE				
Interest on long-term debt	**24.3**	22.2	**47.7**	44.3
Allowance for borrowed funds used during construction	**(0.9)**	(0.8)	**(1.6)**	(1.4)
Interest on short-term debt and other interest charges	**4.0**	3.6	**10.5**	6.3
Interest expense	**27.4**	25.0	**56.6**	49.2
INCOME BEFORE TAXES	**86.8**	94.7	**106.4**	119.1
INCOME TAX EXPENSE	**29.7**	32.1	**36.3**	39.3
NET INCOME	**$ 57.1**	$ 62.6	**$ 70.1**	$ 79.8
BASIC AVERAGE COMMON SHARES OUTSTANDING	**92.1**	91.8	**92.0**	91.6
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**92.5**	92.7	**92.5**	92.5
BASIC EARNINGS PER AVERAGE COMMON SHARE	**$ 0.62**	$ 0.68	**$ 0.76**	$ 0.87
DILUTED EARNINGS PER AVERAGE COMMON SHARE	**$ 0.62**	$ 0.68	**$ 0.76**	$ 0.86
DIVIDENDS DECLARED PER SHARE	**$ 0.3475**	$ 0.34	**$ 0.6950**	$ 0.68

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

OGE ENERGY CORP.

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	**June 30, 2008**	December 31, 2007
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 3.6**	$ 8.8
Accounts receivable, less reserve of $1.9 and $3.8, respectively	**404.0**	334.4
Accrued unbilled revenues	**61.9**	45.7
Fuel inventories	**110.1**	82.0
Materials and supplies, at average cost	**67.5**	63.6
Price risk management	**18.1**	7.7
Gas imbalances	**5.9**	6.7
Accumulated deferred tax assets	**31.0**	38.1
Fuel clause under recoveries	**87.4**	27.3
Prepayments	**5.7**	8.0
Other	**8.9**	7.2
Total current assets	**804.1**	629.5
OTHER PROPERTY AND INVESTMENTS, at cost	**47.9**	44.5
PROPERTY, PLANT AND EQUIPMENT		
In service	**7,031.6**	6,809.2
Construction work in progress	**200.9**	179.8
Total property, plant and equipment	**7,232.5**	6,989.0
Less accumulated depreciation	**2,793.8**	2,742.7
Net property, plant and equipment	**4,438.7**	4,246.3
DEFERRED CHARGES AND OTHER ASSETS		
Income taxes recoverable from customers, net	**16.9**	17.4
Regulatory asset - SFAS 158	**166.5**	174.6
Prepaid pension obligation	**32.9**	---
Price risk management	**17.5**	0.3
McClain Plant deferred expenses	**9.3**	12.4
Unamortized loss on reacquired debt	**18.3**	18.9
Unamortized debt issuance costs	**10.6**	8.3
Other	**74.5**	85.6
Total deferred charges and other assets	**346.5**	317.5
TOTAL ASSETS	**$ 5,637.2**	$ 5,237.8

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

OGE ENERGY CORP.

CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

(Unaudited)

(In millions)	**June 30, 2008**	December 31, 2007
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 438.7**	$ 295.8
Accounts payable	**373.7**	399.3
Dividends payable	**32.1**	31.9
Customer deposits	**57.5**	55.5
Accrued taxes	**33.9**	40.0
Accrued interest	**42.7**	37.0
Accrued compensation	**37.3**	53.9
Long-term debt due within one year	**---**	1.0
Price risk management	**14.3**	20.6
Gas imbalances	**11.7**	11.1
Fuel clause over recoveries	**---**	4.2
Other	**52.6**	38.2
Total current liabilities	**1,094.5**	988.5
LONG-TERM DEBT	**1,568.2**	1,344.6
COMMITMENTS AND CONTINGENCIES (NOTE 13)		
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued benefit obligations	**155.7**	156.2
Accumulated deferred income taxes	**891.6**	853.6
Accumulated deferred investment tax credits	**19.6**	22.0
Accrued removal obligations, net	**144.8**	139.7
Price risk management	**16.4**	11.3
Other	**43.3**	41.0
Total deferred credits and other liabilities	**1,271.4**	1,223.8
STOCKHOLDERS' EQUITY		
Common stockholders' equity	**768.8**	756.2
Retained earnings	**1,011.7**	1,005.7
Accumulated other comprehensive loss, net of tax	**(77.4)**	(81.0)
Total stockholders' equity	**1,703.1**	1,680.9
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 5,637.2**	$ 5,237.8

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)	Total
Balance at December 31, 2006	$ 0.9	$ 740.1	$ 890.8	$ (28.0)	$ 1,603.8
Comprehensive income					
Net income for first quarter of 2007	---	---	17.2	---	17.2
Other comprehensive income, net of tax					
Defined benefit pension plan and restoration of retirement income plan:					
Net loss, net of tax ($0.5 pre-tax)	---	---	---	0.3	0.3
Prior service cost, net of tax ($0.3 pre-tax)	---	---	---	0.2	0.2
Defined benefit postretirement plans:					
Net loss, net of tax ($0.1 pre-tax)	---	---	---	0.1	0.1
Net transition obligation, net of tax ($0.1 pre-tax)	---	---	---	0.1	0.1
Deferred hedging losses (($9.0) pre-tax)	---	---	---	(5.5)	(5.5)
Other comprehensive loss	---	---	---	(4.8)	(4.8)
Comprehensive income (loss)	---	---	17.2	(4.8)	12.4
Dividends declared on common stock	---	---	(31.2)	---	(31.2)
FIN No. 48 adoption (($6.2) pre-tax)	---	---	(3.8)	---	(3.8)
Issuance of common stock	---	9.5	---	---	9.5
Balance at March 31, 2007	$ 0.9	$ 749.6	$ 873.0	$ (32.8)	$ 1,590.7
Comprehensive income					
Net income for second quarter of 2007	---	---	62.6	---	62.6
Other comprehensive income, net of tax					
Defined benefit pension plan and restoration of retirement income plan:					
Net loss, net of tax ($0.6 pre-tax)	---	---	---	0.4	0.4
Prior service cost, net of tax ($0.3 pre-tax)	---	---	---	0.2	0.2
Defined benefit postretirement plans:					
Net loss, net of tax ($0.2 pre-tax)	---	---	---	0.1	0.1
Prior service cost, net of tax ($0.2 pre-tax)	---	---	---	0.1	0.1
Deferred hedging losses (($13.2) pre-tax)	---	---	---	(8.1)	(8.1)
Amortization of cash flow hedge ($0.2 pre-tax)	---	---	---	0.1	0.1
Other comprehensive loss	---	---	---	(7.2)	(7.2)
Comprehensive income (loss)	---	---	62.6	(7.2)	55.4
Dividends declared on common stock	---	---	(31.2)	---	(31.2)
Issuance of common stock	---	2.8	---	---	2.8
Balance at June 30, 2007	$ 0.9	$ 752.4	$ 904.4	$ (40.0)	$ 1,617.7

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

OGE ENERGY CORP.

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS'EQUITY (Continued)

(Unaudited)

(In millions)	Common Stock	Premium on Capital Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2007	**$ 0.9**	**$ 755.3**	**$ 1,005.7**	**$ (81.0)**	**$ 1,680.9**
Comprehensive income					
Net income for first quarter of 2008	**---**	**---**	**13.0**	**---**	**13.0**
Other comprehensive income, net of tax					
Defined benefit pension plan and restoration of retirement income plan:					
Net loss, net of tax ($0.5 pre-tax)	**---**	**---**	**---**	**0.3**	**0.3**
Prior service cost, net of tax ($0.1 pre-tax)	**---**	**---**	**---**	**0.1**	**0.1**
Defined benefit postretirement plans:					
Net loss, net of tax ($0.1 pre-tax)	**---**	**---**	**---**	**0.1**	**0.1**
Prior service cost, net of tax ($0.1 pre-tax)	**---**	**---**	**---**	**0.1**	**0.1**
Deferred hedging gains ($26.0 pre-tax)	**---**	**---**	**---**	**16.0**	**16.0**
Amortization of cash flow hedge ($0.1 pre-tax)	**---**	**---**	**---**	**0.1**	**0.1**
Other comprehensive income	**---**	**---**	**---**	**16.7**	**16.7**
Comprehensive income	**---**	**---**	**13.0**	**16.7**	**29.7**
Dividends declared on common stock	**---**	**---**	**(32.0)**	**---**	**(32.0)**
Issuance of common stock	**---**	**2.2**	**---**	**---**	**2.2**
Balance at March 31, 2008	**$ 0.9**	**$ 757.5**	**$ 986.7**	**$ (64.3)**	**$ 1,680.8**
Comprehensive income					
Net income for second quarter of 2008	**---**	**---**	**57.1**	**---**	**57.1**
Other comprehensive income, net of tax					
Defined benefit pension plan and restoration of retirement income plan:					
Net loss, net of tax ($0.6 pre-tax)	**---**	**---**	**---**	**0.4**	**0.4**
Prior service cost, net of tax ($0.1 pre-tax)	**---**	**---**	**---**	**0.1**	**0.1**
Defined benefit postretirement plans:					
Net loss, net of tax ($0.2 pre-tax)	**---**	**---**	**---**	**0.1**	**0.1**
Net transition obligation, net of tax ($0.1 pre-tax)	**---**	**---**	**---**	**0.1**	**0.1**
Deferred hedging losses (($22.1) pre-tax)	**---**	**---**	**---**	**(13.8)**	**(13.8)**
Other comprehensive loss	**---**	**---**	**---**	**(13.1)**	**(13.1)**
Comprehensive income (loss)	**---**	**---**	**57.1**	**(13.1)**	**44.0**
Dividends declared on common stock	**---**	**---**	**(32.1)**	**---**	**(32.1)**
Issuance of common stock	**---**	**10.4**	**---**	**---**	**10.4**
Balance at June 30, 2008	**$ 0.9**	**$ 767.9**	**$ 1,011.7**	**$ (77.4)**	**$ 1,703.1**

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

6

OGE ENERGY CORP.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Six Months Ended June 30,	
(In millions)	**2008**	2007
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	**$ 70.1**	$ 79.8
Adjustments to reconcile net income to net cash (used in) provided from operating activities		
Minority interest income (loss)	**3.3**	(0.2)
Depreciation	**103.1**	96.5
Deferred income taxes and investment tax credits, net	**41.2**	17.7
Allowance for equity funds used during construction	**---**	(0.4)
Loss (gain) on sale of assets	**0.1**	(0.1)
Loss on retirement of fixed assets	**0.1**	0.7
Write-down of regulatory assets	**9.2**	---
Stock-based compensation expense	**2.9**	1.9
Price risk management assets	**(27.6)**	20.3
Price risk management liabilities	**2.3**	(21.5)
Other assets	**(17.9)**	6.1
Other liabilities	**(17.2)**	(36.2)
Change in certain current assets and liabilities		
Accounts receivable, net	**(65.3)**	53.7
Accrued unbilled revenues	**(16.2)**	(13.9)
Fuel, materials and supplies inventories	**(31.9)**	(23.9)
Gas imbalance assets	**0.8**	(2.8)
Fuel clause under recoveries	**(60.1)**	---
Other current assets	**0.6**	4.3
Accounts payable	**(25.6)**	(17.6)
Customer deposits	**2.0**	3.7
Accrued taxes	**(3.7)**	3.2
Accrued interest	**5.7**	1.5
Accrued compensation	**(16.6)**	(10.6)
Gas imbalance liabilities	**0.6**	(4.9)
Fuel clause over recoveries	**(4.2)**	6.9
Other current liabilities	**10.0**	9.7
Net Cash (Used in) Provided from Operating Activities	**(34.3)**	173.9
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures (less allowance for equity funds used during construction)	**(279.4)**	(234.7)
Proceeds from sale of assets	**0.2**	1.0
Net Cash Used in Investing Activities	**(279.2)**	(233.7)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from long-term debt	**197.2**	---

Increase in short-term debt, net		**142.9**		68.3
Proceeds from line of credit		**50.0**		---
Issuance of common stock		**7.6**		7.2
Contributions from partners		**0.5**		5.7
Retirement of long-term debt		**(1.0)**		(3.0)
Repayment of line of credit		**(25.0)**		---
Dividends paid on common stock		**(63.9)**		(62.2)
Net Cash Provided from Financing Activities		**308.3**		16.0
NET DECREASE IN CASH AND CASH EQUIVALENTS		**(5.2)**		(43.8)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD		**8.8**		47.9
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$**	**3.6**	$	4.1

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

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 gas business in 1928 and is no longer engaged in the gas distribution business.

Enogex LLC and its subsidiaries (“Enogex”) is a provider of integrated natural gas midstream services. The vast majority of Enogex’s natural gas gathering, processing, transportation and storage assets are strategically located primarily in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex’s ongoing operations are organized into two business segments: (1) natural gas transportation and storage and (2) natural gas gathering and processing. Historically, Enogex had also engaged in natural gas marketing through its former subsidiary, OGE Energy Resources, Inc. (“OERI”). In connection with the proposed initial public offering of limited partner interests of the Partnership (discussed in Note 2), on January 1, 2008, Enogex distributed the stock of OERI to OGE Energy.

Effective April 1, 2008, Enogex Inc. converted from an Oklahoma corporation to a Delaware limited liability company. Also, effective April 1, 2008, Enogex Products Corporation, a wholly owned subsidiary of Enogex, converted from an Oklahoma corporation to an Oklahoma limited liability company.

In July 2008, OGE Energy and Electric Transmission America, a joint venture of subsidiaries of American Electric Power and MidAmerican Energy Holdings Co., formed a transmission joint venture to construct high-capacity transmission line projects in western Oklahoma. The Company will own 50 percent of the joint venture.

The Company allocates 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, based primarily upon head-count, occupancy, usage or 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 SEC. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States 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 June 30, 2008 and December 31, 2007, the results of its operations for the three and six months ended June 30, 2008 and 2007, and the results of its cash flows for the six months ended June 30, 2008 and 2007, 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 six months ended June 30, 2008 are not necessarily indicative of the results that may be expected for the year ending December 31, 2008 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 2007 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 the accounting principles prescribed by SFAS No. 71. SFAS No. 71 provides 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)	**June 30, 2008**		December 31, 2007	
Regulatory Assets				
Regulatory asset - SFAS 158	**$**	**166.5**	$	174.6
Fuel clause under recoveries		**87.4**		27.3
Deferred storm expenses		**33.7**		35.9
Deferred pension plan expenses		**19.8**		24.8
Unamortized loss on reacquired debt		**18.3**		18.9
Income taxes recoverable from customers, net		**16.9**		17.4
McClain Plant deferred expenses		**9.3**		12.4
Red Rock deferred expenses		**7.2**		14.7
Cogeneration credit rider under recovery		**---**		3.9
Miscellaneous		**1.3**		0.8
Total Regulatory Assets	**$**	**360.4**	$	330.7
Regulatory Liabilities				
Accrued removal obligations, net	**$**	**144.8**	$	139.7
Cogeneration credit rider over recovery		**3.0**		---
Centennial rider over recovery		**2.4**		2.9
Fuel clause over recoveries		**---**		4.2
Miscellaneous		**0.7**		1.4
Total Regulatory Liabilities	**$**	**150.9**	$	148.2

In June 2008, OG&E proposed a plan to the OCC designed to ease the financial burden on its customers of higher summer electric bills resulting from near-record high natural gas prices. OG&E proposed that it would recover only 50 percent of specified fuel costs during the hot summer months while delaying recovery of the remaining amount until the milder months of fall and early winter. OG&E's plan, which was implemented

July 1, 2008, helps reduce the near-term impact on its customers of higher fuel prices. Customers will generally be paying less for fuel costs during the summer than they otherwise might have absent this plan, while bills received in the months of October through December will generally include higher fuel costs in order to recover deferred fuel costs. The unrecovered amount is included in Fuel Clause Under Recoveries in the table above.

For a discussion of proceedings related to the deferred storm expenses and deferred Red Rock expenses and related reductions in the amounts previously recorded, 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 reduced or written off, as appropriate. If the Company were required to discontinue the application of SFAS No. 71 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.

Fuel Inventories

OG&E

Fuel inventories for the generation of electricity consist of coal, natural gas and oil. Historically, the Company has used the last-in, first-out ("LIFO") method of accounting for inventory removed from storage or stockpiles. Effective January 1, 2008, OG&E began using the weighted-average cost method to value inventory that is physically added to or withdrawn from storage or stockpiles in accordance with Oklahoma Senate Bill No. 609 ("SB 609") that was adopted in Oklahoma in 2007. SB 609 requires that electric utilities record fuel or natural gas removed from storage or stockpiles using the weighted-average cost method of accounting for inventory. In addition to satisfying the requirements of SB 609, management believes that the change from LIFO to weighted-average cost is also preferable because it provides for a more meaningful presentation in the financial statements taken as a whole and reduces the volatility associated with fuel price fluctuations on OG&E's customers. The majority of electric utility companies use the weighted-average cost method.

SFAS No. 154, "Accounting Changes and Error Corrections, a replacement of APB Opinion No. 20 and FASB Statement No. 3," requires that an entity report a change in accounting principle through retrospective application of the new principle to all prior periods unless it is impractical to do so. However, SFAS No. 71 requires that changes in accounting methods for regulated entities that affect allowable costs for rate-making purposes should be implemented in the same way that such an accounting change would be implemented for rate-making purposes. In accordance with an order from the OCC, OG&E's change in accounting method for inventory affected allowable costs for rate-making purposes, on a prospective basis only beginning January 1, 2008. Therefore the change in accounting was implemented prospectively for purposes of generally accepted accounting principles ("GAAP") and OG&E did not restate previously issued financial statements. Also, in accordance with the order from the OCC, on January 1, 2008, OG&E recorded an increase in Fuel Inventories of approximately $7.9 million with a corresponding offset recorded in Fuel Clause Under and Over Recoveries on the Company's Condensed Consolidated Financial Statements. OG&E began recovering costs from its customers using the weighted-average cost method for inventory on January 1, 2008.

The change in accounting for fuel inventory to the weighted-average cost method resulted in a higher fuel inventory balance of approximately $5.4 million at June 30, 2008. The change in accounting for fuel inventory to the weighted-average cost method did not impact the income statement for the three and six months ended June 30, 2008 as OG&E's fuel costs are passed through to its customers through automatic fuel adjustment clauses.

Price Risk Management Assets and Liabilities

In accordance with FASB Interpretation No. 39 (As Amended), "Offsetting of Amounts Related to Certain Contracts – an interpretation of APB Opinion No. 10 and FASB Statement No. 105," fair value amounts recognized for forward, interest rate swap, currency 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, currency 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 contracts under master netting agreements using a net fair value presentation. If these transactions with the same counterparty were presented on a gross basis in the Condensed Consolidated Balance Sheets, current Price Risk Management assets and liabilities would be approximately $54.6 million and $80.9 million, respectively, at June 30, 2008, and non-current Price Risk Management assets and liabilities would be approximately $58.1 million and $76.5 million, respectively, at June 30, 2008. If these transactions with the same counterparty were presented on a gross basis in the Condensed Consolidated Balance Sheets, current Price Risk Management assets and liabilities would be approximately $10.0 million and $51.4 million, respectively, at December 31, 2007, and non-current Price Risk Management assets and liabilities would be approximately $2.6 million and

$38.9 million, respectively, at December 31, 2007.

2. Formation of OGE Enogex Partners L.P.

In May 2007, the Company formed the Partnership as part of its strategy to further develop Enogex's natural gas midstream assets and operations. The Partnership has filed a registration statement with the SEC for a proposed initial public offering of its common units, representing limited partner interests in the Partnership (the "Offering"). At the date of this quarterly report, the registration statement relating to the Offering is not effective. In connection with the Offering, the Company is expected to contribute an approximate 25 percent membership interest in Enogex LLC to a wholly owned subsidiary of the Partnership that would serve as Enogex LLC's managing member and would control its assets and operations. A wholly owned subsidiary of the Company will retain the remaining approximately 75 percent membership interest in Enogex. It is currently contemplated that at the completion of the Offering, the Company will indirectly own an approximate 77 percent limited partner interest and a two percent general partner interest in the Partnership.

The completion of the Offering is subject to numerous conditions and no assurances can be made that it will be successfully completed. The Company expects to continue to evaluate strategic alternatives for Enogex, including other transactions that the Company believes could provide long-term value to its shareowners and the proposed Offering. The securities offered under the registration statement may not be sold, nor may offers to buy be accepted, prior to the time that the registration statement becomes effective. The information contained in this quarterly report with respect to the Offering shall not constitute an offer to sell or a solicitation of an offer to buy any securities.

From a financial reporting perspective, the formation of the Partnership had no effect on the Company's financial statements as of and for the periods ended June 30, 2008. In the event that, and beginning with the period in which, the Offering is completed, the Company will consolidate the results of the Partnership with minority interest treatment for the common units of the Partnership owned by unitholders other than the Company or its consolidated subsidiaries.

3. Accounting Pronouncements

In April 2008, the FASB issued FASB Staff Position ("FSP") FAS 142-3, "Determination of the Useful Life of Intangible Assets." This FSP applies to recognized intangible assets that are accounted for pursuant to SFAS No. 142, "Goodwill and Other Intangible Assets." This FSP amends the factors that should be considered in developing renewal and extension assumptions used to determine the useful life of a recognized intangible asset under SFAS No. 142. This FSP also seeks to improve the consistency between the useful life of a recognized intangible asset under SFAS No. 142 and the period of expected cash flows used to measure the fair value of the asset under SFAS No. 141(R), "Business Combinations," and GAAP. A company's own historical experience in renewing or extending similar arrangements should be considered in developing assumptions about renewal or extension used to determine the useful life of a recognized intangible asset. In the absence of such experience, assumptions that market participants would use about renewal or extension that are consistent with the highest and best use of the asset, adjusted for company specific factors, should be considered. The FSP requires that for recognized intangible assets, an entity should disclose information that enables the users of the financial statements to assess the extent to which the expected future cash flows associated with the asset are affected by the entity's intent and/or ability to renew or extend the arrangement. This FSP is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. The Company will adopt this FSP effective January 1, 2009. The adoption of this FSP is not expected to have an impact on the Company's consolidated financial position or results of operations as the Company does not currently have any intangible assets.

In May 2008, the FASB issued SFAS No. 162, "The Hierarchy of Generally Accepted Accounting Principles," which identifies the sources of accounting principles and the framework for selecting the principles to be used in the preparation of financial statements that are presented in conformity with GAAP. SFAS No. 162 transfers the GAAP hierarchy from the American Institute of Certified Public Accountant's ("AICPA") Statement on Auditing Standards ("SAS") No. 69, "The Meaning of *Present Fairly in Conformity with Generally Accepted Accounting Principles*" to the FASB because entities are responsible for selecting accounting principles for financial statements that are presented in conformity with GAAP. SFAS No. 162 states the hierarchy of accounting sources that should be used in applying GAAP. If the accounting treatment for a specific transaction or event is not specified in the accounting guidance, an entity shall first consider accounting principles for similar transactions or events and then other accounting literature. SFAS No. 162 is effective 60 days following the SEC's approval of the Public Company Accounting Oversight Board amendments to AU Section 411, "The Meaning *of Present Fairly in Conformity With Generally Accepted Accounting Principles*." The adoption of SFAS No. 162 will not have an impact on the Company's application of GAAP, consolidated financial position or results of operations.

4. Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, “Fair Value Measurements,” which defines fair value, establishes a framework for measuring fair value in GAAP and establishes a hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. SFAS No. 157 expands disclosures about the use of fair value to measure assets and liabilities in interim and annual periods subsequent to initial recognition. The guidance in SFAS No. 157 applies to derivatives and other financial instruments measured at fair value under SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities,” at initial recognition and in all subsequent periods. Therefore, SFAS No. 157 nullifies the guidance in footnote 3 of Emerging Issues Task Force ("EITF") Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." SFAS No. 157 also amends SFAS No. 133 to remove the guidance similar to that nullified in EITF 02-3. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The provisions of SFAS No. 157 generally are to be applied prospectively as of the beginning of the fiscal year in which it is initially applied. The Company adopted this new standard effective January 1, 2008.

The following table is a summary of the Company's assets and liabilities that are measured at fair value on a recurring basis in accordance with SFAS No. 157.

(In millions)		**June 30, 2008**	**Level 1**	**Level 2**	**Level 3**
Assets					
Gross derivative assets	**$**	**168.4**	39.7	113.3	15.4
Gas imbalance assets		**5.9**	---	5.9	---
Total	**$**	**174.3**	39.7	119.2	15.4
Liabilities					
Gross derivative liabilities	**$**	**223.5**	54.3	169.2	---
Gas imbalance liabilities		**11.7**	---	11.7	---
Asset retirement obligations		**5.1**	---	---	5.1
Total	**$**	**240.3**	54.3	180.9	5.1

The three levels defined by the SFAS No. 157 hierarchy and examples of each are as follows:

Level 1 inputs are quoted prices in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. An example of instruments that may be classified as Level 1 includes futures transactions for energy commodities traded on the New York Mercantile Exchange ("NYMEX").

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. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs include the following: (i) quoted prices for similar assets or liabilities in active markets; (ii) quoted prices for identical or similar assets or liabilities in markets that are not active; (iii) inputs other than quoted prices that are observable for the asset or liability; or (iv) inputs that are derived principally from or corroborated by observable market data by correlation or other means. 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 unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that observable inputs are not available. Unobservable inputs shall 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). Unobservable inputs shall be developed based on the best information available in the circumstances, which might include the reporting entity's own data. The reporting entity's own data used to develop unobservable inputs shall be adjusted if information is reasonably available that indicates that market participants would use different assumptions. 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 or the valuation of asset retirement obligations such that there are no closely related markets in which quoted prices are available.

The following table is a reconciliation of the Company’s total derivatives fair value to the Company’s Condensed Consolidated Balance Sheet at June 30, 2008.

(In millions)		June 30, 2008
Assets		
Gross derivative assets	$	168.4
Less: Amounts held in clearing broker accounts reflected in Other Current Assets		(55.8)
Less: Amounts offset under master netting agreements in accordance with FIN 39-1		(77.0)
Net Price Risk Management Assets	$	35.6
Liabilities		
Gross derivative liabilities	$	223.5
Less: Amounts held in clearing broker accounts reflected in Other Current Assets		(66.2)
Less: Amounts offset under master netting agreements in accordance with FIN 39-1, including amounts netted against collateral payments to counterparties		(126.6)
Net Price Risk Management Liabilities	$	30.7

The following table is a summary of the Company’s assets and liabilities that are measured at fair value on a recurring basis in accordance with SFAS No. 157 using significant unobservable inputs (Level 3).

(In millions)		Derivative Assets
Assets		
Balance at January 1, 2008	$	1.4
Total gains or losses (realized/unrealized)		
Included in earnings		---
Included in other comprehensive income		0.1
Purchases, sales, issuances and settlements, net		---
Transfers in and/or out of Level 3		---
Balance at March 31, 2008	$	1.5
Total gains or losses (realized/unrealized)		
Included in earnings		0.2
Included in other comprehensive income		(0.8)
Purchases, sales, issuances and settlements, net		14.5
Transfers in and/or out of Level 3		---
Balance at June 30, 2008	$	15.4
The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to assets held at June 30, 2008	$	0.2

(In millions)		**Asset Retirement Obligations**
Liabilities		
Balance at January 1, 2008	$	4.9
Total gains or losses (realized/unrealized)		
Included in earnings		0.1
Included in other comprehensive income		---
Purchases, sales, issuances and settlements, net		---
Transfers in and/or out of Level 3		---
Balance at March 31, 2008	$	5.0
Total gains or losses (realized/unrealized)		
Included in earnings		0.1
Included in other comprehensive income		---
Purchases, sales, issuances and settlements, net		---
Transfers in and/or out of Level 3		---
Balance at June 30, 2008	$	5.1
The amount of total gains or losses for the period included in earnings attributable to the change in unrealized gains or losses relating to liabilities held at June 30, 2008	$	---

Gains and losses (realized and unrealized) included in earnings for the three and six months ended June 30, 2008 attributable to the change in unrealized gains or losses relating to assets and liabilities held at June 30, 2008, if any, are reported in operating revenues.

The following information is provided regarding the estimated fair value of the Company's financial instruments, including derivative contracts related to the Company's price risk management activities, which have significantly changed since December 31, 2007.

	June 30, 2008		December 31, 2007	
(In millions)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Price Risk Management Assets				
Energy Trading Contracts	**$ 35.6**	**$ 35.6**	$ 8.0	$ 8.0

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 trading 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 management's estimate of current rates available for similar issues with similar maturities.

5. Stock-Based Compensation

On January 21, 1998, the Company adopted a Stock Incentive Plan (the "1998 Plan") and in 2003, the Company adopted another Stock Incentive Plan (the "2003 Plan" that replaced the 1998 Plan). In 2008, the Company adopted, and its shareowners approved, a new Stock Incentive Plan (the

"2008 Plan" and together with the 1998 Plan and the 2003 Plan, the "Plans"). The 2008 Plan replaced the 2003 Plan and no further awards will be granted under the 2003 Plan or the 1998 Plan. As under the 2003 Plan and the 1998 Plan, under the 2008 Plan, restricted stock, stock options, stock appreciation rights and performance units may be granted to officers, directors and other key employees of the Company and its subsidiaries. The Company has authorized the issuance of up to 2,750,000 shares under the 2008 Plan.

The Company recorded compensation expense of approximately $1.8 million pre-tax ($1.1 million after tax, or $0.01 per basic and diluted share) and approximately $2.9 million pre-tax ($1.8 million after tax, or $0.02 per basic and diluted share), respectively, during the three and six months ended June 30, 2008 related to the Company's share-based payments. The Company recorded compensation expense of approximately $0.6 million pre-tax ($0.4 million after tax, or less than $0.01 per basic and diluted share) and approximately $1.4 million pre-tax ($0.9 million after tax, or $0.01 per basic and diluted share), respectively, during the three and six months ended June 30, 2007 related to the Company's share-based payments.

The Company issues new shares to satisfy stock option exercises. During the three and six months ended June 30, 2008, there were 322,700 shares and 491,964 shares, respectively, of new common stock issued pursuant to the Company's Plans related to exercised stock options and payouts of earned performance units. The Company received approximately $7.4 million and $0.2 million during the three months ended June 30, 2008 and 2007, respectively, and approximately $7.6 million and $7.1 million during the six months ended June 30, 2008 and 2007, respectively, related to exercised stock options.

Registration Statement Filing

On June 19, 2008, the Company filed a Registration Statement on Form S-3 pursuant to which it may offer from time to time up to 6,000,000 shares of the Company's common stock.

6. Accumulated Other Comprehensive Income (Loss)

The components of accumulated other comprehensive loss at June 30, 2008 and December 31, 2007 are as follows:

(In millions)		**June 30, 2008**		December 31, 2007
Defined benefit pension plan and restoration of retirement income plan:				
Net loss, net of tax (($28.3) and ($29.4) pre-tax, respectively)	**$**	**(17.3)**	$	(18.0)
Prior service cost, net of tax (($1.0) and ($1.1) pre-tax, respectively)		**(0.6)**		(0.8)
Defined benefit postretirement plans:				
Net loss, net of tax (($8.2) and ($8.5) pre-tax, respectively)		**(3.5)**		(3.7)
Net transition obligation, net of tax (($0.9) and ($1.0) pre-tax, respectively)		**(0.6)**		(0.7)
Prior service cost, net of tax (($0.5) and ($0.7) pre-tax, respectively)		**(0.3)**		(0.4)
Deferred hedging losses, net of tax (($87.2) and ($90.9) pre-tax, respectively)		**(53.5)**		(55.7)
Settlement and amortization of cash flow hedge, net of tax (($2.5) and ($2.7) pre-tax, respectively)		**(1.6)**		(1.7)
Total accumulated other comprehensive loss, net of tax	**$**	**(77.4)**	$	(81.0)

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 or state and local income tax examinations by tax authorities for years before 2004. 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. In addition, OG&E earns both federal and Oklahoma state tax credits associated with the production from its Centennial wind farm that further reduce the Company's effective tax rate.

The Company follows the provisions of SFAS No. 109, “Accounting for Income Taxes,” which uses an asset and liability approach to accounting for income taxes. Under SFAS No. 109, deferred tax assets or liabilities are computed based on the difference between the financial statement and income tax bases of assets and liabilities using the enacted marginal tax rate. Deferred income tax expenses or benefits are based on the changes in the asset or liability from period to period.

8. Earnings Per Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	**2008**	2007	**2008**	2007
Average Common Shares Outstanding				
Basic average common shares outstanding	**92.1**	91.8	**92.0**	91.6
Effect of dilutive securities:				
Employee stock options and unvested stock grants	**0.1**	0.3	**0.2**	0.3
Contingently issuable shares (performance units)	**0.3**	0.6	**0.3**	0.6
Diluted average common shares outstanding	**92.5**	92.7	**92.5**	92.5
Anti-dilutive shares excluded from EPS calculation	**---**	---	**---**	---

9. Long-Term Debt

At June 30, 2008, the Company was in compliance with all of its debt agreements.

Optional Redemption of Long-Term Debt

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 (dollars in millions):

SERIES	DATE DUE	AMOUNT
1.40% - 3.18%	Garfield Industrial Authority, January 1, 2025	$ **47.0**
1.24% - 3.22%	Muskogee Industrial Authority, January 1, 2025	**32.4**
1.35% - 3.45%	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, the Company is obligated to repurchase such unremarketed Bonds. The Company believes that it has sufficient long-term liquidity to meet these obligations.

Registration Statement Filing

On June 5, 2008, OG&E filed a Registration Statement on Form S-3 pursuant to which it may offer from time to time up to $700 million of unsecured debt securities. OG&E expects to issue long-term debt later in 2008.

10. Short-Term Debt

The short-term debt balance was approximately $438.7 million and $295.8 million at June 30, 2008 and December 31, 2007, respectively. The following table shows the Company's revolving credit agreements and available cash at June 30, 2008.

Revolving Credit Agreements and Available Cash *(In millions)*

Entity	Amount Available	Amount Outstanding (A)	Weighted-Average Interest Rate	Maturity
OGE Energy Corp. (B)	$ 600.0	$ 173.4	2.99%	December 6, 2012 (E)
OG&E (C)	400.0	266.1	2.94% (F)	December 6, 2012 (E)
Enogex (D)	250.0	25.0	2.77%	March 31, 2013 (D)
	1,250.0	464.5	2.95%	
Cash	3.6	N/A	N/A	N/A
Total	$ 1,253.6	$ 464.5		

(A) Includes direct borrowings, outstanding commercial paper and letters of credit.
(B) This bank facility is available to back up the Company's commercial paper borrowings and to provide revolving credit borrowings. This bank facility c
(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
(D) On April 1, 2008, Enogex entered into a $250 million unsecured five-year revolving credit facility. Subject to certain limitations, the facility provides E
(E) In December 2006, the Company and OG&E amended and restated their revolving credit agreements to total in the aggregate $1.0 billion, $600 million
(F) Represents the weighted-average interest rate for the outstanding commercial paper borrowings of approximately $264.5 million.

The Company'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 back-up lines of credit could cause annual fees and borrowing rates to increase if an adverse ratings impact occurs. The impact of any future downgrades would result in an increase in the cost of short-term borrowings but would not result in any defaults or accelerations as a result of the rating changes. Any future downgrade of the Company would 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. Also, any downgrade below investment grade at OERI could require the Company to issue guarantees to support some of OERI's marketing operations.

Unlike the Company 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, 2007 and ending December 31, 2008.

11. Retirement Plans and Postretirement Benefit Plans

In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132R," which required an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity. The requirement to initially recognize the funded status of the defined benefit postretirement plan and the disclosure requirements were effective for the year ended December 31, 2007 for the Company.

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 June 30,		**Six Months Ended June 30,**	
(In millions)	**2008**	2007	**2008**	2007
Service cost	**$ 4.8**	$ 5.1	**$ 9.5**	$ 10.3
Interest cost	**7.8**	7.9	**15.6**	15.9
Return on plan assets	**(10.9)**	(10.9)	**(21.8)**	(21.9)
Amortization of net loss	**2.3**	2.6	**4.6**	5.2
Amortization of recognized prior service cost	**0.2**	1.4	**0.5**	2.6
Net periodic benefit cost (A)	**$ 4.2**	$ 6.1	**$ 8.4**	$ 12.1

(A) In addition to the $4.2 million and $6.1 million in SFAS No. 87, "Employers' Accounting for Pensions," net periodic benefit cost recognized during the three months ended June 30, 2008 and 2007, respectively, OG&E also recognized an expense of approximately $2.5 million and $1.3 million, respectively, related to the reversal of a portion of the regulatory asset identified as Deferred Pension Plan Expenses (see Note 1). In addition to the $8.4 million and $12.1 million in SFAS No. 87 net periodic benefit cost recognized during the six months ended June 30, 2008 and 2007, respectively, OG&E also recognized an expense of approximately $5.0 million and $2.4 million, respectively, related to the reversal of a portion of the regulatory asset identified as Deferred Pension Plan Expenses (see Note 1).

	Restoration of Retirement Income Plan			
	Three Months Ended June 30,		**Six Months Ended June 30,**	
(In millions)	**2008**	2007	**2008**	2007
Service cost	**$ 0.3**	$ 0.2	**$ 0.4**	$ 0.3
Interest cost	**0.1**	0.2	**0.2**	0.3
Amortization of net loss	**---**	---	**0.1**	0.1
Amortization of recognized prior service cost	**0.1**	0.1	**0.3**	0.3
Net periodic benefit cost	**$ 0.5**	$ 0.5	**$ 1.0**	$ 1.0

	Postretirement Benefit Plans			
	Three Months Ended June 30,		**Six Months Ended June 30,**	
(In millions)	**2008**	2007	**2008**	2007
Service cost	**$ 0.9**	$ 1.0	**$ 1.8**	$ 2.0
Interest cost	**3.4**	3.1	**6.7**	6.2
Return on plan assets	**(1.7)**	(1.5)	**(3.3)**	(3.0)
Amortization of transition obligation	**0.7**	0.7	**1.4**	1.4
Amortization of net loss	**1.0**	1.6	**2.0**	3.1
Amortization of recognized prior service cost	**0.5**	0.5	**1.0**	1.0
Net periodic benefit cost	**$ 4.8**	$ 5.4	**$ 9.6**	$ 10.7

Pension Plan Funding

The Company previously disclosed in its 2007 Form 10-K that it may contribute up to $50 million to its pension plan during 2008. In the second quarter of 2008, the Company contributed approximately $40 million to its pension plan and currently expects to contribute an additional $10 million to its pension plan during the remainder of 2008. Any further contributions to the pension plan during 2008 would be discretionary contributions, anticipated to be in the form of cash, and are not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended.

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. As discussed in Note 1, on

January 1, 2008, Enogex distributed the stock of OERI, which engages in the marketing of natural gas, to OGE Energy and, as a result, OERI is no longer a subsidiary of Enogex. Other Operations for the three and six months ended June 30, 2008 and 2007 primarily included 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 six months ended June 30, 2008 and 2007. The results of the Company’s business segments have been restated for all prior periods presented to conform to the 2008 presentation.

Three Months Ended June 30, 2008 *(In millions)*	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
Operating revenues	**$ 520.7**	**$ 186.3**	**$ 320.9**	**$ 446.0**	**$ ---**	**$ (338.2)**	**$ 1,135.7**
Cost of goods sold	**312.7**	**151.7**	**243.8**	**450.3**	**---**	**(336.4)**	**822.1**
Gross margin on revenues	**208.0**	**34.6**	**77.1**	**(4.3)**	**---**	**(1.8)**	**313.6**
Other operation and maintenance	**85.8**	**12.8**	**21.5**	**2.9**	**(2.4)**	**(1.6)**	**119.0**
Depreciation	**36.9**	**4.3**	**9.3**	**0.1**	**1.8**	**---**	**52.4**
Taxes other than income	**14.6**	**3.1**	**1.1**	**0.1**	**0.6**	**---**	**19.5**
Operating income (loss)	**$ 70.7**	**$ 14.4**	**$ 45.2**	**$ (7.4)**	**$ ---**	**$ (0.2)**	**$ 122.7**
Total assets	**$ 4,098.4**	**$ 1,168.2**	**$ 673.9**	**$ 273.4**	**$ 2,152.0**	**$ (2,728.7)**	**$ 5,637.2**

Three Months Ended June 30, 2007 *(In millions)*	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
Operating revenues	$ 429.9	$ 67.0	$ 193.0	$ 385.9	$ ---	$ (162.4)	$ 913.4
Cost of goods sold	237.3	26.8	152.4	370.0	---	(161.6)	624.9
Gross margin on revenues	192.6	40.2	40.6	15.9	---	(0.8)	288.5
Other operation and maintenance	78.1	11.9	16.9	2.4	(2.6)	(0.8)	105.9
Depreciation	34.6	4.3	6.9	0.1	1.9	---	47.8
Taxes other than income	13.3	2.7	0.8	0.1	0.7	---	17.6
Operating income	$ 66.6	$ 21.3	$ 16.0	$ 13.3	$ ---	$ ---	$ 117.2
Total assets	$ 3,696.7	$ 1,450.2	$ 862.4	$ 165.2	$ 2,038.6	$ (3,263.5)	$ 4,949.6

Six Months Ended June 30, 2008 *(In millions)*	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
Operating revenues	**$ 907.1**	**$ 343.2**	**$ 577.7**	**$ 922.9**	**$ ---**	**$ (620.5)**	**$ 2,130.4**
Cost of goods sold	**553.3**	**274.4**	**439.4**	**921.7**	**---**	**(617.9)**	**1,570.9**
Gross margin on revenues	**353.8**	**68.8**	**138.3**	**1.2**	**---**	**(2.6)**	**559.5**
Other operation and							

maintenance (A)		**180.1**		**24.7**		**42.4**		**5.7**		**(5.6)**		**(3.1)**		**244.2**
Depreciation		**73.2**		**8.4**		**17.6**		**0.1**		**3.8**		**---**		**103.1**
Taxes other than income		**30.5**		**6.6**		**2.2**		**0.3**		**1.8**		**---**		**41.4**
Operating income (loss)	**$**	**70.0**	**$**	**29.1**	**$**	**76.1**	**$**	**(4.9)**	**$**	**---**	**$**	**0.5**	**$**	**170.8**
Total assets	**$**	**4,098.4**	**$**	**1,168.2**	**$**	**673.9**	**$**	**273.4**	**$**	**2,152.0**	**$**	**(2,728.7)**	**$**	**5,637.2**

(A) In 2004, the Company adopted a standard costing model utilizing a fully loaded activity rate (including payroll, benefits, other employee related costs and overhead costs) to be applied to projects eligible for capitalization or deferral. In March 2008, the

19

Company determined that the application of the fully loaded activity rates had unintentionally resulted in the over-capitalization of immaterial amounts of certain payroll, benefits, other employee related costs and overhead costs in prior years. To correct this issue, in March 2008, the Company recorded a pre-tax charge of approximately $9.5 million ($5.8 million after tax, or $0.06 per basic and diluted share) as an increase in Other Operation and Maintenance Expense in the Condensed Consolidated Statements of Income for the three months ended March 31, 2008 and a corresponding $8.6 million decrease in Construction Work in Progress and $0.9 million decrease in Other Deferred Charges and Other Assets related to the regulatory asset associated with storm costs in the Condensed Consolidated Balance Sheets as of March 31, 2008.

Six Months Ended June 30, 2007 *(In millions)*	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
Operating revenues	$ 770.6	$ 126.1	$ 358.6	$ 848.1	$ ---	$ (308.5)	$ 1,794.9
Cost of goods sold	437.2	55.9	276.1	829.5	---	(306.9)	1,291.8
Gross margin on revenues	333.4	70.2	82.5	18.6	---	(1.6)	503.1
Other operation and maintenance	152.3	22.3	32.9	4.6	(5.8)	(1.6)	204.7
Depreciation	70.0	8.7	13.8	0.1	3.9	---	96.5
Taxes other than income	28.5	6.1	1.7	0.3	1.9	---	38.5
Operating income	$ 82.6	$ 33.1	$ 34.1	$ 13.6	$ ---	$ ---	$ 163.4
Total assets	$ 3,696.7	$ 1,450.2	$ 862.4	$ 165.2	$ 2,038.6	$ (3,263.5)	$ 4,949.6

13. Commitments and Contingencies

Except as set forth below and in Note 14, the circumstances set forth in Notes 16 and 17 to the Company's Consolidated Financial Statements included in the Company's 2007 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 December 31, 2007, OG&E had a noncancellable operating lease with purchase options, covering 1,409 coal hopper railcars to transport coal from Wyoming to OG&E's coal-fired generation units. In April 2008, OG&E amended its contract to add 55 new railcars for approximately $3.5 million. At the end of the new 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 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 approximately $31.5 million.

OG&E Coal Transportation Contracts

OG&E has transportation contracts for the transportation of coal to its coal-fired power plants. OG&E's current transportation contracts expire on December 31, 2008. OG&E is currently in the process of negotiating new contracts and expects its new contracts to contain higher transportation rates than in the current contracts.

Agreement with Cheyenne Plains Gas Pipeline Company, L.L.C.

Cheyenne Plains Gas Pipeline Company, L.L.C ("Cheyenne Plains") operates the Cheyenne Plains Pipeline that provides firm transportation services in Wyoming, Colorado and Kansas with a capacity of 730,000 decatherms/day ("Dth/day"). OERI entered into a Firm Transportation Service Agreement ("FTSA") with Cheyenne Plains in 2004, for 60,000 Dth/day of firm capacity on the Cheyenne Plains Pipeline. The FTSA was for a 10-year term beginning with the in-service date of the Cheyenne Plains Pipeline in March 2005 with an annual demand fee of approximately $7.4 million. Effective March 1, 2007, OERI and Cheyenne Plains amended the FTSA to provide for OERI to turn back 20,000 Dth/day of its capacity beginning January 2008 through the remainder of the term. OERI's new demand fee obligations, net of this turn back and other immaterial release agreements, are estimated to be approximately $5.1 million in 2008; $5.3 million for each of the years 2009 through 2012; $6.4 million for each of the years 2013 and 2014 and $1.7 million in 2015.

Agreement with Midcontinent Express Pipeline, LLC

In December 2006, Enogex entered into a firm capacity lease agreement with Midcontinent Express Pipeline, LLC ("MEP") for a primary term of 10 years (subject to possible extension) that would give MEP and its shippers access to capacity on Enogex's system. The quantity of capacity subject to the MEP lease agreement is currently 272 million cubic feet per day, with the quantity ultimately to be leased subject to being increased by mutual agreement pursuant to the lease agreement. In addition to MEP's lease of Enogex's capacity, the MEP project includes construction by MEP of a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. Pending necessary regulatory approval, the MEP project is currently expected to be in service during the first quarter of 2009. Enogex currently estimates that its capital expenditures related to this project will be approximately $94 million. The lease agreement with MEP is subject to certain contingencies, including regulatory approval. Prior to that approval, Enogex may incur expenditures of between approximately $20 million and $40 million primarily related to commitments for materials that can be sold or used in normal operations in the event the MEP project does not proceed. The amount not recovered or utilized for such expenditures is not expected to be material.

MEP filed an application with the FERC on October 9, 2007 requesting a certificate of public convenience and necessity authorizing MEP to construct its pipeline and lease certain capacity from Enogex. On October 9, 2007, Enogex also filed an application with the FERC for issuance of a limited jurisdiction certificate authorizing its lease agreement with MEP. Certain Enogex shippers filed motions to intervene in Enogex's FERC certificate proceeding, and some protested Enogex's certificate application. Protestors claimed that it is unduly discriminatory for Enogex to propose to lease capacity to MEP while not generally offering firm interstate transportation service, that the lease arrangement will adversely affect the availability of interruptible interstate transportation service on the Enogex system and that the lease payment specified under the MEP lease agreement is unduly preferential in MEP's favor. These protestors urged the FERC to reject the MEP lease arrangement or to condition its acceptance on a requirement that Enogex offer existing shippers taking interruptible interstate service the opportunity to convert that service to firm service. One protestor asked the FERC to consolidate the Enogex certificate proceeding with Enogex's Section 311 triennial rate proceeding currently pending before the FERC. On July 25, 2008, the FERC issued its order approving the MEP project including the approval of a limited jurisdiction certificate authorizing the Enogex lease agreement to MEP. Further, the FERC order rejected all claims raised by protestors regarding the lease agreement.

Environmental Laws and Regulations

Air

On March 15, 2005, the U.S. Environmental Protection Agency ("EPA") issued the Clean Air Mercury Rule ("CAMR") to limit mercury emissions from coal-fired boilers. On February 8, 2008, the U.S. Court of Appeals for the D.C. Circuit Court vacated the rule and on March 24, 2008, the EPA filed a petition for rehearing. On May 20, 2008, the U.S. Court of Appeals for the D.C. Circuit denied the petition. The parties have until August 19, 2008 to file a petition for review by the U.S. Supreme Court. The Company cannot predict the outcome of the federal litigation at this time. Until the rule was vacated, the CAMR required mercury monitoring to begin in 2009. Accordingly, OG&E installed mercury monitoring equipment on all five of its coal units. The cost of the monitoring equipment was approximately $5.0 million in 2007 and OG&E expects to spend approximately $0.7 million in 2008 to complete vendor qualification. Because the CAMR litigation is ongoing, the cost to install additional mercury controls is uncertain at this time but may be significant, particularly if the EPA develops more stringent requirements. Because of the uncertainty caused by the litigation regarding the CAMR, the promulgation of an Oklahoma rule that would apply to existing facilities has been delayed. Regulations to require mercury monitoring are being considered for proposal by the Oklahoma Department of Environmental Quality ("ODEQ"); however, is not expected that Oklahoma will propose new mercury regulations in 2008. OG&E will continue to participate in the state rule making process.

In September 2005, the ODEQ informally notified affected utilities that they would be required to perform a study to determine their impact on visibility in national parks and wilderness areas ("Class I areas"). Affected utilities are those which have "Best Available Retrofit Technology ("BART") eligible sources" (sources built between 1962 and 1977). For OG&E, these include various generating units at various generating stations. Regulations, however, allow an owner or operator of a BART-eligible source to request and obtain a waiver from BART if modeling shows no significant impact on visibility in nearby Class I areas. Based on this modeling, the ODEQ made a preliminary determination to accept an application for a waiver for the Horseshoe Lake generating station. The Horseshoe Lake waiver is expected to be included in the ODEQ state implementation plan. The due date for the ODEQ submission of the state implementation plan was December 17, 2007; however, the ODEQ has not yet submitted a plan to the EPA for approval. It is not known whether approval for the state implementation plan will be granted by the EPA.

The modeling did not support waivers for the affected units at the Seminole, Muskogee and Sooner generating stations. OG&E submitted a BART compliance plan for Seminole on March 30, 2007 committing to installation of nitrogen oxide (“NOX”) controls on all three units. At the same time, OG&E submitted a determination to the ODEQ that an alternative compliance plan for the affected units at the Muskogee and Sooner power plants will achieve overall greater visibility improvement than BART in the affected Class I areas and the alternative plan extends the timeline for compliance to 2018. The cost for this alternative compliance plan, including the BART compliance plan for the Seminole power plant (the alternative compliance plan and the BART compliance plan are collectively referred to herein as the “alternative plan”), was estimated at approximately $470 million in March 2007. The alternative plan included installing semi-dry scrubbers on three of four affected coal units and low NOX burner equipment on all four coal units. This alternative plan was subject to approval by the ODEQ and the EPA. The EPA provided an opinion to the ODEQ that OG&E’s alternative plan did not meet the requirements of the regional haze rules. On November 16, 2007, the ODEQ notified OG&E that additional analysis would be required before the OG&E alternative plan could be accepted. As required by the ODEQ, OG&E completed additional analysis and, on May 30, 2008, OG&E filed with the ODEQ the results of its BART evaluation for the affected generating units as well as withdrawing its alternative plan filed in March 2007. In the May 30, 2008 filing, OG&E indicated its intention to install low NOX combustion technology at its affected generating stations and to continue to burn low sulfur coal at its four coal-fired generating units at its Muskogee and Sooner generating stations. The capital expenditures associated with the installation of the low NOX combustion technology are expected to be approximately $110 million. OG&E believes that these control measures will achieve visibility improvements in a cost-effective manner. OG&E did not propose the installation of scrubbers at its four coal-fired generating units because OG&E concluded that, consistent with the EPA’s regulations on BART, the installation of scrubbers (at an estimated cost of $1.7 billion) would not be cost-effective. OG&E cannot predict what action the EPA or the ODEQ will take in response to OG&E’s May 30, 2008 filing. OG&E expects that a compliance plan will be approved by the EPA by December 31, 2008. Until the compliance plan is approved, the total cost of compliance, including capital expenditures, cannot be estimated by OG&E with a reasonable degree of certainty. OG&E expects that any necessary environmental expenditures will qualify as part of a pre-approval plan to handle state and federally mandated environmental upgrades which will be recoverable in Oklahoma from OG&E’s retail customers under House Bill 1910, which was enacted into law in May 2005.

Currently, the EPA has designated Oklahoma “in attainment” with the ambient standard for ozone of 0.08 parts per million (“PPM”). In March 2008, the EPA lowered the ambient primary and secondary standards to 0.075 PPM. Oklahoma has until March 2009 to designate any areas of non-attainment within the state, based on ozone levels in 2006 through 2008. Following the state’s designation, the EPA is expected to determine a final designation by March 2010. States will be required to meet the ambient standards between 2013 and 2030, with deadlines depending on the severity of their ozone level. Oklahoma City and Tulsa are the most likely areas to be designated non-attainment in Oklahoma. The Company cannot predict the final outcome of this evaluation or its timing or affect on OG&E’s or Enogex’s operations.

The ODEQ Clean Air Act Amendment Title V permitting program was approved by the EPA in March 1996. By March of 1997, OG&E had submitted all required permit applications. As of December 31, 2007, OG&E had received Title V permits for all of its generating stations and intends to continue to renew these permits as necessary. Air permit fees for OG&E’s generating stations were approximately $0.6 million in 2007 and for Enogex’s facilities were approximately $0.2 million in 2007. In January 2008, the ODEQ proposed fee increases of approximately 28 percent for Title V sources and 13 percent for minor sources. These fee increases were approved and became effective July 1, 2008.

In July 2008, OG&E received a request for information from the EPA regarding Clean Air Act compliance at OG&E’s Muskogee and Sooner generating plants. In recent years, the EPA has issued similar requests to numerous other electric utilities seeking to determine whether various maintenance, repair and replacement projects should have required permits under the Clean Air Act’s new source review process. OG&E believes it has acted in full compliance with the Clean Air Act and new source review process and is cooperating with the EPA. OG&E cannot predict what, if any, further actions the EPA may take with respect to this matter.

Water

OG&E received two Oklahoma Pollutant Discharge Elimination System (“OPDES”) renewal permits in February 2008 from the state of Oklahoma. OG&E is currently reviewing these permits to determine if they are reasonable in their requirements, allow operational flexibility and provide reductions in operating costs. In addition, OG&E expects to file an OPDES renewal application with the state of Oklahoma by August 4, 2008 for one of its generating stations.

Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of any cooling water intake structure reflect the “best available technology” for minimizing environmental impacts. The EPA Section 316(b) rules for existing facilities became effective July 23, 2004. On January 25, 2007, a federal court reversed and remanded certain portions of the Section 316(b) rules to the EPA. On July 9, 2007, the EPA suspended these portions of the Section 316(b) rules for existing

22

facilities. As a result of such suspension, permits required for existing facilities are to be developed by the individual states using their best professional judgment until the EPA completes its review of the suspended sections. In September 2007, the state of Oklahoma required a comprehensive demonstration study be submitted by January 7, 2008 for each affected facility. On January 7, 2008, OG&E submitted the requested studies for its facilities. Additionally, on April 14, 2008, the U.S. Supreme Court granted writs of *certiorari* and will review the question of whether the Section 316(b) rules authorize the EPA to compare costs with benefits in determining the best technology available for minimizing "adverse environmental impact" at cooling water intake structures. It is not clear what changes, if any, the EPA will ultimately make to the Section 316(b) rules or how those changes may affect OG&E. Depending on the ultimate analysis and final determinations regarding the Section 316(b) rules and the Oklahoma comprehensive demonstration studies, capital and/or operating costs may increase at any affected OG&E generating facility.

Other

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies. When appropriate, management consults with legal counsel and other appropriate experts to assess the claim. If in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Condensed Consolidated Financial Statements. Except as otherwise stated above, in Note 14 below, in Item 1 of Part II of this Form 10-Q, in Notes 16 and 17 of Notes to the Company's Consolidated Financial Statements included in the Company's 2007 Form 10-K and in Item 3 of that report, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

14. Rate Matters and Regulation

Except as set forth below, the circumstances set forth in Note 17 to the Company's Consolidated Financial Statements included in the Company's 2007 Form 10-K appropriately represent, in all material respects, the current status of any regulatory matters.

Completed Regulatory Matter

Enogex 2008 Fuel Filing

As required by the fuel tracker provisions of its Statement of Operating Conditions, Enogex files annually to update its fuel percentages for the East Zone and the West Zone. On November 15, 2007, Enogex made its annual filing to establish the fixed fuel percentages for its East Zone and West Zone for calendar year 2008 ("2008 Fuel Year"). There were no protests and the FERC accepted the proposed zonal fuel percentages for 2008 Fuel Year by order of December 19, 2007. Enogex expects to file its next annual fuel filing to establish fuel percentages for calendar year 2009 on or about November 15, 2008.

Pending Regulatory Matters

Proposed Acquisition of Redbud Power Plant

On January 21, 2008, OG&E entered into a Purchase and Sale Agreement (“Purchase and Sale Agreement”) with Redbud Energy I, LLC, Redbud Energy II, LLC and Redbud Energy III, LLC (“Redbud Sellers”), which are indirectly owned by Kelson Holdings LLC, a subsidiary of Harbinger Capital Partners Master Fund I, Ltd. and Harbinger Capital Partners Special Situations Fund, L.P. Pursuant to the Purchase and Sale Agreement, OG&E agreed to acquire from the Redbud Sellers the entire partnership interest in Redbud Energy LP which currently owns a 1,230 megawatt (“MW”) natural gas-fired, combined-cycle power generation facility in Luther, Oklahoma (“Redbud Facility”), for approximately $852 million, subject to working capital and inventory adjustments in accordance with the terms of the Purchase and Sale Agreement.

In connection with the Purchase and Sale Agreement, OG&E also entered into (i) an Asset Purchase Agreement (“Asset Purchase Agreement”) with the Oklahoma Municipal Power Authority (“OMPA”) and the Grand River Dam Authority (“GRDA”), pursuant to which OG&E agreed that it would, after the closing of the transaction contemplated by the Purchase and Sale Agreement, dissolve Redbud Energy LP and sell a 13 percent undivided interest in the Redbud Facility to the OMPA and sell a 36 percent undivided interest in the Redbud Facility to the GRDA, and (ii) an Ownership and Operating Agreement (“Ownership and Operating Agreement”) with the OMPA and the GRDA, pursuant to which OG&E, the OMPA and the GRDA, following the completion of the transaction contemplated by the Asset Purchase Agreement, would jointly own the Redbud

Facility and OG&E will act as the operations manager and perform the day-to-day operation and maintenance of the Redbud Facility. Under the Ownership and Operating Agreement, each of the parties would be entitled to its pro rata share, which is equal to its respective ownership interest, of all output of the Redbud Facility and would pay its pro rata share of all costs of operating and maintaining the Redbud Facility, including its pro rata share of the operations manager's general and administrative overhead allocated to the Redbud Facility.

The transactions described above are subject to an order from the FERC authorizing the contemplated transactions and an order from the OCC approving the prudence of the transactions and an appropriate reasonable recovery mechanism, and other customary conditions. OG&E will not be obligated to complete the transactions if the orders from the FERC and the OCC contain any conditions or restrictions which are materially more burdensome than those proposed in OG&E's applications. Either OG&E or the Redbud Sellers may terminate the Purchase and Sale Agreement if the closing has not occurred on or prior to November 16, 2008; provided that the Redbud Sellers have the option to extend such deadline for up to an additional 180 days if the sole reason the closing has not occurred is because the governmental and regulatory approvals have not been obtained. On March 20, 2008, OG&E and Redbud Energy LP filed an application with the FERC under Section 203 of the Federal Power Act to effectuate the transactions described above. On April 14, 2008, the OMPA filed a motion to intervene in support of the application. On April 10, 2008 and April 18, 2008, respectively, AES Shady Point, LLC ("AES") filed a motion to intervene and protest in the proceeding. On May 6, 2008, OG&E and Redbud Energy LP filed a joint answer to AES's protest.

OG&E filed an application with the OCC in March 2008 asking the OCC to approve the prudency of the transactions and an appropriate reasonable recovery mechanism. On July 30, 2008, a settlement agreement was signed in OG&E's Redbud pre-approval application. The settlement determined that the acquisition of a 51 percent interest in Redbud at the agreed upon $434.5 million purchase price plus transaction costs is prudent and that the facility is used and useful. A rider will be implemented upon closing of the purchase and integration of Redbud into OG&E's generation portfolio. The rider will recover the Oklahoma jurisdiction revenue requirement until new rates are implemented that include Redbud's net investment, operation and maintenance expense, depreciation expense and ad valorem taxes. The OCC rules provide that the OCC has up to 240 days to issue an order determining OG&E's pre-approval request. There can be no assurances that the transactions will be completed or as to their ultimate timing.

Cancelled Red Rock Power Plant

On October 11, 2007, the OCC issued an order denying OG&E and Public Service Company of Oklahoma's ("PSO") request for pre-approval of their proposed 950 MW Red Rock power plant project. The plant, which was to be built at OG&E's Sooner plant site, was to be 42 percent owned by OG&E, 50 percent owned by PSO and eight percent owned by the OMPA. As a result, on October 11, 2007, OG&E, PSO and the OMPA agreed to terminate agreements to build and operate the plant. At December 31, 2007, OG&E had incurred approximately $17.5 million of capitalized costs associated with the Red Rock power plant project. In December 2007, OG&E filed an application with the OCC requesting authorization to defer, and establish a method of recovery of, approximately $14.7 million of Oklahoma jurisdictional costs associated with the Red Rock power plant project. Specifically, OG&E requested authorization to sell approximately $14.7 million of its sulfur dioxide ("SO_2") allowances and to retain 100 percent of the proceeds to offset the $14.7 million of Red Rock costs. Under a prior order of the OCC, 90 percent of the proceeds from sales of SO_2 allowances were to be credited to ratepayers. Any portion of the $14.7 million of deferred costs that the OCC does not approve for recovery by OG&E will be expensed. In April 2008, the OCC Staff and other parties in this matter filed responses to OG&E's application. Two parties proposed no recovery of the deferred costs. The OCC Staff proposed recovery of approximately $10.8 million (approximately 73.5 percent) through a regulatory asset accruing a return until OG&E's next general retail rate case. Also, in its response to OG&E's Red Rock cost recovery application, the OCC Staff recommended that OG&E sell SO_2 allowances and retain 100 percent of the proceeds from the sale which should be used to offset OG&E's December 2007 ice storm costs. These ice storm costs were included as part of the regulatory asset balance of approximately $35.9 million at December 31, 2007 (see Note 1), in accordance with a prior order of the OCC, pending recovery in a future rate case. A settlement conference was held on May 2, 2008. On June 27, 2008, OG&E filed an application requesting a Storm Cost Recovery Rider ("SCRR") for the years 2007 through 2009 to recover excess storm damage costs and, at the same time, filed a motion to consolidate for hearing the Red Rock application and the SCRR application. On July 24, 2008, a settlement agreement was signed by all the parties involved in the two cases. Under the terms of the settlement agreement, OG&E will: (i) recover approximately $7.2 million, or 50 percent, of the Oklahoma jurisdictional portion of the Red Rock power plant deferred costs through a regulatory asset, (ii) amortize the Red Rock regulatory asset over a 27-year amortization period and earn the OCC's authorized rate of return beginning with OG&E's next rate case, (iii) accrue carrying costs on the debt portion of the Red Rock regulatory asset from October 1, 2007 until the date OG&E begins to recover the regulatory asset through the base rates established in OG&E's next rate case, (iv) recover the OCC Staff and Attorney General consulting fees of approximately $0.3 million related to the Red Rock pre-approval case, in OG&E's next rate case by amortizing this over a two-year period, (v) recover approximately $33.7 million of the 2007 storm costs regulatory asset, which resulted in a write-down of approximately $1.5 million, (vi) implement the SCRR to recover OG&E's actual storm expense for the four-year period from 2006 through

24

2009, (vii) retain the first $3.4 million from the sale of excess SO2 allowances, (viii) reduce storm costs recovered through the SCRR by the proceeds from the sale of SO2 allowances above the amount retained by OG&E and (ix) earn the most recent OCC authorized return on the unrecovered storm cost balance through the SCRR. A hearing on the consolidated cases is scheduled for August 4, 2008. On June 30, 2008, OG&E wrote down the Red Rock deferred cost to its net present value, which resulted in a pre-tax charge of approximately $7.5 million, which is currently included in Deferred Charges and Other Assets with an offset in Other Expense on the Company's Condensed Consolidated Financial Statements. The write-downs of deferred costs for both the Red Rock power plant and storm costs resulted in a pre-tax charge of approximately $9.0 million for the quarter ended June 30, 2008.

OG&E FERC Formula Rate Filing

On November 30, 2007, OG&E made a filing at the FERC to increase its transmission rates to wholesale customers moving electricity on OG&E's transmission lines. Interventions and protests were due by December 21, 2007. While several parties filed motions to intervene in the docket, only the OMPA filed a protest to the contents of OG&E's filing. OG&E filed an answer to the OMPA's protest on January 7, 2008. On January 31, 2008, the FERC issued an order (i) conditionally accepting the rates; (ii) suspending the effectiveness of such rates for five months, to be effective July 1, 2008, subject to refund; (iii) establishing hearing and settlement judge procedures; and (iv) directing OG&E to make a compliance filing. Settlement conferences were held on February 20, May 9 and July 8, 2008. Another settlement conference is scheduled for August 20, 2008. In July 2008, rates were implemented in an annual amount of approximately $2.4 million, subject to refund.

OG&E Arkansas Rate Case Filing

Beginning in early 2008, OG&E began developing a rate case filing for the Arkansas jurisdiction. In June 2008, OG&E filed a notice with the APSC that it expected to file its rate case in August 2008, requesting an increase in electric rates with a targeted implementation date of July 2009. The amount of the requested increase has not yet been determined.

Renewable Energy Proposal

OG&E announced in October 2007 its goal to increase its wind power generation over the next four years from its current 170 MWs to 770 MWs and, as part of this plan, OG&E expects to issue a request for proposal for wind power generation in the third quarter of 2008.

OG&E filed an application on May 19, 2008 with the OCC requesting pre-approval to recover from Oklahoma customers the cost to construct a transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma at a cost of approximately $211 million. This transmission line is a critical first step to increased wind development in western Oklahoma. In the application, OG&E also requested authorization to implement a recovery rider to be effective when the transmission line is completed and in service, which is expected during 2010. Finally, the application requested the OCC to approve new renewable tariff offerings to OG&E's Oklahoma customers. On July 11, 2008, the OCC Staff filed responsive testimony recommending approval of OG&E's renewable plan and the Oklahoma Industrial Energy Consumers opposed OG&E's request. A settlement conference is scheduled for July 31, 2008 with a hearing scheduled to begin on August 7, 2008. Separately, on July 29, 2008, the Southwest Power Pool ("SPP") Board of Directors approved the proposed transmission line discussed above.

Enogex FERC Section 311 2007 Rate Case

On October 1, 2007, Enogex made its required triennial rate filing at the FERC to update its Section 311 maximum interruptible transportation rates for service in the East Zone and West Zone. Enogex's filing requested an increase in the maximum zonal rates and proposed to place such rates into effect on January 1, 2008. A number of parties intervened and some also filed protests.

The regulations provide that the FERC has 150 days to act on the filing but also permit the FERC to issue an order extending the time period for action. By order of February 28, 2008, the FERC extended the time period in this docket by 120 days and encouraged the parties to settle. No action has yet been taken by the FERC and the parties are currently in settlement negotiations.

On November 13, 2007, one of the protesting intervenors filed to consolidate the Enogex rate case with a separate Enogex application pending before the FERC allowing Enogex to lease firm capacity to MEP and with separate applications filed by MEP with the FERC for a certificate to construct and operate the new MEP pipeline and to lease firm capacity from Enogex. Additional pleadings have been filed by this intervenor and Enogex and MEP have separately opposed this intervenor's assertions. By order dated July 25, 2008, the FERC approved the MEP project and denied the intervenors' request for consolidation of the MEP proceedings with the Enogex rate case. Enogex has not, as of yet, placed the increased rates into effect. Enogex must file its next rate case no later than October 1, 2010 to comply with the FERC's requirement for triennial filings.

Market-Based Rate Authority

On December 22, 2003, OG&E and OERI filed a triennial market power update based on the supply margin assessment test. On May 13, 2004, the FERC directed all utilities with pending three year market-based reviews to revise the generation market power portion of their three year review to address the new interim tests. OG&E and OERI submitted a compliance filing to the FERC on February 7, 2005 that applied the interim tests to OG&E and OERI. In the compliance filing, OG&E and OERI passed the pivotal supplier screen but did not pass the market share screen in OG&E's control area. OG&E and OERI provided an explanation as to why their failure of the market share screen in OG&E's control area should not be viewed as an indication that they can exercise generation market power.

On June 7, 2005, the FERC issued an order on OG&E's and OERI's market-based rate filing. Because OG&E and OERI failed the market share screen for OG&E's control area, the FERC established hearing procedures to investigate whether OG&E and OERI may continue to sell power at market-based rates in OG&E's control area. The order established a rebuttable presumption that OG&E and OERI have the ability to exercise market power in OG&E's control area. OG&E and OERI were requested to provide additional information that demonstrates to the FERC that they cannot exercise market power in the first-tier markets as well. However, the order conditionally allows OG&E and OERI to sell power in first-tier markets subject to OG&E and OERI providing additional information that clearly shows that they pass the market share screen for the first-tier markets. OG&E and OERI provided that additional information on July 7, 2005. On August 8, 2005, OG&E and OERI informed the FERC that they will: (i) adopt the FERC default rate mechanism for sales of one week or less to loads that sink in OG&E's control area; and (ii) commit not to enter into any sales with a duration of between one week and one year to loads that sink in OG&E's control area. OG&E and OERI also informed the FERC that any new agreements for long-term sales (one year or longer in duration) to loads that sink in OG&E's control area will be filed with the FERC and that OG&E and OERI will not make such sales under their respective market-based rate tariffs. On January 20, 2006, the FERC issued a Notice of Institution of Proceeding and Refund Effective Date for the purpose of establishing the date from which any subsequent market-based sales would be subject to refund in the event the FERC concludes after investigation that the rates for such sales are not just and reasonable. The refund effective date was March 27, 2006.

On March 21, 2006, the FERC issued an order conditionally accepting OG&E's and OERI's proposal to mitigate the presumption of market power in OG&E's control area. First, the FERC accepted the additional information related to first-tier markets submitted by OG&E and OERI, and concluded that OG&E and OERI satisfy the FERC's generation market power standard for directly interconnected first-tier control areas. Second, the FERC directed the Company to make certain revisions to its mitigation proposal and file a cost-based rate tariff for short-term sales (one week or less) made within OG&E's control area. The FERC also expanded the scope of the proposed mitigation to all sales made within OG&E's control area (instead of only to sales sinking to load within OG&E's control area). On April 20, 2006, OG&E submitted: (i) a compliance filing containing the specified revisions to OG&E's market-based rate tariffs and the new cost-based rate tariff; and (ii) a request for rehearing asking the FERC to reconsider its expanded mitigation directive contained in the March 21, 2006 order. On May 22, 2006, the FERC issued a tolling order that effectively provided the FERC additional time to consider the April 20, 2006 rehearing request. On July 25, 2006 and August 25, 2006, pursuant to a FERC March 20, 2006 order, OG&E and OERI filed revisions to their market-based rate tariffs to allow them to sell energy imbalance service into the wholesale markets administered by the SPP at market-based rates. On April 4, 2008, the FERC rejected OG&E's April 20, 2006 request for rehearing and approved in part and rejected in part OG&E's April 20, 2006 compliance filing. The April 4, 2008 order directed OG&E to evaluate whether any refunds are required to comply with the April 4, 2008 order and to: (i) make any necessary refunds, or (ii) file a report with the FERC stating that no refunds are due. Refunds would apply only to new market-based sales made or new market-based contracts entered into after the March 21, 2006 order. The April 4, 2008 order also directed OG&E to make another compliance filing to revise its market-based rate tariffs to adhere to the FERC's June 21, 2007 final rule that revised standards for market-based rate sales of electric energy, capacity and ancillary services. On May 5, 2008, OG&E submitted a compliance report stating that no refunds were due. On May 30, 2008, OG&E and OERI submitted to the FERC a change in status report notifying the FERC that OG&E had entered into a contract with Westar Energy under which OG&E agreed to purchase 300 MWs of capacity and energy for the periods from May 1, 2008 through August 31, 2008, and from May 1, 2009 through August 31, 2009. OG&E and OERI explained that this purchase agreement was not material to the FERC's grant of market-based rate status to OG&E and OERI. The FERC has not yet acted on OG&E's and OERI's change of status filing.

State Legislative Initiatives

House Bill 2813 ("HB 2813") was signed into law in May 2008, at which time it became effective. HB 2813 was created in order to advance the development of Oklahoma's vast wind power potential. This law provides for additional financial certainty for transmission line projects deemed necessary for the development of wind energy. The costs associated with such transmission lines are to be presumed to be recoverable if the lines are in service within five years of the passage of the law and meet the necessary criteria. OG&E has announced its intentions to build transmission lines and substantially increase the amount of generation it produces by wind, and management believes that this legislation increases the likelihood of recovering the costs associated with the construction of transmission lines.

House Bill 1739 ("HB 1739") was signed into law in May 2008, with an effective date of January 1, 2009. HB 1739 creates a system whereby utilities can divide their territories with the proper government oversight. The bill only relates to new customers in the territory and does not allow switching of existing customers. The law also codifies the right of investor-owned utilities to be able to continue serving in annexed territories of cities with municipal electric systems, where they can demonstrate a prior right to be in the annexed territory. The law is retroactive to include previous annexations as well as those that may occur in the future. This law also clarifies which utilities can serve in a territory annexed by a city because duplication of infrastructure has caused problems over the years since it possesses a potential safety hazard to line workers. The benefits of this law to OG&E include being able to reduce future duplication of power lines and other infrastructure as well as clearly establishing the right to serve in areas previously considered legally questionable by certain parties.

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

Introduction

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.

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 gas business in 1928 and is no longer engaged in the gas distribution business.

Enogex LLC and its subsidiaries ("Enogex") is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting and storing natural gas. The vast majority of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located primarily in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex's ongoing operations are organized into two business segments: (1) natural gas transportation and storage and (2) natural gas gathering and processing. Historically, Enogex had also engaged in natural gas marketing through its former subsidiary, OGE Energy Resources, Inc. ("OERI"). In connection with the proposed initial public offering of common units of OGE Enogex Partners L.P., a Delaware limited partnership (the "Partnership"), discussed in Note 2 of Notes to Condensed Consolidated Financial Statements, on January 1, 2008, Enogex distributed the stock of OERI to OGE Energy.

Effective April 1, 2008, Enogex Inc. converted from an Oklahoma corporation to a Delaware limited liability company. Also, effective April 1, 2008, Enogex Products Corporation, a wholly owned subsidiary of Enogex, converted from an Oklahoma corporation to an Oklahoma limited liability company.

In May 2007, the Company formed the Partnership as part of its strategy to further develop Enogex's natural gas midstream assets and operations. The Partnership has filed a registration statement with the Securities and Exchange Commission for a proposed initial public offering of its common units, representing limited partner interests in the Partnership (the "Offering"). At the date of this quarterly report, the registration statement relating to the Offering is not effective. In connection with the Offering, the Company is expected to contribute an approximate 25 percent membership interest in Enogex LLC to a wholly owned subsidiary of the Partnership that would serve as Enogex LLC's managing member and would control its assets and operations. A wholly owned subsidiary of the Company will retain the remaining approximately 75 percent membership interest in Enogex LLC. It is currently contemplated that at the completion of the Offering, the Company will indirectly own an approximate 77 percent limited partner interest and a two percent general partner interest in the Partnership.

The completion of the Offering is subject to numerous conditions and no assurances can be made that it will be successfully completed. The Company expects to continue to evaluate strategic alternatives for Enogex, including other transactions that the Company believes co