OGE ENERGY CORP
Form 10-Q
May 07, 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 March 31, 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 March 31, 2008, 91,974,496 shares of common stock, par value $0.01 per share, were outstanding.

OGE ENERGY CORP.

FORM 10-Q

FOR THE QUARTER ENDED MARCH 31, 2008

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Part II – OTHER INFORMATION

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 the 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)

	Three Months Ended March 31,	
(In millions, except per share data)	**2008**	2007
OPERATING REVENUES		
Electric Utility operating revenues	**$ 386.4**	$ 340.7
Natural Gas Pipeline operating revenues	**608.3**	540.8
Total operating revenues	**994.7**	881.5
COST OF GOODS SOLD (exclusive of depreciation shown below)		
Electric Utility cost of goods sold	**228.8**	188.2
Natural Gas Pipeline cost of goods sold	**520.0**	478.7
Total cost of goods sold	**748.8**	666.9
Gross margin on revenues	**245.9**	214.6
Other operation and maintenance	**125.2**	98.8
Depreciation	**50.7**	48.7
Taxes other than income	**21.9**	20.9
OPERATING INCOME	**48.1**	46.2
OTHER INCOME (EXPENSE)		
Interest income	**0.9**	0.7
Other income	**3.9**	2.6
Other expense	**(4.1)**	(0.9)
Net other income	**0.7**	2.4
INTEREST EXPENSE		
Interest on long-term debt	**23.4**	22.1
Allowance for borrowed funds used during construction	**(0.7)**	(0.6)
Interest on short-term debt and other interest charges	**6.5**	2.7
Interest expense	**29.2**	24.2
INCOME BEFORE TAXES	**19.6**	24.4
INCOME TAX EXPENSE	**6.6**	7.2
NET INCOME	**$ 13.0**	$ 17.2
BASIC AVERAGE COMMON SHARES OUTSTANDING	**91.9**	91.5
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**92.5**	92.4
BASIC EARNINGS PER AVERAGE COMMON SHARE	**$ 0.14**	$ 0.19
DILUTED EARNINGS PER AVERAGE COMMON SHARE	**$ 0.14**	$ 0.19
DIVIDENDS DECLARED PER SHARE	**$ 0.3475**	$ 0.34

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

OGE ENERGY CORP.

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	**March 31, 2008**	December 31, 2007
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 2.7**	$ 8.8
Accounts receivable, less reserve of $2.3 and $3.8, respectively	**343.1**	334.4
Accrued unbilled revenues	**37.2**	45.7
Fuel inventories	**72.8**	82.0
Materials and supplies, at average cost	**68.3**	63.6
Price risk management	**8.2**	7.7
Gas imbalances	**5.7**	6.7
Accumulated deferred tax assets	**27.3**	38.1
Fuel clause under recoveries	**30.1**	27.3
Prepayments	**8.3**	8.0
Other	**5.7**	7.2
Total current assets	**609.4**	629.5
OTHER PROPERTY AND INVESTMENTS, at cost	**44.0**	44.5
PROPERTY, PLANT AND EQUIPMENT		
In service	**6,914.0**	6,809.2
Construction work in progress	**183.4**	179.8
Total property, plant and equipment	**7,097.4**	6,989.0
Less accumulated depreciation	**2,767.8**	2,742.7
Net property, plant and equipment	**4,329.6**	4,246.3
DEFERRED CHARGES AND OTHER ASSETS		
Income taxes recoverable from customers, net	**17.1**	17.4
Regulatory asset - SFAS 158	**170.5**	174.6
Price risk management	**2.6**	0.3
McClain Plant deferred expenses	**10.9**	12.4
Unamortized loss on reacquired debt	**18.6**	18.9
Unamortized debt issuance costs	**10.9**	8.3
Other	**83.7**	85.6
Total deferred charges and other assets	**314.3**	317.5
TOTAL ASSETS	**$ 5,297.3**	$ 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)	**March 31, 2008**	December 31, 2007
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 266.3**	$ 295.8
Accounts payable	**353.8**	399.3
Dividends payable	**32.0**	31.9
Customer deposits	**56.7**	55.5
Accrued taxes	**18.3**	40.0
Accrued interest	**24.8**	37.0
Accrued compensation	**25.5**	53.9
Long-term debt due within one year	**1.0**	1.0
Price risk management	**6.8**	20.6
Gas imbalances	**11.8**	11.1
Fuel clause over recoveries	**4.2**	4.2
Other	**34.4**	38.2
Total current liabilities	**835.6**	988.5
LONG-TERM DEBT	**1,543.3**	1,344.6
COMMITMENTS AND CONTINGENCIES (NOTE 13)		
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued benefit obligations	**159.9**	156.2
Accumulated deferred income taxes	**868.2**	853.6
Accumulated deferred investment tax credits	**20.8**	22.0
Accrued removal obligations, net	**141.1**	139.7
Price risk management	**5.6**	11.3
Other	**42.0**	41.0
Total deferred credits and other liabilities	**1,237.6**	1,223.8
STOCKHOLDERS' EQUITY		
Common stockholders' equity	**758.4**	756.2
Retained earnings	**986.7**	1,005.7
Accumulated other comprehensive loss, net of tax	**(64.3)**	(81.0)
Total stockholders' equity	**1,680.8**	1,680.9
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 5,297.3**	$ 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

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**

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

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

(In millions)	**Three Months Ended March 31, 2008**	2007
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income	**$ 13.0**	$ 17.2
Adjustments to reconcile net income to net cash (used in) provided from operating activities		
Minority interest income	**1.6**	---
Depreciation	**50.7**	48.7
Deferred income taxes and investment tax credits, net	**14.3**	4.1
Stock-based compensation expense	**1.1**	1.0
Price risk management assets	**(2.8)**	32.5
Price risk management liabilities	**6.4**	(10.1)
Other assets	**7.6**	5.9
Other liabilities	**(3.6)**	(1.9)
Change in certain current assets and liabilities		
Accounts receivable, net	**(8.7)**	41.0
Accrued unbilled revenues	**8.5**	5.5
Fuel, materials and supplies inventories	**4.5**	4.1
Gas imbalance assets	**1.0**	(0.8)
Fuel clause under recoveries	**(2.8)**	---
Other current assets	**1.2**	2.6
Accounts payable	**(45.5)**	8.9
Customer deposits	**1.2**	1.8
Accrued taxes	**(20.8)**	(28.6)
Accrued interest	**(12.2)**	(14.0)
Accrued compensation	**(28.4)**	(19.3)
Gas imbalance liabilities	**0.7**	2.0
Fuel clause over recoveries	**---**	30.0
Other current liabilities	**(3.8)**	(4.6)
Net Cash (Used in) Provided from Operating Activities	**(16.8)**	126.0
CASH FLOWS FROM INVESTING ACTIVITIES		

Capital expenditures (less allowance for equity funds used during construction)		**(125.9)**		(119.6)
Proceeds from sale of assets		**0.1**		0.5
Net Cash Used in Investing Activities		**(125.8)**		(119.1)
CASH FLOWS FROM FINANCING ACTIVITIES				
Proceeds from long-term debt		**197.2**		---
Decrease in short-term debt, net		**(29.5)**		---
Issuance of common stock		**0.2**		7.0
Contributions from partners		**0.5**		1.7
Dividends paid on common stock		**(31.9)**		(31.1)
Net Cash Provided from (Used in) Financing Activities		**136.5**		(22.4)
NET DECREASE IN CASH AND CASH EQUIVALENTS		**(6.1)**		(15.5)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD		**8.8**		47.9
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$**	**2.7**	$	32.4

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 Inc. 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 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.

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 March 31, 2008 and December 31, 2007, the results of its operations for the three months ended March 31, 2008 and 2007, and the results of its cash flows for the three months ended March 31, 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 months ended March 31, 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)	**March 31, 2008**	December 31, 2007
Regulatory Assets		
Regulatory asset - SFAS 158	**$ 170.5**	$ 174.6
Deferred storm expenses	**35.0**	35.9
Fuel clause under recoveries	**30.1**	27.3
Deferred pension plan expenses	**22.3**	24.8
Unamortized loss on reacquired debt	**18.6**	18.9
Income taxes recoverable from customers, net	**17.1**	17.4
Red Rock deferred expenses	**14.7**	14.7
McClain Plant deferred expenses	**10.9**	12.4
Cogeneration credit rider under recovery	**0.8**	3.9
Miscellaneous	**0.4**	0.8
Total Regulatory Assets	**$ 320.4**	$ 330.7
Regulatory Liabilities		
Accrued removal obligations, net	**$ 141.1**	$ 139.7
Fuel clause over recoveries	**4.2**	4.2
Deferred gain on sale of assets	**1.0**	1.4
Miscellaneous	**2.7**	2.9
Total Regulatory Liabilities	**$ 149.0**	$ 148.2

For a discussion of proceedings related to the deferred storm expenses and deferred Red Rock expenses, 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 generally accepted accounting priniciples (“GAAP”) purposes also and OG&E will 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 will recover costs from its customers using the weighted-average cost method for inventory beginning January 1, 2008.

The change in accounting for fuel inventory to the weighted-average cost method had no material effect on the amount of fuel expense that the Company recorded for the first quarter of 2008.

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 $23.5 million and $38.2 million, respectively, at March 31, 2008, and non-current Price Risk Management assets and liabilities would be approximately $6.2 million and $41.1 million, respectively, at March 31, 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, Enogex Inc., which was an Oklahoma corporation, converted to Enogex LLC, a Delaware limited liability company, effective April 1, 2008. 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 69 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 initial public 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 period ended March 31, 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 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 expands disclosures about fair value measurements (see Note 4 for a further discussion).

In September 2006, the Emerging Issues Task Force ("EITF") reached a consensus on EITF Issue No. 06-4, "Accounting for Deferred Compensation and Postretirement Benefit Aspects of Endorsement Split-Dollar Life Insurance Arrangements," which states that for an endorsement split-dollar life insurance arrangement that provides a benefit to an employee that extends to postretirement periods, an employer should recognize a liability for future benefits in accordance with SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," (if a postretirement benefit plan exists) or Accounting Principles Board Opinion No. 12 for deferred compensation contracts based on the substantive agreement with the employee. Application of the consensus in EITF 06-4 is effective for fiscal years beginning after December 15, 2007. Entities should recognize the effects of applying the consensus in EITF 06-4 through either: (a) a change in accounting principle through a cumulative effect adjustment to retained earnings or to other components of equity in the statement of financial position as of the beginning of the year of adoption; or (b) a change in accounting principle through retrospective application to all prior periods. The Company adopted this consensus effective January 1, 2008. The adoption of this consensus did not have a material impact on the Company's consolidated financial position or results of operations.

In December 2007, the FASB issued SFAS No. 141 (Revised), "Business Combinations," which is intended to improve the relevance, representational faithfulness and comparability of the information that a reporting entity provides in its financial reports about a business combination and its effects. SFAS No. 141(R) replaces SFAS No. 141, "Business Combinations," and establishes principles and requirements for how the acquirer: (i) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree; (ii) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and (iii) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) applies to all transactions or other events in which an entity obtains control of one or more businesses and combinations achieved without the transfer of consideration. SFAS No. 141(R) also applies to all business entities, including mutual entities that previously used the pooling-of-interests method of accounting for some business combinations. SFAS No. 141(R) does not apply to: (i) the formation of a joint venture; (ii) the acquisition of an asset or a group of assets that does not constitute a business; (iii) a combination between entities or businesses under common control; or (iv) a combination between not-for-profit organizations or the acquisition of a for-profit business by a not-for-profit organization. SFAS No. 141(R) also amends SFAS No. 109, "Accounting for Income Taxes," to require the acquirer to recognize changes in the amount of its deferred tax benefits that are recognizable because of a business combination either in income from continuing operations in the period of the combination or directly in contributed capital, depending on the circumstances. SFAS No. 141(R) is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The provisions of SFAS No. 141(R) are to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. The Company will adopt this new standard effective January 1, 2009. The adoption of this new standard is not expected to have a material impact on the Company's consolidated financial position or results of operations.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements," which is intended to improve the relevance, comparability and transparency of the financial information that a reporting entity provides in its consolidated financial statements by establishing accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS No. 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations. SFAS No. 160 amends Accounting Research Bulletin No. 51, "Consolidated Financial Statements," to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS No. 160 also amends certain of ARB No. 51 consolidation procedures for consistency with the requirements of SFAS No. 141(R) SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The provisions of SFAS No. 160 are to be applied prospectively as of the beginning of the fiscal year in which it is initially adopted, except for the presentation and disclosure requirements, which are to be applied retrospectively for all periods presented. The Company

will adopt this new standard effective January 1, 2009. The adoption of this new standard will change the presentation of noncontrolling interests in the Company's consolidated financial statements.

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities," which requires enhanced disclosures about an entity's derivative and hedging activities and is intended to improve the transparency of financial reporting. SFAS No. 161 applies to all entities. SFAS No. 161 applies to all derivative instruments, including bifurcated derivative instruments and related hedging items accounted for under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and its related interpretations. SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133 with the intent to provide users of financial statements with an enhanced understanding of: (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS No. 161 is effective for fiscal years and interim periods beginning after November 15, 2008. The Company will adopt this new standard effective January 1, 2009. The adoption of this new standard will change the presentation of derivative and hedging activities in the Company's consolidated financial statements.

4. Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157 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 at initial recognition and in all subsequent periods. Therefore, SFAS No. 157 nullifies the guidance in footnote 3 of EITF 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)	**March 31, 2008**	**Level 1**	**Level 2**	**Level 3**
Assets				
Gross derivative assets	**$ 47.2**	$ 14.2	$ 31.5	$ 1.5
Gas imbalance assets	**5.7**	---	5.7	---
Total	**$ 52.9**	$ 14.2	$ 37.2	$ 1.5
Liabilities				
Gross derivative liabilities	**$ 96.3**	$ 14.6	$ 81.7	$ ---
Gas imbalance liabilities	**11.8**	---	11.8	---
Asset retirement obligations	**5.0**	---	---	5.0
Total	**$ 113.1**	$ 14.6	$ 93.5	$ 5.0

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 March 31, 2008.

(In millions)	**March 31, 2008**
Assets	
Gross derivative assets	**$ 47.2**
Less: Amounts held in clearing broker accounts reflected in Other Current Assets	**(17.5)**
Less: Amounts offset under master netting agreements in accordance with FIN 39-1	**(18.9)**
Net Price Risk Management Assets	**$ 10.8**
Liabilities	
Gross derivative liabilities	**$ 96.3**
Less: Amounts held in clearing broker accounts reflected in Other Current Assets	**(17.0)**
Less: Amounts offset under master netting agreements in accordance with FIN 39-1, including amounts netted against collateral payments to counterparties	**(66.9)**
Net Price Risk Management Liabilities	**$ 12.4**

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

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 March 31, 2008	**$** ---

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(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
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 March 31, 2008	**$** ---

Gains and losses (realized and unrealized) included in earnings for the three months ended March 31, 2008 attributable to the change in unrealized gains or losses relating to assets and liabilities held at March 31, 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.

	March 31, 2008		December 31, 2007	
(In millions)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Price Risk Management Assets				
Energy Trading Contracts	**$ 10.8**	**$ 10.8**	$ 8.0	$ 8.0
Price Risk Management Liabilities				
Energy Trading Contracts	**$ 12.4**	**$ 12.4**	$ 30.2	$ 30.2

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 interest rate swaps and 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"). In 2003, the Company adopted, and its shareowners approved, a new Stock Incentive Plan (the "2003 Plan" and together with the 1998 Plan, the "Plans"). The 2003 Plan replaced the 1998 Plan and no further awards will be granted under the 1998 Plan. As under the 1998 Plan, under the 2003 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 2,700,000 shares under the 2003 Plan.

The Company recorded compensation expense of approximately $1.1 million pre-tax ($0.7 million after tax, or $0.01 per basic and diluted share) and $0.8 million pre-tax ($0.5 million after tax, or $0.01 per basic and diluted share) during the three months ended March 31, 2008 and 2007, respectively, related to the Company's share-based payments.

During the three months ended March 31, 2008, the Company awarded 181,892 performance units based on total shareholder return and 60,611 performance units based on earnings per share with a grant date fair value of $33.62 and $29.22, respectively, to certain employees of the Company and its subsidiaries. Also, during the three months ended March

31, 2008, the Company converted 166,477 performance units based on a payout ratio of 147.33 percent of the target number of performance units granted in February 2005.

The Company issues new shares to satisfy stock option exercises. During the three months ended March 31, 2008, there were 7,500 shares 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 $0.2 million and $7.0 million during the three months ended March 31, 2008 and 2007, respectively, related to exercised stock options.

6. Accumulated Other Comprehensive Income (Loss)

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

(In millions)	**March 31, 2008**	December 31, 2007
Defined benefit pension plan and restoration of retirement income plan:		
Net loss, net of tax (($28.9) and ($29.4) pre-tax, respectively)	**$ (17.7)**	$ (18.0)
Prior service cost, net of tax (($1.0) and ($1.1) pre-tax, respectively)	**(0.7)**	(0.8)
Defined benefit postretirement plans:		
Net loss, net of tax (($8.3) and ($8.5) pre-tax, respectively)	**(3.6)**	(3.7)
Net transition obligation, net of tax (($1.0) and ($1.0) pre-tax, respectively)	**(0.7)**	(0.7)
Prior service cost, net of tax (($0.6) and ($0.7) pre-tax, respectively)	**(0.3)**	(0.4)
Deferred hedging losses, net of tax (($64.9) and ($90.9) pre-tax, respectively)	**(39.7)**	(55.7)
Settlement and amortization of cash flow hedge, net of tax (($2.6) and ($2.7) pre-tax, respectively)	**(1.6)**	(1.7)
Total accumulated other comprehensive loss, net of tax	**$ (64.3)**	$ (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 2002. Income taxes are generally allocated to each company in the affiliated group based on its stand-alone taxable income or loss. Federal investment tax credits previously claimed on electric utility property have been deferred and are being amortized to income over the life of the related property. The Company continues to amortize its federal investment tax credits on a ratable basis throughout the year. This ratable amortization results in a larger percentage reconciling item related to these credits during the first quarter when the Company historically experiences decreased book income. The following schedule reconciles the statutory federal tax rate to the effective income tax rate:

	Three Months Ended March 31,	
	2008	2007
Statutory federal tax rate	**35.0%**	35.0%
Intra period effect of OG&E net loss (A)	**5.4**	---
State income taxes, net of federal income tax benefit	**1.5**	2.2
Amortization of net unfunded deferred taxes	**0.9**	0.9
Federal investment tax credits, net	**(5.9)**	(4.9)

Federal renewable energy credit	**(2.5)**	(2.7)
401(k) dividends	**(0.7)**	(0.7)
Medicare Part D subsidy	**(0.3)**	(0.6)
Other	**0.3**	0.3
Effective income tax rate as reported	**33.7%**	29.5%

(A) During the three months ended March 31, 2008, OG&E incurred a pre-tax loss while the Company, on a consolidated basis, recognized a pre-tax gain. Due to the stand-alone tax allocation method prescribed by the FERC, a reconciling item is required in the first quarter 2008 tax rate to properly apply the interim reporting provisions of FASB Interpretation No. 18, "Accounting for Income Taxes in Interim Periods – an interpretation of APB Opinion No. 28" at the consolidated level. This reconciling item will not be required as OG&E recognizes pre-tax income, which is expected to occur later in 2008.

The Company follows the provisions of SFAS No. 109 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 March 31,	
(In millions)	**2008**	2007
Average Common Shares Outstanding		
Basic average common shares outstanding	**91.9**	91.5
Effect of dilutive securities:		
Employee stock options and unvested stock grants	**0.2**	0.3
Contingently issuable shares (performance units)	**0.4**	0.6
Diluted average common shares outstanding	**92.5**	92.4
Anti-dilutive shares excluded from EPS calculation	**---**	---

9. Long-Term Debt

At March 31, 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% - 3.19%	Muskogee Industrial Authority, January 1, 2025	**32.4**
1.35% - 3.24%	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.

Issuance of New Long-Term Debt

In January 2008, OG&E issued $200.0 million of 6.45% senior notes due February 1, 2038. The proceeds from the issuance were used to repay commercial paper borrowings. OG&E entered into two separate treasury lock arrangements, effective November 16, 2007 and November 19, 2007, to hedge interest payments on the first $50.0 million and $25.0 million, respectively, of the long-term debt that was issued in January 2008. These treasury lock agreements were settled on January 29, 2008.

10. Short-Term Debt

The short-term debt balance was approximately $266.3 million and $295.8 million at March 31, 2008 and December 31, 2007, respectively. The following table shows the Company's revolving credit agreements and available cash at March 31, 2008.

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

Entity	Amount Available	Amount Outstanding	Weighted-Average Interest Rate	Maturity
OGE Energy Corp. (A)	$ 600.0	$ 79.7	3.30%	December 6, 2012 (C)
OG&E (B)	400.0	185.8	3.19%	December 6, 2012 (C)
	1,000.0	265.5	3.24%	
Cash	2.7	N/A	N/A	N/A
Total	$ 1,002.7	$ 265.5	3.24%	

(A) This bank facility is available to back up the Company's commercial paper borrowings and to provide revolving credit borrowings. This bank facility c
(B) This bank facility is available to back up OG&E's commercial paper borrowings and to provide revolving credit borrowings. At March 31, 2008, OG&
(C) 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

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 disruption. 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 of the Company 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.

Enogex Credit Facility

On April 1, 2008, Enogex entered into a $250 million unsecured five-year revolving credit facility. Subject to certain limitations, the facility provides Enogex with the option, exercisable annually, to extend the maturity of the facility for an additional year and, upon the expiration of the revolving term, an option to convert the outstanding balance under the facility to a one-year term loan. The facility provides the option for Enogex to increase the borrowing limit by up to an additional $250 million (to a maximum of $500 million) upon the agreement of the lenders (or any additional lender) and the satisfaction of other specified conditions. As of April 30, 2008, there was approximately $25 million outstanding under the facility.

Omnibus Agreement

Concurrent with the entry of the Enogex LLC credit facility on April 1, 2008, Enogex also entered into an omnibus agreement with OGE Energy. The omnibus agreement memorializes Enogex's obligation to reimburse OGE Energy for costs incurred on behalf of Enogex and its subsidiaries. Specifically, Enogex reimburses OGE Energy for:

- the performance of general and administrative services for Enogex and its subsidiaries, such as legal, accounting, treasury, finance, investor relations, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, facilities, fleet management and media services; and

- the payment of certain operating expenses of Enogex and its subsidiaries, including for compensation and benefits of operating personnel.

The maximum reimbursement for general and administrative services is approximately $16.4 million annually for three years, subject to increases based on increases in the Consumer Price Index and subject to further increases in connection with expansions of Enogex's operations through the acquisition or construction of new assets or businesses. The reimbursement for certain operating expenses is not subject to the $16.4 million maximum reimbursement for general and administrative expenses.

Enogex Intercompany Borrowing Agreement

On April 1, 2008, Enogex amended its intercompany borrowing agreement with OGE Energy to decrease the maximum amount permitted to be borrowed by Enogex from $200 million to $100 million. As of April 30, 2008, there was approximately $4 million in outstanding intercompany borrowings

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 was effective for the year ended December 31, 2006 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		Restoration of Retirement Income Plan	
	Three Months Ended March 31,		**Three Months Ended March 31,**	
(In millions)	**2008**	2007	**2008**	2007
Service cost	**$ 4.7**	$ 5.2	**$ 0.1**	$ 0.1
Interest cost	**7.8**	8.0	**0.1**	0.1
Return on plan assets	**(10.9)**	(11.0)	**---**	---
Amortization of net loss	**2.3**	2.6	**0.1**	0.1
Amortization of recognized prior service cost	**0.3**	1.2	**0.2**	0.2
Net periodic benefit cost (A)	**$ 4.2**	$ 6.0	**$ 0.5**	$ 0.5

	Postretirement Benefit Plans	
	Three Months Ended March 31,	
(In millions)	**2008**	2007
Service cost	**$ 0.9**	$ 1.0

Interest cost		**3.3**		3.1
Return on plan assets		**(1.6)**		(1.5)
Amortization of transition obligation		**0.7**		0.7
Amortization of net loss		**1.0**		1.5
Amortization of recognized prior service cost		**0.5**		0.5
Net periodic benefit cost	**$**	**4.8**	$	5.3

(A) In addition to the $4.2 million and $6.0 million in SFAS No. 87, “Employers’ Accounting for Pensions,” net periodic benefit cost recognized during the three months ended March 31, 2008 and 2007, respectively, OG&E also recognized an expense of approximately $2.5 million and $1.1 million, respectively, related to the reversal of a portion of the regulatory asset identified as Deferred Pension Plan Expenses (see Note 1).

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 April 2008, the Company contributed approximately $20 million to its pension plan and currently expects to contribute an additional $30 million to its pension plan during the remainder of 2008. Any expected contributions to the pension plan during 2008 are 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 months ended March 31, 2008 and 2007 primarily included consolidating eliminations. 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 months ended March 31, 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 March 31, 2008 *(In millions)*	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
Operating revenues	**$ 386.4**	**$ 156.9**	**$ 256.8**	**$ 476.9**	**$ ---**	**$ (282.3)**	**$ 994.7**
Cost of goods sold	**240.6**	**122.7**	**195.6**	**471.4**	**---**	**(281.5)**	**748.8**
Gross margin on revenues	**145.8**	**34.2**	**61.2**	**5.5**	**---**	**(0.8)**	**245.9**
Other operation and maintenance (A)	**94.3**	**11.9**	**20.9**	**2.8**	**(3.2)**	**(1.5)**	**125.2**
Depreciation	**36.3**	**4.1**	**8.3**	**---**	**2.0**	**---**	**50.7**
Taxes other than income	**15.9**	**3.5**	**1.1**	**0.2**	**1.2**	**---**	**21.9**
Operating income (loss)	**$ (0.7)**	**$ 14.7**	**$ 30.9**	**$ 2.5**	**$ ---**	**$ 0.7**	**$ 48.1**
Total assets	**$ 3,897.4**	**$ 1,107.2**	**$ 597.5**	**$ 247.8**	**$ 2,011.1**	**$ (2,563.7)**	**$ 5,297.3**

(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 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.

Three Months Ended March 31, 2007 *(In millions)*	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
Operating revenues	$ 340.7	$ 59.1	$ 165.6	$ 462.2	$ ---	$ (146.1)	$ 881.5
Cost of goods sold	199.9	29.1	123.7	459.5	---	(145.3)	666.9
Gross margin on revenues	140.8	30.0	41.9	2.7	---	(0.8)	214.6
Other operation and maintenance	74.2	10.4	16.0	2.2	(3.2)	(0.8)	98.8
Depreciation	35.4	4.4	6.9	---	2.0	---	48.7
Taxes other than income	15.2	3.4	0.9	0.2	1.2	---	20.9

Operating income	$ 16.0	$ 11.8	$ 18.1	$ 0.3	$ ---	$ ---	$ 46.2
Total assets	$ 3,612.9	$ 1,440.8	$ 844.6	$ 187.9	$ 1,970.2	$ (3,197.1)	$ 4,859.3

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.

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. Additionally, in March 2008, OERI reached an agreement to release to a third party 10,000 Dth/day of its remaining capacity beginning in April 2008 through December 2012. OERI's new demand fee obligations, net of this turn back, release agreement 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.

Environmental Laws and Regulations

OG&E

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. A decision by the court is expected by June 2008. 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. An Oklahoma rule that would apply only to new generating units is expected to be proposed by the Oklahoma Department of Environmental Quality ("ODEQ") 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 includes 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 does not meet the requirements of the regional haze rules. On November 16, 2007, the ODEQ notified OG&E that additional analysis will be required before the OG&E alternative plan can be accepted. As required by the ODEQ, OG&E has initiated the additional analysis with a projected completion date of June 1, 2008. Until a compliance plan is approved by the EPA, which is expected by December 31, 2008, the costs of compliance, including capital expenditures, cannot be estimated by the Company with a reasonable degree of certainty. Based on the information currently available to the Company, the Company would expect that the costs of its original alternative plan would be substantially higher than its original estimate of $470 million for the alternative plan. The cost to comply with the regional haze regulations could vary substantially based on the interpretation of the requirements by the ODEQ and the EPA, the availability of alternative control measures to achieve more cost effective visibility improvements, the cost and availability of materials, labor force, equipment and the specific design criteria for OG&E’s generating units. 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”). On March 12, 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 make 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 problem. 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 the Company’s operations.

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 Matters

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. In the settlement of its 2004 Section 311 rate case, the Company agreed to move from a system-wide fuel percentage to zonal fuel percentages. Accordingly, in all of the annual fuel filings made subsequent to the FERC's acceptance of the 2004 rate case settlement, the Company has filed for fixed 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 the expiration or termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act, an order from the FERC authorizing the contemplated transactions, 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. In March 2008, the waiting period for the Hart-Scott-Rodino Antitrust Improvements Act ended and the filing was concluded with no action taken. OG&E filed an application with the FERC and the OCC in March 2008 asking the OCC to approve the prudency of the transactions and an appropriate reasonable recovery mechanism. The OCC rules provide that the OCC has up to 240 days to issue an order determining OG&E's pre-approval request. Absent a settlement, the earliest OG&E expects an order from the OCC is November 2008. There can be no assurances that the transactions will be completed or as to its 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 that are currently reflected in Deferred Charges and Other Assets on the Company's Condensed Consolidated Balance Sheets. Specifically, OG&E requested authorization to sell approximately $14.7 million of its sulphur dioxide ("SO2") 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 SO2 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 February 2008, the OCC issued a procedural schedule with a settlement conference on May 2, 2008 and a hearing scheduled for May 7, 2008. 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 $14.7 million in deferred costs. The OCC Staff proposed the 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 SO2 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 are included as part of the regulatory asset balance of approximately $35.0 million at March 31, 2008 (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 and, at that time, the administrative law judge delayed the May 7, 2008 hearing to allow the parties further time to discuss a settlement. OG&E will pursue a settlement for the recovery of the Red Rock costs and the ice storm costs. If a settlement cannot be reached, the matter would proceed to hearing and OG&E would expect to receive an order from the OCC in this matter by the end of 2008.

OG&E Arkansas Rate Case Filing

Beginning in early 2008, OG&E began developing a rate case filing for the Arkansas jurisdiction. OG&E expects to make a rate case filing in Arkansas by 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.

Renewables Proposal

OG&E expects to file an application in mid-May with the OCC requesting pre-approval to construct a transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma. This transmission line is a critical first step to increased wind development in western Oklahoma. In the application, OG&E will request authorization to implement a recovery rider to be effective when the transmission line goes in service which is expected in the first half of 2010. Finally, the application will request the OCC to approve new renewable tariff offerings to OG&E's Oklahoma customers.

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 additionally filed protests. Enogex responded to data requests from the FERC.

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. The parties are currently in settlement negotiations. 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, the Company submitted: (i) a compliance filing containing the specified revisions to the Company'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 Southwest Power Pool at market-based rates. On February 6, 2007, OG&E and OERI submitted to the FERC a change in status report notifying the FERC that OG&E has placed into service OG&E's Centennial wind farm, a wind farm with a nameplate capacity rating of 120 MW. OG&E and OERI explained that adding this capacity was not material to the FERC's grant of market-based rate status to OG&E and OERI. On March 9, 2007, the FERC accepted OG&E's and OERI's change of status filing. 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.

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

Introduction

OGE Energy Corp. (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 Inc. and its subsidiaries ("Enogex") are 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 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 69 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 period ended March 31, 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.

Summary of Operating Results

Quarter ended March 31, 2008 as compared to quarter ended March 31, 2007

Prior to January 1, 2008, Enogex had engaged in natural gas marketing through OERI. In connection with the proposed initial public offering of common units of the Partnership, on January 1, 2008, Enogex distributed the stock of OERI to OGE Energy. Accordingly, in the discussion below regarding the results of Enogex, the results of OERI are only included for the three months ended March 31, 2007.

The Company reported net income of approximately $13.0 million, or $0.14 per diluted share, during the three months ended March 31, 2008, as compared to approximately $17.2 million, or $0.19 per diluted share, during the three months ended March 31, 2007. The change in net income of approximately $4.2 million, or $0.05 per diluted share, during the three months ended March 31, 2008 as compared to the same period in 2007 was primarily due to:

- a decrease in net income at OG&E of approximately $13.2 million, or $0.14 per diluted share of the Company's common stock, during the three months ended March 31, 2008 as compared to the same period in 2007 primarily due to higher operation and maintenance expense and higher interest expense partially offset by a higher gross margin on revenues ("gross margin") and a higher income tax benefit;
- an increase in net income at Enogex of approximately $7.0 million, or $0.07 per diluted share of the Company's common stock, during the three months ended March 31, 2008 as compared to the same period in 2007 primarily due to a higher gross margin in the transportation and storage and gathering and processing segments partially offset by higher operation and maintenance

expense and higher income tax expense. Net income for Enogex during the three months ended March 31, 2007 included approximately $0.2 million, or less than $0.01 per diluted share, attributable to OERI;

- net income at OERI of approximately $1.7 million, or $0.02 per diluted share of the Company's common stock, during the three months ended March 31, 2008; and
- net income at OGE Energy of approximately $0.1 million, or less than $0.01 per diluted share of the Company's common stock, during the three months ended March 31, 2008 as compared to a net loss of approximately $0.2 million, or less than $0.01 per diluted share, during the same period in 2007 primarily due to a higher income tax benefit due to a higher pre-tax loss during the three months ended March 31, 2008 partially offset by higher other expense related to the Company's deferred compensation plan and restoration of retirement income plan.

OERI's net income during the three months ended March 31, 2008 was approximately $1.7 million, which included a net loss of approximately $1.0 million resulting from recording hedges associated with various transportation contracts at market value on March 31, 2008. The offsetting gains from physical utilization of the transportation capacity are expected to be realized during the second and third quarters of 2008.

Recent Developments and 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 the expiration or termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act, an order from the FERC authorizing the contemplated transactions, 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. In March 2008, the waiting period for the Hart-Scott-Rodino Antitrust Improvements Act ended and the filing was concluded with no action taken. OG&E filed an application with the FERC and the OCC in March 2008 asking the OCC to approve the prudency of the transactions and an appropriate reasonable recovery mechanism. The OCC rules provide that the OCC has up to 240 days to issue an order determining OG&E's pre-approval request. Absent a settlement, the earliest OG&E expects an order from the OCC is November 2008. There can be no assurances that the transactions will be completed or as to its 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 that are currently reflected in Deferred Charges and Other Assets on the Company's Condensed Consolidated Balance Sheets. Specifically, OG&E requested authorization to sell approximately $14.7 million of its sulphur dioxide ("SO2") 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 SO2 allowances were to be credited to taxpayers. Any portion of the $14.7 million of deferred costs that the OCC does not approve for recovery by

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OG&E will be expensed. In February 2008, the OCC issued a procedural schedule with a settlement conference on May 2, 2008 and a hearing scheduled for May 7, 2008. 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 $14.7 million in deferred costs. The OCC Staff proposed the 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 SO2 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 are included as part of the regulatory asset balance of approximately $35.0 million at March 31, 2008 (see Note 1 of Notes to Condensed Consolidated Financial Statements), 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 and, at that time, the administrative law judge delayed the May 7, 2008 hearing to allow the parties further time to discuss a settlement. OG&E will pursue a settlement for the recovery of the Red Rock costs and the ice storm costs. If a settlement cannot be reached, the matter would proceed to hearing and OG&E would expect to receive an order from the OCC in this matter by the end of 2008.

2008 Outlook

The Company previously disclosed in its Annual Report on Form 10-K for the year ended December 31, 2007 ("2007 Form 10-K") that its 2008 earnings guidance was $223 million to $242 million of net income, or $2.40 to $2.60 per diluted share as shown in the table below. The Company has reaffirmed 2008 earnings guidance, excluding any gains on asset sales and assuming approximately 93.1 million average diluted shares outstanding, cash flow from operations of between $483 million and $502 million and an effective tax rate of 33.5 percent. Though the consolidated earnings guidance has not changed, the guidance for the Company's individual business segments have been revised. The change in earnings guidance between segments is due to an increase in the projected earnings at Enogex and a decrease in projected earnings at OG&E.

	Earnings guidance per 2007 10-K		Revised earnings guidance	
(In millions, except per share data)	Dollars	Diluted EPS	Dollars	Diluted EPS
OG&E	$145 - $155	$1.56 - $1.66	$140 - $150	$1.50 - $1.61
Enogex	$83 - $91	$0.89 - $0.98	$88 - $101	$0.95 - $1.08
Holding Company	($5) - ($4)	($0.05) - ($0.04)	($5) - ($4)	($0.05) - ($0.04)
Total	$223 - $242	$2.40 - $2.60	$223 - $242	$2.40 - $2.60

Key assumptions for 2008 are:

As shown above, OG&E's earnings guidance has been decreased from $145 million to $155 million, or $1.56 to $1.66 per diluted share, to $140 million to $150 million, or $1.50 to $1.61 per diluted share. As explained below, this decrease is attributable to higher operating expenses which includes the one-time, non-cash charge of $9.5 million to correct the over-capitalization in prior years of various operation and maintenance expenses. Key factors and assumptions underlying this guidance include:

OG&E

- Normal weather patterns are experienced for the remainder of the year;
- Gross margin on weather-adjusted, retail electric sales increases approximately two percent remains unchanged;
- Operating expenses of approximately $545 million compared to $536 million projected in previous guidance;
- Interest expense of approximately $77 million remains unchanged;
- An effective tax rate of approximately 31.1 percent remains unchanged; and
- Capital expenditures for investment in OG&E's generation, transmission and distribution system of approximately $765 million in 2008, which includes capital expenditures in the amount of approximately $435 million associated with OG&E's planned acquisition of the Redbud generating plant.

OG&E has significant seasonality in its earnings. OG&E typically shows minimal earnings or slight losses in the first and fourth quarters with a majority of earnings in the third quarter due to the seasonal nature of air conditioning demand.

Enogex

As shown above, Enogex's earnings guidance has been increased from $83 million to $91 million, or $0.89 to $0.98 per diluted share, to $88 million to $101 million, or $0.95 to $1.08 per diluted share. Earnings before Interest, Taxes, Depreciation and Amortization is between $232 million to $253 million. Key factors and assumptions underlying this guidance include:

- Total Enogex anticipated gross margin of approximately $388 million to $409 million as compared to approximately $376 million to $390 million assumed in the previous 2008 earnings guidance. The revised guidance includes:
  - Transportation and storage gross margin contribution of approximately $141 million remains unchanged;
  - Gathering and processing gross margin contribution of approximately $247 million to $268 million as compared to approximately $235 million to $249 million assumed in the previous 2008 earnings guidance primarily due to increased commodity price assumptions. Key factors affecting the revised gathering and processing gross margin are:
    - Assumed increase of eight percent in gathered volumes over 2007 remains unchanged;
    - Commodity price assumptions are below;

	2007 10-K		Revised	
	Low Guidance	High Guidance	Low Guidance	High Guidance
Natural Gas Price ($ per MMBtu)	$7.64	$7.25	$9.30	$8.72
Weighted Average Natural Gas Liquids Price ($ per gallon)	$1.20	$1.27	$1.35	$1.45
Realized Weighted Average Commodity Spreads ($ per MMBtu)	$5.48	$6.09	$6.21	$7.12

- The realized commodity spread takes into account that 59 percent of processing volumes that bear price risk are hedged;
- Operating expenses of approximately $204 million compared to $201 million in the previous 2008 guidance;
- Interest expense of approximately $35 million in 2008 as compared to $30 million in the previous 2008 guidance; and
- Capital expenditures for investment in Enogex's pipeline system of approximately $323 million in 2008 as compared to $292 million in the previous 2008 guidance; and
- Increases in operating expenses, interest expense and capital expenditures are primarily due to additional growth projects on the Enogex system compared to the previous guidance reported in the Company's 2007 Form 10-K.

Reconciliation of EBITDA to net cash provided from operating activities

(In millions)	**Twelve Months Ended December 31, 2008**
Net cash provided by operating activities	**$ 151.1**
Interest expense, net	**33.4**
Changes in operating working capital which provided (used) cash:	
Accounts receivable	**4.0**
Accounts payable	**54.2**
Other, including changes in noncurrent assets and liabilities	**0.1**
EBITDA	**$ 242.8**

Reconciliation of EBITDA to net income

(In millions)	Twelve Months Ended December 31, 2008
Net Income	**$ 94.5**
Add:	
Interest expense, net	**33.4**
Income tax expense	**60.2**
Depreciation	**54.7**
EBITDA	**$ 242.8**

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For a discussion of the reasons for the use of EBITDA, as well as the limitations of EBITDA as an analytical tool, see "Enogex's Non-GAAP Financial Measures" below.

Holding Company

As shown above, the projected loss at the holding company is between $4 million and $5 million, or $0.04 to $0.05 per diluted share, remains unchanged. The projected net loss is primarily due to interest expense relating to long and short-term debt borrowings and a projected loss of approximately $2 million, or $0.02 per diluted share, in the marketing business. In connection with the proposed initial public offering of limited partner interests of 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 and OERI's projected results for 2008 are included in the holding company's projected loss for 2008.

Results of Operations

The following discussion and analysis presents factors that affected the Company's consolidated results of operations for the three months ended March 31, 2008 as compared to the same period in 2007 and the Company's consolidated financial position at March 31, 2008. Due to seasonal fluctuations and other factors, the operating results for the three months ended March 31, 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 following information should be read in conjunction with the Condensed Consolidated Financial Statements and Notes thereto. Known trends and contingencies of a material nature are discussed to the extent considered relevant.

	Three Months Ended March 31,	
(In millions, except per share data)	**2008**	2007
Operating income	**$ 48.1**	$ 46.2
Net income	**$ 13.0**	$ 17.2
Basic average common shares outstanding	**91.9**	91.5
Diluted average common shares outstanding	**92.5**	92.4
Basic earnings per average common share	**$ 0.14**	$ 0.19
Diluted earnings per average common share	**$ 0.14**	$ 0.19
Dividends declared per share	**$ 0.3475**	$ 0.34

In reviewing its consolidated operating results, the Company believes that it is appropriate to focus on operating income as reported in its Condensed Consolidated Statements of Income as operating income indicates the ongoing profitability of the Company excluding the cost of capital and income taxes.

Operating Income (Loss) by Business Segment

	Three Months Ended March 31,	
(In millions)	**2008**	2007
OG&E (Electric Utility)	**$ (0.7)**	$ 16.0
Enogex (Natural Gas Pipeline)		
Transportation and storage	**14.7**	11.8
Gathering and processing	**30.9**	18.1
OERI (Natural Gas Marketing) (A)	**2.5**	0.3
Other Operations (B)	**0.7**	---
Consolidated operating income	**$ 48.1**	$ 46.2

(A) In connection with the proposed initial public offering of common units of the Partnership, on January 1, 2008, Enogex distributed the stock of OERI to OGE Energy, and as a result, OERI is no longer a subsidiary of Enogex.

(B) Other Operations primarily includes consolidating eliminations.

The following operating income analysis by business segment includes intercompany transactions that are eliminated in the Condensed Consolidated Financial Statements.

OG&E

	Three Months Ended March 31,	
(Dollars in millions)	**2008**	2007
Operating revenues	**$ 386.4**	$ 340.7
Cost of goods sold	**240.6**	199.9
Gross margin on revenues	**145.8**	140.8
Other operation and maintenance	**94.3**	74.2
Depreciation	**36.3**	35.4
Taxes other than income	**15.9**	15.2
Operating income (loss)	**(0.7)**	16.0
Interest income	**0.3**	---
Other income	**2.3**	1.3
Other expense	**0.7**	0.6
Interest expense	**19.5**	15.6
Income tax benefit	**7.0**	0.8
Net income (loss)	**$ (11.3)**	$ 1.9
Operating revenues by classification		
Residential	**$ 146.4**	$ 134.7
Commercial	**89.4**	76.2
Industrial	**46.6**	41.3
Oilfield	**32.6**	27.8
Public authorities and street light	**36.1**	31.3
Sales for resale	**15.3**	13.9
System sales revenues	**366.4**	325.2
Off-system sales revenues	**12.3**	9.3
Other	**7.7**	6.2
Total operating revenues	**$ 386.4**	$ 340.7
MWH (A) sales by classification (in millions)		
Residential	**2.2**	2.0
Commercial	**1.4**	1.4
Industrial	**1.0**	1.0
Oilfield	**0.7**	0.7
Public authorities and street light	**0.6**	0.6
Sales for resale	**0.4**	0.3
System sales	**6.3**	6.0
Off-system sales	**0.2**	0.3
Total sales	**6.5**	6.3
Number of customers	**765,165**	758,244
Average cost of energy per KWH (B) – cents		
Natural gas	**7.598**	7.343
Coal	**1.074**	1.104
Total fuel	**3.118**	2.610
Total fuel and purchased power	**3.440**	2.946
Degree days (C)		
Heating		
Actual	**1,814**	1,669
Normal	**1,982**	1,963
Cooling		
Actual	**12**	43
Normal	**9**	8

(A) Megawatt-hour.
(B) Kilowatt-hour.
(C) Degree days are calculated as follows: The high and low degrees of a particular day are added together and then averaged. If the calculated average is above 65 degrees, then the difference between the calculated average and 65 is expressed as cooling degree days, with each degree of difference equaling one cooling degree day. If the calculated average is below 65 degrees, then the difference between the calculated average and 65 is expressed as heating degree days, with each degree of difference equaling one heating degree day. The daily calculations are then totaled for the particular reporting period.

Quarter ended March 31, 2008 as compared to quarter ended March 31, 2007

Operating Income

OG&E’s operating income decreased approximately $16.7 million during the three months ended March 31, 2008 as compared to the same period in 2007 primarily due to higher operation and maintenance expenses partially offset by higher gross margin.

Gross Margin

Gross margin was approximately $145.8 million during the three months ended March 31, 2008 as compared to approximately $140.8 million during the same period in 2007, an increase of approximately $5.0 million, or 3.6 percent. The gross margin increased primarily due to:

- new customer growth in OG&E’s service territory, which increased the gross margin by approximately $2.1 million;
- higher rates from the Centennial wind farm rider and Arkansas rate case, which increased the gross margin by approximately $2.0 million; and
- increased peak demand and related revenues by non-residential customers in OG&E’s service territory, which increased the gross margin by approximately $1.1 million.

Cost of goods sold for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was approximately $186.6 million during the three months ended March 31, 2008 as compared to approximately $159.7 million during the same period in 2007, an increase of approximately $26.9 million, or 16.8 percent, primarily due to higher natural gas generation due to an outage at one of OG&E’s coal fired plants. OG&E’s electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for OG&E and its customers. Purchased power costs were approximately $53.8 million during the three months ended March 31, 2008 as compared to approximately $40.2 million during the same period in 2007, an increase of approximately $13.6 million, or 33.8 percent, primarily due to increased purchases within the energy imbalance market.

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component included in the cost-of-service for ratemaking, are passed through to OG&E’s customers through automatic fuel adjustment clauses. The automatic fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC. The OCC, the APSC and the FERC have authority to review the appropriateness of gas transportation charges or other fees OG&E pays to Enogex.

Operating Expenses

Other operation and maintenance expenses were approximately $94.3 million during the three months ended March 31, 2008 as compared to approximately $74.2 million during the same period in 2007, an increase of approximately $20.1 million, or 27.1 percent. The increase in other operation and maintenance expenses was primarily due to:

- an increase of approximately $9.5 million due to a correction of the over-capitalization of certain payroll, benefits, other employee related costs and overhead costs in previous years, as discussed in Note 12 of Notes to Condensed Consolidated Financial Statements;
- increased labor costs in the first quarter of 2008 as compared to the first quarter of 2007, when a significant portion of the labor costs were capitalized due to the January 2007 ice storm, which increased operation and maintenance expenses by approximately $3.1 million;
- an increase of approximately $3.5 million in contract services and approximately $2.1 million in materials and supplies attributable to overhauls at one of OG&E's power plants; and
- an increase of approximately $1.7 million in professional services primarily due to higher legal expenses in the first quarter of 2008 as compared to the same period in 2007.

These increases in other operating and maintenance expenses were partially offset by a decrease of approximately $2.2 million due to an increase in collections on uncollectible accounts.

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Additional Information

Other Income. Other income includes, among other things, contract work performed, non-operating rental income and miscellaneous non-operating income. Other income was approximately $2.3 million during the three months ended March 31, 2008 as compared to approximately $1.3 million during the same period in 2007, an increase of approximately $1.0 million, or 76.9 percent. The increase in other income was primarily due to an increase of approximately $0.5 million related to the guaranteed flat bill tariff resulting from more customers participating in this plan.

Interest Expense. Interest expense was approximately $19.5 million during the three months ended March 31, 2008 as compared to $15.6 million during the same period in 2007, an increase of approximately $3.9 million, or 25.0 percent. The increase in interest expense was primarily due to:

- an increase of approximately $2.4 million related to interest expense recorded on treasury lock agreements which OG&E entered into related to the issuance of long-term debt in January 2008; and
- an increase of approximately $1.8 million in interest expense related to the issuance of $200 million of long-term debt by OG&E in January 2008.

Income Tax Benefit. Income tax benefit was approximately $7.0 million during the three months ended March 31, 2008 as compared to approximately $0.8 million during the same period in 2007, an increase of approximately $6.2 million, primarily due to lower pre-tax income in the first quarter of 2008 as compared to the same period in 2007.

Enogex

	Transportation	Gathering

Three Months Ended	and	and		
March 31, 2008	Storage	Processing	Eliminations	Total
(In millions)				
Operating revenues	**$ 156.9**	**$ 256.8**	**$ (147.0)**	**$ 266.7**
Cost of goods sold	**122.7**	**195.6**	**(147.0)**	**171.3**
Gross margin on revenues	**34.2**	**61.2**	**---**	**95.4**
Other operation and maintenance	**11.9**	**20.9**	**---**	**32.8**
Depreciation	**4.1**	**8.3**	**---**	**12.4**
Taxes other than income	**3.5**	**1.1**	**---**	**4.6**
Operating income	**$ 14.7**	**$ 30.9**	**$ ---**	**$ 45.6**

	Transportation	Gathering			
Three Months Ended	and	and			
March 31, 2007	Storage	Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	$ 59.1	$ 165.6	$ 462.2	$ (129.1)	$ 557.8
Cost of goods sold	29.1	123.7	459.5	(128.3)	484.0
Gross margin on revenues	30.0	41.9	2.7	(0.8)	73.8
Other operation and maintenance	10.4	16.0	2.2	(0.8)	27.8
Depreciation	4.4	6.9	---	---	11.3
Taxes other than income	3.4	0.9	0.2	---	4.5
Operating income	$ 11.8	$ 18.1	$ 0.3	$ ---	$ 30.2

Operating Data

	Three Months Ended March 31,	
	2008	2007
New well connects (includes wells behind central receipt points) (A)	**85**	99
New well connects (excludes wells behind central receipt points)	**39**	46
Gathered volumes – TBtu/d (B)	**1.07**	0.99
Incremental transportation volumes – TBtu/d (C)	**0.40**	0.39
Total throughput volumes – TBtu/d	**1.47**	1.38
Natural gas processed – TBtu/d	**0.61**	0.52
Natural gas liquids sold (keep-whole) – million gallons	**53**	51
Natural gas liquids sold (purchased for resale) – million gallons	**40**	27
Natural gas liquids sold (percent-of-liquids) – million gallons	**5**	4
Total natural gas liquids sold – million gallons	**98**	82
Average sales price per gallon	**$ 1.354**	$ 0.860
Realized commodity spreads	**$ 7.03**	$ 3.20

(A) Includes wells behind central receipt points (as reported to management by third parties). A central receipt point is a single receipt point into a gathering line where a producer aggregates the volumes from one or more wells and delivers them into the gathering system at a single meter site.

(B) Trillion British thermal units per day.

(C) Incremental transportation volumes consist of natural gas moved only on the transportation pipeline.

Quarter ended March 31, 2008 as compared to quarter ended March 31, 2007

Operating Income

Enogex's operating income increased approximately $15.4 million during the three months ended March 31, 2008 as compared to the same period in 2007 primarily due to higher gross margins in the transportation and storage and gathering and processing segments partially offset by higher operating expenses.

Gross Margin

Enogex's consolidated gross margin increased approximately $21.6 million during the three months ended March 31, 2008 as compared to the same period in 2007. The increase resulted from a higher gross margin in the transportation and storage business ($4.2 million) and the gathering and processing business ($19.3 million). Gross margin during the three months ended March 31, 2007 included approximately $2.7 million attributable to OERI.

The transportation and storage business contributed approximately $34.2 million of Enogex's consolidated gross margin during the three months ended March 31, 2008 as compared to approximately $30.0 million during the same period in 2007, an increase of approximately $4.2 million, or 14.0 percent. The transportation operations contributed approximately $25.7 million of Enogex's consolidated gross margin during the three months ended March 31, 2008. The storage operations contributed approximately $8.5 million of Enogex's consolidated gross margin during the three months ended March 31, 2008. The transportation and storage gross margin increased primarily due to:

- a decreased imbalance liability, net of fuel recoveries and natural gas length positions, in the transportation operations during the three months ended March 31, 2008, which increased the gross margin by approximately $6.3 million;
- increased storage demand fees due to entering into new contracts during the three months ended March 31, 2008 with more favorable terms, which increased the gross margin by approximately $1.7 million; and
- increased crosshaul revenues due to entering into a new contract during the three months ended March 31, 2008, which increased the gross margin by approximately $1.4 million.

These increases in the transportation and storage gross margin were partially offset by:

- lower gross margins on operational storage hedges during the three months ended March 31, 2008 as compared to the same period in 2007, which decreased the gross margin by approximately $2.8 million;

- a decrease in demand fees in the transportation operations during the three months ended March 31, 2008, due to a renegotiated contract, which decreased the gross margin by approximately $1.3 million; and

- a decrease of approximately $1.3 million in Enogex's over-recovered position in the East Zone in its transportation operations during the three months ended March 31, 2007 which resulted in a gain with no comparable item during the three months ended March 31, 2008, as a result of Enogex being in an under-recovered position under its FERC-approved fuel tracker.

The gathering and processing business contributed approximately $61.2 million of Enogex's consolidated gross margin during the three months ended March 31, 2008 as compared to approximately $41.9 million during the same period in 2007, an increase of approximately $19.3 million, or 46.1 percent. The gathering operations contributed approximately $18.9 million of Enogex's consolidated gross margin during the three months ended March 31, 2008. The processing operations contributed approximately $42.3 million of Enogex's consolidated gross margin during the three months ended March 31, 2008. The gathering and processing gross margin increased primarily due to:

- an increase in keep-whole margins associated with the processing operations during the three months ended March 31, 2008 as compared to the same period in 2007 primarily due to higher commodity spreads and a slight increase in keep-whole gallons, which increased the gross margin by approximately $12.8 million;
- increased condensate margin associated with the processing operations due to higher prices during the three months ended March 31, 2008 as compared to the same period in 2007, which increased the gross margin by approximately $5.4 million;
- sales of residue gas, condensate and additional retained natural gas liquids associated with the processing operations of the Atoka joint venture, which began operations in August 2007, which increased the gross margin by approximately $2.7 million;
- increased gross margin on percent-of-liquids contracts associated with the processing operations due to favorable pricing for natural gas liquids, which increased the gross margin by approximately $1.9 million;
- higher compression and dehydration fees associated with the gathering operations resulting from new business in 2007, which increased the gross margin by approximately $0.9 million;
- an increase from new volumes processed under fixed fee processing contracts, which increased the gross margin by approximately $0.9 million;
- increased low pressure gathering fees associated with new projects, including Atoka, which increased the gross margin by approximately $0.9 million; and
- increased gross margin on percent-of-liquids contracts associated with the processing operations due to new volumes from the Atoka processing plant, which increased the gross margin by approximately $0.7 million.

These increases in the gathering and processing gross margin were partially offset an increase in the imbalance liability, net of fuel recoveries and natural gas length positions during the three months ended March 31, 2008, which decreased the gross margin by approximately $5.8 million.

Operating Expenses

As shown above, the increase in Enogex's operating income during the three months ended March 31, 2008 as compared to the same period in 2007 was attributable primarily to the $21.6 million increase described above in the consolidated gross margin, as the aggregate of other operation and maintenance expenses, depreciation expense and taxes other than income was approximately $6.2 million higher during the three months ended March 31, 2008 as compared to the same period in 2007. The variance in depreciation expense on both a consolidated basis and by segment reflects differing levels of depreciable plant in service. The $5.0 million increase in other operation and maintenance expenses on a consolidated basis was primarily due to an increase in expenses for system projects during the three months ended March 31, 2008 as compared to the same period in 2007.

Specifically, by segment, other operation and maintenance expenses for the transportation and storage business were approximately $1.5 million, or 14.4 percent, higher during the three months March 31, 2008 as compared to the same period in 2007 primarily due to:

- an increase of approximately $2.6 million in contract professional services and materials and supplies expense due to an increase in system projects during the three months ended March 31, 2008;
- higher salaries, wages and other employee benefits expense of approximately $1.6 million primarily due to higher incentive compensation and hiring additional employees to support business growth; and
- higher allocations from OGE Energy for overhead costs of approximately $1.0 million.

These increases were partially offset by higher allocations for overhead costs of approximately $3.2 million to the other Enogex segments, which decreased operation and maintenance expenses for the transportation and storage segment.

Other operation and maintenance expenses for the gathering and processing business were approximately $4.9 million, or 30.6 percent, higher during the three months ended March 31, 2008 as compared to the same period in 2007 primarily due to higher allocations for overhead costs of approximately $3.4 million during the three months ended March 31, 2008.

Other operation and maintenance expenses for the marketing business were approximately $2.2 million during the three months ended March 31, 2007.

Enogex Consolidated Information

Interest Income. Enogex's consolidated interest income was approximately $1.3 million during the three months ended March 31, 2008 as compared to approximately $2.6 million during the same period in 2007, a decrease of approximately $1.3 million, or 50.0 percent, primarily due to a decrease in interest earned as the balance of advances to OGE Energy decreased due to dividends and capital expenditures.

Other Expense. Enogex's consolidated other expense was approximately $1.7 million during the three months ended March 31, 2008 as compared to approximately $0.1 million during the same period in 2007, an increase of approximately $1.6 million, primarily due to the minority interest in the Atoka joint venture, which began operations in August 2007.

Income Tax Expense. Enogex's consolidated income tax expense was approximately $14.7 million during the three months ended March 31, 2008 as compared to approximately $9.4 million during the same period in 2007, an increase of approximately $5.3 million, or 56.3 percent, primarily due to higher pre-tax income in the first quarter of 2008 as compared to the same period in 2007.

Timing Items. For the three months ended March 31, 2007, Enogex's consolidated net income was approximately $15.5 million, which included a loss of approximately $4.1 million at OERI resulting from recording hedges associated with the Cheyenne Plains transportation contract at market value on March 31, 2007. The offsetting gains from physical utilization of the transportation capacity were realized during the remainder of 2007.

Enogex's Non-GAAP Financial Measures

Enogex has included in this Form 10-Q the non-GAAP financial measure EBITDA. Enogex defines EBITDA as net income before interest, income taxes and depreciation. EBITDA is used as a supplemental financial measure by external users of the Company's financial statements such as investors, commercial banks and others, to assess:

- the financial performance of Enogex’s assets without regard to financing methods, capital structure or historical cost basis;
- Enogex’s operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

The economic substance behind the use of EBITDA is to measure the ability of Enogex’s assets to generate cash sufficient to pay interest costs, support indebtedness and pay dividends to OGE Energy.

Enogex provides a reconciliation of EBITDA to its most directly comparable financial measures as calculated and presented in accordance with generally accepted accounting principles (“GAAP”). The GAAP measures most directly comparable to EBITDA are net cash provided from operating activities and net income. The non-GAAP financial measure of EBITDA should not be considered as an alternative to GAAP net cash provided from operating activities and GAAP net income. EBITDA is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. EBITDA should not be considered in isolation or as a substitute for analysis of Enogex’s results as reported under GAAP. Because EBITDA excludes some, but not all, items that affect net income and net cash provided from operating activities and is defined differently by different companies in Enogex’s industry, Enogex’s definition of EBITDA may not be comparable to similarly titled measures of other companies.

To compensate for the limitations of EBITDA as an analytical tool, Enogex believes it is important to review the comparable GAAP measures and understand the differences between the measures.

Reconciliation of EBITDA to net cash provided from operating activities

	Three Months Ended March 31,	
(In millions)	**2008**	2007
Net cash provided by operating activities (A)	**$ 18.5**	$ 49.7
Interest expense, net	**6.8**	5.5
Changes in operating working capital which provided (used) cash:		
Accounts receivable	**7.2**	(24.5)
Accounts payable	**16.9**	19.5
Other, including changes in noncurrent assets and liabilities	**7.0**	(8.5)
EBITDA (B)	**$ 56.4**	$ 41.7

(A) Approximately $55.9 million of net cash provided by operating activities during the three months ended March 31, 2007 was attributable to OERI.

(B) Approximately $0.4 million of EBITDA during the three months ended March 31, 2007 was attributable to OERI.

Reconciliation of EBITDA to net income

	Three Months Ended March 31,	
(In millions)	**2008**	2007
Net income (C)	**$ 22.5**	$ 15.5
Add:		
Interest expense, net	**6.8**	5.5
Income tax expense	**14.7**	9.4
Depreciation	**12.4**	11.3
EBITDA	**$ 56.4**	$ 41.7

(C) Approximately $0.2 million of net income during the three months ended March 31, 2007 was attributable to OERI.

There are no results for OERI included in the above tables for the three months ended March 31, 2008 because, as of January 1, 2008, Enogex distributed the stock of OERI to OGE Energy.

OERI

	Three Months Ended March 31,	
	2008	2007
(In millions)		
Operating revenues	**$ 476.9**	$ 462.2
Cost of goods sold	**471.4**	459.5
Gross margin on revenues	**5.5**	2.7
Other operation and maintenance	**2.8**	2.2

Taxes other than income	**0.2**	0.2
Operating income	**$ 2.5**	$ 0.3

Quarter ended March 31, 2008 as compared to quarter ended March 31, 2007

Operating Income

OERI's operating income increased approximately $2.2 million during the three months ended March 31, 2008 as compared to the same period in 2007 primarily due to an increase in gross margin partially offset by an increase in other operation and maintenance expense.

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Gross Margin

Gross margin was approximately $5.5 million during the three months ended March 31, 2008 as compared to approximately $2.7 million during the same period in 2007, an increase of approximately $2.8 million. The gross margin increased primarily due to:

- realized gains of approximately $5.2 million in the first quarter of 2008 on economic storage hedges previously deferred as well as losses of approximately $3.3 million in 2007 on economic storage hedges entered into during 2007 as a result of recording these hedges at market value, which increased the gross margin by approximately $8.5 million; and

- decreased losses on economic hedges associated with various transportation contracts from recording these hedges at market value on March 31, 2008 as compared to March 31, 2007, which increased the gross margin by approximately $2.1 million.

These increases in the gross margin were partially offset by:

- decreased gains on physical sales of natural gas storage inventory activity in addition to higher storage fees paid by OERI, which decreased the gross margin by approximately $4.2 million; and
- decreased gains from origination and other marketing and trading activity during the three months ended March 31, 2008 as compared to the same period in 2007, which decreased the gross margin by approximately $2.2 million.

Operating Expenses

Other operation and maintenance expenses were approximately $2.8 million during the three months ended March 31, 2008 as compared to approximately $2.2 million during the same period in 2007, an increase of approximately $0.6 million, or 27.3 percent. The increase in other operation and maintenance expenses was primarily due to higher allocations from OGE Energy and its affiliates.

Additional Information

Income Tax Expense. Income tax expense was approximately $1.0 million during the three months ended March 31, 2008 as compared to approximately $0.1 million during the same period in 2007, an increase of approximately $0.9 million, primarily due to higher pre-tax income in the first quarter of 2008 as compared to the same period in 2007.

Timing Items. For the three months ended March 31, 2008, OERI’s net income was approximately $1.7 million, which included a net loss of approximately $1.0 million resulting from recording hedges associated with various transportation contracts at market value on March 31, 2008. The offsetting gains from physical utilization of the transportation capacity are expected to be realized during the second and third quarters of 2008.

For the three months ended March 31, 2007, OERI's net income was approximately $0.2 million, which included a loss of approximately $4.1 million resulting from recording hedges associated with the Cheyenne Plains transportation contract at market value on March 31, 2007. The offsetting gains from physical utilization of the transportation capacity are expected to be realized during the remainder of 2007.

Financial Condition

The balance of Short-Term Debt was approximately $266.3 million and $295.8 million at March 31, 2008 and December 31, 2007, respectively, a decrease of approximately $29.5 million, or 10.0 percent, primarily due to the repayment of outstanding commercial paper borrowings from the proceeds of the issuance of $200 million of long-term debt by OG&E in January 2008 partially offset by increased commercial paper borrowings to meet the daily operational needs of the Company.

The balance of Accounts Payable was approximately $353.8 million and $399.3 million at March 31, 2008 and December 31, 2007, respectively, a decrease of approximately $45.5 million, or 11.4 percent, primarily due to payments made in the first quarter of 2008 related to the December 2007 ice storm.

The balance of Accrued Taxes was approximately $18.3 million and $40.0 million at March 31, 2008 and December 31, 2007, respectively, a decrease of approximately $21.7 million, or 54.3 percent, primarily due to ad valorem tax payments made in the first quarter of 2008.

The balance of Accrued Compensation was approximately $25.5 million and $53.9 million at March 31, 2008 and December 31, 2007, respectively, a decrease of approximately $28.4 million, or 52.7 percent, primarily due to the annual payment for incentive compensation made in the first quarter of 2008.

The balance of current Price Risk Management Liabilities was approximately $6.8 million and $20.6 million at March 31, 2008 and December 31, 2007, respectively, a decrease of approximately $13.8 million, or 67.0 percent, primarily due to the increased value of cash flow hedges of natural gas liquids sales and corresponding keep-whole natural gas purchases entered into during 2007 partially offset by refunds of collateral payments to the counterparties during the first quarter of 2008.

The balance of Long-Term Debt was approximately $1.5 billion and $1.3 billion at March 31, 2008 and December 31, 2007, respectively, an increase of approximately $198.7 million, or 14.8 percent, primarily due to the issuance of $200 million in long-term debt in January 2008.

The balance of Accumulated Other Comprehensive Loss was approximately $64.3 million and $81.0 million at March 31, 2008 and December 31, 2007, respectively, a decrease of approximately $16.7 million, or 20.6 percent, primarily due to hedging gains at Enogex during the first quarter of 2008.

Off-Balance Sheet Arrangements

Except as discussed below, there have been no significant changes in the Company's off-balance sheet arrangements from those discussed in the Company's 2007 Form 10-K.

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.

Liquidity and Capital Requirements

The Company's primary needs for capital are related to acquiring or constructing new facilities and replacing or expanding existing facilities at OG&E and Enogex. Other working capital requirements are primarily related to maturing debt, operating lease obligations, hedging activities, natural gas storage, delays in recovering unconditional fuel purchase obligations and fuel clause under and over recoveries. The Company generally meets its cash needs through a combination of cash generated from operations, short-term borrowings (through a combination of bank borrowings and commercial paper) and permanent financings.

Cash Flows

Three Months Ended March 31*(In millions)*	**2008**	2007
Net cash (used in) provided from operating activities	**$ (16.8)**	$ 126.0
Net cash used in investing activities	**(125.8)**	(119.1)
Net cash provided from (used in) financing activities	**136.5**	(22.4)

The reduction of approximately $142.8 million in net cash provided from operating activities during the three months ended March 31, 2008 as compared to the same period in 2007 primarily related to an increase in accounts receivable primarily related to an increase in natural gas prices during the first quarter of 2008 partially offset by a decrease in the volume of natural gas sales and the timing of collection of outstanding receivables during the first quarter of 2007, in addition to decreases in accounts payable primarily due to payments by OG&E in the first quarter of 2008 related to the December 2007 ice storm and fuel clause over recoveries in the first quarter of 2008. The increase of approximately $6.7 million in net cash used in investing activities during the three months ended March 31, 2008 as compared to the same period in 2007 primarily related to higher levels of capital expenditures. The increase of approximately $158.9 million in net cash provided from financing activities during the three months ended March 31, 2008 as compared to the same period in 2007 primarily

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related to proceeds received from issuance of long-term debt in the first quarter of 2008 partially offset by the epayment of short-term debt.

Future Capital Requirements

Capital Expenditures

The Company's current 2008 to 2013 construction program includes continued investment in OG&E's distribution, generation and transmission system and Enogex's transportation, storage, gathering and processing assets. In the Company's 2007 Form 10-K, the Company's estimates of capital expenditures were approximately: 2008 - $1.1 billion (approximately $434.5 million are related to the proposed acquisition of the Redbud power plant), 2009 - $613.9 million, 2010 - $668.1 million, 2011 - $653.4 million, 2012 - $670.8 million and 2013 - $654.1 million. These estimates included approximately $12.0 million, $22.5 million, $83.0 million, $97.3 million, $93.8 million and $69.6 million, respectively, for environmental expenditures associated with Best Available Retrofit Technology ("BART") requirements. As discussed in Note 13 of Notes to Condensed Consolidated Financial Statements, due to an opinion from the U.S. Environmental Protection Agency ("EPA") that OG&E's proposed initial compliance plan would not satisfy the applicable requirements, OG&E is undertaking additional analysis. Until a compliance plan is approved by the EPA, the costs of compliance, including capital expenditures, cannot be estimated by the Company with a reasonable degree of certainty. Based on information currently available to the Company, the Company would expect that the costs of its initial compliance plan would be substantially higher than its original estimate of $470 million. Due to this uncertainty regarding BART costs, the Company has excluded any BART costs from its updated capital expenditure estimates. Therefore, the Company's current estimates of capital expenditures, without any BART costs, are approximately: 2008 - $1.1 billion (approximately $434.5 million are related to the proposed acquisition of the Redbud power plant), 2009 - $553.4 million, 2010 - $582.5 million, 2011 - $591.7 million, 2012 - $593.2 million and 2013 - $584.5 million. These capital expenditures also exclude expenditures related to the proposed transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma.

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 April 2008, the Company contributed approximately $20 million to its pension plan and currently expects to contribute an additional $30 million to its pension plan during the remainder of 2008. Any remaining expected contributions to the pension plan during 2008 are 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.

Future Sources of Financing

Management expects that cash generated from operations, proceeds from the sale of assets, proceeds from the issuance of long and short-term debt and proceeds from the sale of common stock to the public through the Company's Automatic Dividend Reinvestment and Stock Purchase Plan or other offerings will be adequate over the next three years to meet anticipated cash needs. The Company utilizes short-term borrowings (through a combination of bank borrowings and commercial paper) to satisfy temporary working capital needs and as an interim source of financing capital expenditures until permanent financing is arranged.

Issuance of New Long-Term Debt

In January 2008, OG&E issued $200.0 million of 6.45% senior notes due February 1, 2038. The proceeds from the issuance were used to repay commercial paper borrowings.

Short-Term Debt

Short-term borrowings generally are used to meet working capital requirements. At March 31, 2008 and December 31, 2007, respectively, the Company had approximately $265.5 million and $295.0 million, respectively, in outstanding commercial paper borrowings. Also, OG&E has the necessary regulatory approvals to incur up to $800 million in short-term borrowings at any time for a two-year period beginning January 1, 2007 and ending December 31, 2008.

On April 1, 2008, Enogex entered into a $250 million unsecured five-yearrevolving credit facility. Subject to certain limitations, the facility provides Enogex with the option, exercisable annually, to extend the maturity of the facility for an additional year and, upon the expiration of the revolving term, an option to convert the outstanding balance under the

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facility to a one-year term loan**.** The facility provides the option for Enogex to increase the borrowing limit by up to an additional $250 million (to a maximum of $500 million) upon the agreement of the lenders (or any additional lender) and the satisfaction of other specified conditions. As of April 30, 2008, there was $25 million outstanding under the facility. See Note 10 of Notes to Condensed Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

Critical Accounting Policies and Estimates

The Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements contain information that is pertinent to Management's Discussion and Analysis. In preparing the Condensed Consolidated Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Condensed Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the Company's Condensed Consolidated Financial Statements. However, the Company believes it has taken reasonable, but conservative, positions where assumptions and estimates are used in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised is in the valuation of pension plan assumptions, impairment estimates, contingency reserves, asset retirement obligations, fair value and cash flow hedges, regulatory assets and liabilities, unbilled revenues for OG&E, operating revenues for Enogex, natural gas purchases for Enogex, the allowance for uncollectible accounts receivable and the valuation of energy purchase and sale contracts. The selection, application and disclosure of the Company's critical accounting estimates have been discussed with the Company's Audit Committee and are discussed in detail in Management's Discussion and Analysis of Financial Condition and Results of Operations in the Company's 2007 Form 10-K.

Accounting Pronouncements

See Notes 3 and 4 of Notes to Condensed Consolidated Financial Statements for a discussion of recent accounting pronouncements that are applicable to the Company.

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. See Note 1 of Notes to Condensed Consolidated Financial Statements for a further discussion.

Electric Competition; Regulation

OG&E and Enogex have been and will continue to be affected by competitive changes to the utility and energy industries. Significant changes already have occurred and additional changes are being proposed to the wholesale electric market. Although retail restructuring efforts in Oklahoma and Arkansas were postponed in 2001, if such efforts were renewed, retail competition and the unbundling of regulated energy service could have a significant financial impact on the Company due to an impairment of assets, a loss of retail customers, lower profit margins and/or increased costs of capital. Any such restructuring also could have a significant impact on the Company's consolidated financial position, results of operations and cash flows. The Company cannot predict when it will be subject to changes in legislation or regulation, nor can it predict the impact of these changes on the Company's consolidated financial position, results of operations or cash flows. The Company believes that the prices for electricity and the quality and reliability of the Company's service currently place us in a position to compete effectively in the energy market. OG&E is also subject to competition in various degrees from state-owned electric systems, municipally-owned electric systems, rural electric cooperatives and, in certain respects, from other private utilities, power marketers and cogenerators. OG&E has a franchise to serve in more than 270 towns and cities throughout its service territory.

Commitments and Contingencies

Except as disclosed otherwise in this Form 10-Q and the Company's 2007 Form 10-K, 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. See Notes 13 and 14 of Notes to Condensed Consolidated Financial Statements in this Form 10-Q and Notes 16 and 17 of Notes to Consolidated Financial Statements and Item 3 of Part I of the 2007 Form 10-K for a discussion of the Company's commitments and contingencies.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Except as set forth below, the market risks set forth in Part II, Item 7A of the Company's 2007 Form 10-K appropriately represent, in all material respects, the market risks affecting the Company.

Commodity Price Risk

The market risks inherent in the Company's market risk sensitive instruments, positions and anticipated commodity transactions are the potential losses in value arising from adverse changes in the commodity prices to which the Company is exposed. These market risks can be classified as trading, which includes transactions that are entered into voluntarily to capture subsequent changes in commodity prices, or non-trading, which includes the exposure some of the Company's assets have to commodity prices.

Trading Activities

The trading activities are conducted throughout the year subject to daily and monthly trading stop loss limits set by the Risk Oversight Committee. Those trading stop loss limits currently are $2.5 million. The daily loss exposure from trading activities is measured primarily using value-at-risk ("VaR"), which estimates the potential losses the trading activities could incur over a specified time horizon and confidence level. The VaR limit set by the Risk Oversight Committee for the Company's trading activities, assuming a 95 percent confidence level, currently is $1.5 million. These limits are designed to mitigate the possibility of trading activities having a material adverse effect on the Company's operating income.

A sensitivity analysis has been prepared to estimate the Company's exposure to market risk created by trading activities. The value of trading positions is a summation of the fair values calculated for each net commodity position based upon quoted market prices. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 10 percent adverse change in quoted market prices over the next 12 months. The result of this analysis, which may differ from actual results, is as follows at March 31, 2008.

(In millions)	Trading
Commodity market risk, net	$ 0.1

Non-Trading Activities

The prices of natural gas, natural gas liquids and natural gas liquids processing spreads are subject to fluctuations resulting from changes in supply and demand. The changes in these prices have a direct effect on the compensation the Company receives for operating some of its assets. To partially reduce non-trading commodity price risk, the Company hedges, through the utilization of derivatives and other forward transactions, the effects these market fluctuations have on the Company's operating income. Because the commodities covered by these hedges are substantially the same commodities that the Company buys and sells in the physical market, no special studies other than monitoring the degree of correlation between the derivative and cash markets are deemed necessary.

A sensitivity analysis has been prepared to estimate the Company's exposure to the market risk of the Company's non-trading activities. The Company's daily net commodity position consists of natural gas inventories, commodity purchase and sales contracts, financial and commodity derivative instruments and anticipated natural gas processing spreads and fuel recoveries. Quoted market prices are not available for all of the Company's non-trading positions, therefore, the value of non-trading positions is a summation of the forecasted values calculated for each commodity based upon internally generated forward price curves. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 10 percent adverse change in such prices over the next 12 months. The result of this analysis, which may differ from actual results, is as follows at March 31, 2008.

(In millions)	Non-Trading
Commodity market risk, net	$ 12.2

Management may designate certain derivative instruments for the purchase or sale of physical commodities, purchase or sale of electric power and fuel procurement as normal purchases and normal sales contracts under the provisions of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." Normal purchases and normal sales contracts are not recorded in Price Risk Management assets or liabilities in the Condensed Consolidated Balance Sheets and earnings recognition is recorded in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales to (i) commodity contracts for the purchase and sale of natural gas; (ii) commodity contracts for the sale of natural gas liquids produced by its subsidiary, Enogex Products LLC; (iii) electric power contracts by OG&E; and (iv) fuel procurement by OG&E.

Credit Risk

Credit risk includes the risk that counterparties that owe the Company money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, the Company may be forced to enter into alternative arrangements. In that event, the Company's financial results could be adversely affected and the Company could incur losses.

For Enogex and OERI, credit risk is the risk of financial loss if counterparties fail to perform their contractual obligations. Enogex and OERI maintain credit policies with regard to its counterparties that management believes minimize overall credit risk. These policies include the evaluation of a potential counterparty's financial position (including credit rating, if available), collateral requirements under certain circumstances and the use of standardized agreements which provide for the netting of cash flows associated with a single counterparty. Enogex and OERI also monitor the financial position of existing counterparties on an ongoing basis. At March 31, 2008, Oneok Inc. and its subsidiaries (“Oneok”) had credit lines totaling approximately $140 million which represented approximately 11 percent of the total credit lines Enogex and OERI had extended to counterparties. At April 1, 2008, the amount of Oneok’s credit line was reduced to approximately $90 million.

Item 4. Controls and Procedures.

The Company maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission (“SEC”) rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer (“CEO”) and chief financial officer (“CFO”), allowing timely decisions regarding required disclosure. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of the Company’s management, including the CEO and CFO, of the effectiveness of the Company’s disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15(d)-15(e) under the Securities Exchange Act of 1934), the CEO and CFO have concluded that the Company’s disclosure controls and procedures are effective.

No change in the Company’s internal control over financial reporting has occurred during the Company’s most recently completed fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company’s internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934).

PART II. OTHER INFORMATION

Item 1. Legal Proceedings.

Reference is made to Part I, Item 3 of the Company’s 2007 Form 10-K for a description of certain legal proceedings presently pending. Except as set forth in Notes 13 and 14 of Notes to Condensed Consolidated Financial Statements in this Form 10-Q, there are no new significant cases to report against the Company or its subsidiaries and there have been no material changes in the previously reported proceedings.

Item 1A. Risk Factors.

There have been no significant changes in the Company’s risk factors from those discussed in the Company’s 2007 Form 10-K.

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

The shares indicated below represent shares of Company common stock purchased on the open market by the trustee for the Company's Stock Ownership and Retirement Savings Plan and reflect shares purchased with employee contributions as well as the portion attributable to the Company's matching contributions.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan
1/1/08 – 1/31/08	95,600	$ 33.37	N/A	N/A
2/1/08 – 2/29/08	20,900	$ 33.56	N/A	N/A
3/1/08 – 3/31/08	56,500	$ 31.69	N/A	N/A

N/A – not applicable

Item 6. Exhibits.

Exhibit No.	Description
10.01	Credit Agreement dated as of April 1, 2008, by and among Enogex LLC, the Lenders thereto, Wachovia Bank, National Association, as Administrative Agent, The Royal Bank of Scotland plc, as Syndication Agent, and JPMorgan Chase Bank, N.A, Mizuho Corporate Bank, LTD. and Union Bank of California, as Co-Documentation Agents. (Filed as Exhibit 10.01 to OGE Energy Corp.'s Form 8-K filed April 7, 2008 (File No. 1 12579) and incorporated by reference herein).
10.02	Amendment No. 1 to the Company's 2003 Annual Incentive Compensation Plan.
10.03	OGE Energy Corp. Supplemental Executive Retirement Plan, as amended and restated.
10.04	OGE Energy Corp. Restoration of Retirement Income Plan, as amended and restated.
10.05	OGE Energy Corp. Deferred Compensation Plan, as amended and restated.
10.06	Amendment No. 3 to the Company's 2003 Stock Incentive Plan.
10.07	Amendment to the Company's Stock Incentive Plan.
10.08	Form of Amended and Restated Employment Agreement with current officers of the Company.
10.09	Form of Employment Agreement with future officers of the Company.
18.01	Letter from Ernst & Young LLP related to a change in accounting principle.
31.01	Certifications Pursuant to Rule 13a-14(a)/15d-14(a) As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification Pursuant to 18 U.S.C. Section 1350 As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

SIGNATURE

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

OGE ENERGY CORP.
(Registrant)

By /s/ Scott Forbes
Scott Forbes
Controller – Chief Accounting Officer

May 7, 2008