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

FORM 10-Q

(Mark One)
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 2006

OR

[ ] 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 ___

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):
Large Accelerated Filer _X_ Accelerated Filer ___ Non-Accelerated Filer ___

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ___ No_X_

As of June 30, 2006, 90,972,169 shares of common stock, par value $0.01 per share, were outstanding.

OGE ENERGY CORP.

FORM 10-Q

FOR THE QUARTER ENDED JUNE 30, 2006

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Item 1. Financial Statements.

OGE ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	**June 30, 2006**	December 31, 2005
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ ---**	$ 26.4
Accounts receivable, less reserve of $4.6 and $3.7, respectively	**433.4**	591.4
Accrued unbilled revenues	**62.8**	41.8
Fuel inventories	**79.1**	63.6
Materials and supplies, at average cost	**56.1**	56.5
Price risk management	**43.6**	116.5
Gas imbalances	**16.2**	32.0
Accumulated deferred tax assets	**14.7**	14.3
Fuel clause under recoveries	**8.8**	101.1
Recoverable take or pay gas charges	---	4.9
Prepayments and other	**20.5**	25.1
Total current assets	**735.2**	1,073.6
OTHER PROPERTY AND INVESTMENTS, at cost	**31.3**	29.2
PROPERTY, PLANT AND EQUIPMENT		
In service	**6,086.7**	5,996.3
Construction work in progress	**196.5**	101.8
Other	**4.9**	3.1
Total property, plant and equipment	**6,288.1**	6,101.2
Less accumulated depreciation	**2,591.2**	2,568.7
Net property, plant and equipment	**3,696.9**	3,532.5
In service of discontinued operations	---	60.6
Less accumulated depreciation	---	25.7
Net property, plant and equipment of discontinued operations	---	34.9
Net property, plant and equipment	**3,696.9**	3,567.4
DEFERRED CHARGES AND OTHER ASSETS		
Income taxes recoverable from customers, net	**32.3**	32.8
Intangible asset - unamortized prior service cost	**32.8**	32.8
Prepaid benefit obligation	**133.5**	90.2
Price risk management	**1.9**	9.0
McClain Plant deferred expenses	**21.8**	24.9
Unamortized loss on reacquired debt	**20.7**	21.3
Unamortized debt issuance costs	**9.6**	8.1
Other	**6.2**	7.2
Deferred charges and other assets of discontinued operations	---	2.4
Total deferred charges and other assets	**258.8**	228.7

TOTAL ASSETS	**$ 4,722.2**	$ 4,898.9

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

OGE ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)
(Unaudited)

(In millions)	**June 30, 2006**	December 31, 2005
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 58.2**	$ 30.0
Accounts payable	**243.7**	510.4
Dividends payable	**30.2**	30.1
Customers' deposits	**50.2**	47.8
Accrued taxes	**70.0**	67.1
Accrued interest	**37.5**	31.9
Tax collections payable	**15.8**	8.7
Accrued compensation	**34.3**	40.3
Long-term debt due within one year	**3.0**	---
Price risk management	**37.8**	109.5
Gas imbalances	**21.8**	36.0
Fuel clause over recoveries	**45.4**	---
Provision for payments of take or pay gas	---	8.9
Other	**31.7**	29.9
Total current liabilities	**679.6**	950.6
LONG-TERM DEBT	**1,346.7**	1,350.8
COMMITMENTS AND CONTINGENCIES (NOTE 17)		
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued pension and benefit obligations	**245.6**	234.5
Accumulated deferred income taxes	**834.4**	807.1
Accumulated deferred investment tax credits	**29.3**	31.7
Accrued removal obligations, net	**120.4**	114.2
Price risk management	**0.2**	10.7
Asset retirement obligation	**4.7**	3.6
Other	**18.3**	19.9
Total deferred credits and other liabilities	**1,252.9**	1,221.7
STOCKHOLDERS' EQUITY		
Common stockholders' equity	**729.0**	715.5
Retained earnings	**808.7**	750.5
Accumulated other comprehensive loss, net of tax	**(94.7)**	(90.2)
Total stockholders' equity	**1,443.0**	1,375.8
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 4,722.2**	$ 4,898.9

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

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

	Three Months Ended	**Six Months Ended**

(In millions, except per share data)	June 30, 2006	2005	June 30, 2006	2005
OPERATING REVENUES				
Electric Utility operating revenues	**$ 444.7**	$ 394.1	**$ 818.7**	$ 695.2
Natural Gas Pipeline operating revenues	**489.6**	936.1	**1,225.4**	1,900.3
Total operating revenues	**934.3**	1,330.2	**2,044.1**	2,595.5
COST OF GOODS SOLD				
Electric Utility cost of goods sold	**217.6**	202.2	**443.5**	367.2
Natural Gas Pipeline cost of goods sold	**432.6**	892.1	**1,095.2**	1,813.8
Total cost of goods sold	**650.2**	1,094.3	**1,538.7**	2,181.0
Gross margin on revenues	**284.1**	235.9	**505.4**	414.5
Other operation and maintenance	**103.0**	99.8	**208.5**	196.6
Depreciation	**45.5**	43.5	**90.4**	88.4
Taxes other than income	**17.9**	16.8	**37.0**	35.0
OPERATING INCOME	**117.7**	75.8	**169.5**	94.5
OTHER INCOME (EXPENSE)				
Other income	**1.7**	1.0	**8.4**	2.6
Other expense	**(9.6)**	(1.0)	**(10.8)**	(2.6)
Net other expense	**(7.9)**	---	**(2.4)**	---
INTEREST INCOME (EXPENSE)				
Interest income	**1.6**	0.1	**3.1**	2.1
Interest on long-term debt	**(22.2)**	(19.7)	**(43.9)**	(38.7)
Allowance for borrowed funds used during construction	**1.9**	0.8	**2.9**	1.4
Interest on short-term debt and other interest charges	**0.1**	(1.7)	**(1.9)**	(3.3)
Net interest expense	**(18.6)**	(20.5)	**(39.8)**	(38.5)
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	**91.2**	55.3	**127.3**	56.0
INCOME TAX EXPENSE	**33.3**	19.5	**45.3**	18.5
INCOME FROM CONTINUING OPERATIONS	**57.9**	35.8	**82.0**	37.5
DISCONTINUED OPERATIONS				
Income from discontinued operations	**58.8**	4.4	**60.1**	10.2
Income tax expense	**23.0**	1.7	**23.5**	3.9
Income from discontinued operations	**35.8**	2.7	**36.6**	6.3
NET INCOME	**$ 93.7**	$ 38.5	**$ 118.6**	$ 43.8
BASIC AVERAGE COMMON SHARES OUTSTANDING	**90.9**	90.2	**90.8**	90.1
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**92.0**	90.8	**91.9**	90.6
BASIC EARNINGS PER AVERAGE COMMON SHARE				
Income from continuing operations	**$ 0.64**	$ 0.40	**$ 0.91**	$ 0.42
Income from discontinued operations, net of tax	**0.39**	0.03	**0.40**	0.07
NET INCOME	**$ 1.03**	$ 0.43	**$ 1.31**	$ 0.49
DILUTED EARNINGS PER AVERAGE COMMON SHARE				
Income from continuing operations	**$ 0.63**	$ 0.39	**$ 0.89**	$ 0.41
Income from discontinued operations, net of tax	**0.39**	0.03	**0.40**	0.07
NET INCOME	**$ 1.02**	$ 0.42	**$ 1.29**	$ 0.48
DIVIDENDS DECLARED PER SHARE	**$ 0.3325**	$ 0.3325	**$ 0.6650**	$ 0.6650

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

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

(In millions)	Six Months Ended June 30, 2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES		
Net income from continuing operations	**$ 82.0**	$ 37.5
Adjustments to reconcile net income from continuing operations to net cash provided from operating activities		
Depreciation	**90.4**	88.4
Deferred income taxes and investment tax credits, net	**15.0**	24.4
Allowance for equity funds used during construction	**(0.2)**	---
Gain on sale of assets	**(0.6)**	(0.2)
Loss on retirement of fixed assets	**6.8**	---
Stock-based compensation expense	**2.0**	---

Excess tax benefit on stock-based compensation	**1.1**	---
Price risk management assets	**80.0**	(15.8)
Price risk management liabilities	**(87.0)**	9.5
Other assets	**(42.5)**	(12.4)
Other liabilities	**12.7**	(4.8)
Change in certain current assets and liabilities		
Accounts receivable, net	**251.1**	69.4
Accrued unbilled revenues	**(21.0)**	(32.7)
Fuel, materials and supplies inventories	**(15.3)**	34.3
Gas imbalance asset	**15.8**	(28.8)
Fuel clause under recoveries	**92.3**	16.1
Other current assets	**9.5**	7.5
Accounts payable	**(266.7)**	(85.7)
Customers' deposits	**2.4**	(1.6)
Accrued taxes	**2.9**	13.1
Accrued interest	**5.6**	(0.5)
Gas imbalance liability	**(14.2)**	(4.8)
Fuel clause over recoveries	**45.4**	---
Other current liabilities	**(2.5)**	5.3
Net Cash Provided from Operating Activities	**265.0**	118.2
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	**(244.1)**	(143.6)
Proceeds from sale of assets	**1.7**	0.7
Other investing activities	**(0.1)**	---
Net Cash Used in Investing Activities	**(242.5)**	(142.9)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from long-term debt	**217.5**	---
Retirement of long-term debt	**---**	(34.3)
(Decrease) increase in short-term debt, net	**(191.8)**	97.7
Issuance of common stock	**6.1**	7.9
Dividends paid on common stock	**(60.3)**	(59.9)
Net Cash (Used in) Provided from Financing Activities	**(28.5)**	11.4
DISCONTINUED OPERATIONS		
Net cash (used in) provided from operating activities	**(20.2)**	4.2
Net cash used in investing activities	**(0.2)**	(1.0)
Net cash used in financing activities	**---**	(0.8)
Net Cash (Used in) Provided from Discontinued Operations	**(20.4)**	2.4
NET DECREASE IN CASH AND CASH EQUIVALENTS	**(26.4)**	(10.9)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**26.4**	11.1
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ ---**	$ 0.2

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

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

1. Summary of Significant Accounting Policies

Organization

OGE Energy Corp. (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 two business segments, the Electric Utility and the Natural Gas Pipeline segments. 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 and 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.

The operations of the Natural Gas Pipeline segment are conducted through Enogex Inc. and its subsidiaries ("Enogex") and consist of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas; and (iii) the marketing of natural gas. The vast majority of Enogex's natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of

Oklahoma. In May 2006, Enogex Gas Gathering, L.L.C. ("Gathering"), a wholly-owned subsidiary of Enogex Inc., sold certain gas gathering assets in the Kinta, Oklahoma, area (see Note 8 for a further discussion).

The Company allocates operating costs to its affiliates based on several factors. Operating costs directly related to specific affiliates are assigned to those affiliates. Where more than one affiliate benefits from certain expenditures, the costs are shared between those affiliates receiving the benefits. Operating costs incurred for the benefit of all affiliates are allocated among the affiliates, 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 Securities and Exchange Commission. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been condensed or omitted pursuant to such rules and regulations; however, the Company believes that the disclosures are adequate to prevent the information presented from being misleading.

In the opinion of management, all adjustments necessary to fairly present the consolidated financial position of the Company at June 30, 2006 and December 31, 2005, the results of its operations for the three and six months ended June 30, 2006 and 2005, and the results of its cash flows for the six months ended June 30, 2006 and 2005, have been included and are of a normal recurring nature.

Due to seasonal fluctuations and other factors, the operating results for the three and six months ended June 30, 2006 are not necessarily indicative of the results that may be expected for the year ending December 31, 2006 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 Form 10-K for the year ended December 31, 2005.

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 the Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards ("SFAS") No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 provides that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment.

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

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

(In millions)	**June 30, 2006**	December 31, 2005
Regulatory Assets		
Income taxes recoverable from customers, net	**$ 32.3**	$ 32.8
McClain Plant deferred expenses	**21.8**	24.9
Unamortized loss on reacquired debt	**20.7**	21.3
Fuel clause under recoveries	**8.8**	101.1
Recoverable take or pay gas charges	**---**	4.9
Cogeneration credit rider under recovery	**---**	3.7
Miscellaneous	**0.9**	0.5
Total Regulatory Assets	**$ 84.5**	$ 189.2
Regulatory Liabilities		
Accrued removal obligations, net	**$ 120.4**	$ 114.3
Fuel clause over recoveries	**45.4**	---
Deferred gain on sale of assets	**3.1**	3.8
Cogeneration credit rider over recovery	**3.0**	---
Total Regulatory Liabilities	**$ 171.9**	$ 118.1

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.

Stock-Based Compensation

The Company adopted SFAS No. 123 (Revised), "Share-Based Payment," effective January 1, 2006, which required the Company to measure and recognize the cost of employee services received in exchange for an award of equity instruments based on the grant date fair value of the award. See Note 3 for a further discussion related to the Company's stock-based compensation. The following table reflects pro forma net income and income per average common share for the three and six months ended June 30, 2005 had the Company elected to adopt the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," for options granted under the Company's stock-based employee compensation plans. For purposes of this pro forma disclosure, the value of the options was determined using a Black-Scholes option pricing formula and amortized to expense over the options' vesting periods. Pro forma information is not included for the three and six months ended June 30, 2006 as all share-based payments have been accounted for under SFAS No. 123(R).

(In millions, except per share data)	Three Months Ended June 30, 2005	Six Months Ended June 30, 2005
Net income, as reported	$ 38.5	$ 43.8
Add:		
Stock-based employee compensation expense included in reported net income, net of related tax effects	---	---
Deduct:		
Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	0.2	0.3
Pro forma net income	$ 38.3	$ 43.5
Income per average common share		
Basic – as reported	$ 0.43	$ 0.49
Diluted – as reported	$ 0.42	$ 0.48
Basic and Diluted – pro forma	$ 0.42	$ 0.48

Reclassifications

Certain prior year amounts have been reclassified on the Condensed Consolidated Financial Statements to conform to the 2006 presentation.

2. Accounting Pronouncements

In February 2006, the FASB issued SFAS No. 155, "Accounting for Certain Hybrid Instruments – an amendment of FASB Statements 133 and 140," which amends SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" and SFAS No. 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities." SFAS No. 155 resolves issues addressed in SFAS No. 133 Implementation Issue No. D1, "Application of Statement 133 to Beneficial Interests in Securitized Financial Assets." SFAS No. 155, among other things, permits fair value remeasurement for any hybrid financial instrument that contains an embedded derivative that otherwise would require bifurcation, clarifies which interest-only strips and principal-only strips are not subject to the requirements of SFAS No. 133 and clarifies that concentrations of credit risk in the form of subordination are not embedded derivates. SFAS No. 155 is effective for all financial instruments acquired or issued after the beginning of an entity's fiscal year beginning after September 15, 2006. The Company will adopt this new standard effective January 1, 2007. Management does not expect the adoption of this statement to have a material impact on the Company's consolidated financial position or results of operations.

In March 2006, the FASB issued SFAS No. 156, "Accounting for Servicing of Financial Assets – an amendment of FASB Statement 140," which amends SFAS No. 140 with respect to accounting for separately recognized servicing assets and servicing liabilities. SFAS No. 156, among other things, requires an entity to recognize a servicing asset or servicing liability each time it undertakes an obligation to service a financial asset by entering into a service contract in certain situations, requires all separately recognized servicing assets and servicing liabilities to be initially measured at fair value if practicable and permits an entity to choose either the amortization method or the fair value method for each class of separately recognized servicing assets and servicing liabilities. SFAS No. 156 is effective as of the beginning of an entity's fiscal year beginning after September 15, 2006. The Company will adopt this new standard effective January 1, 2007. Management does not expect the adoption of this statement to have a material impact on the Company's consolidated financial position or results of operations.

In July 2006, the FASB issued FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109," which clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements in accordance with SFAS No. 109, "Accounting for Income Taxes." This interpretation prescribes a recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. This interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition. This interpretation is effective for fiscal years beginning after December 15, 2006. The Company will adopt this new interpretation effective January 1, 2007. Management does not expect the adoption of this interpretation to have a material impact on the Company's consolidated financial position or results of operations.

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3. 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. The Company has authorized the issuance of up to 2,700,000 shares under the 2003 Plan.

Prior to January 1, 2006, the Company accounted for the Plans under the recognition and measurement provisions of Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees," as permitted by SFAS No. 123. The Company also previously adopted the disclosure provisions under SFAS No. 123 and SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure." The Company recorded compensation expense of approximately $0.3 million pre-tax ($0.2 million after tax) and $0.9 million pre-tax ($0.6 million after tax), respectively, during the three and six months ended June 30, 2005 related to its performance units. No stock-based employee compensation expense related to stock options was recognized for the three and six months ended June 30, 2005 as all options granted under those plans had an exercise price equal to the market value of the Company's common stock on the grant date. Effective January 1, 2006, the Company adopted SFAS No. 123(R) using the modified prospective transition method. Under that transition method, compensation cost recognized in the first quarter of 2006 included: (i) compensation cost for all share-based payments granted prior to, but not yet vested as of January 1, 2006, based on the fair value calculated in accordance with the provisions of SFAS No. 123(R); and (ii) compensation cost for all share-based payments granted subsequent to January 1, 2006, based on the fair value calculated in accordance with the provisions of SFAS No. 123(R). Results for prior periods were not restated.

As a result of adopting SFAS No. 123(R) on January 1, 2006, the Company recorded compensation expense of approximately $1.8 million pre-tax ($1.1 million after tax, or $0.01 per basic and diluted share) during the three months ended March 31, 2006 related to the Company's share-based payments. Also, as a result of adopting SFAS No. 123(R), the Company recorded a cumulative effect adjustment of approximately $0.4 million pre-tax ($0.2 million after tax, or less than $0.01 per basic and diluted share) on January 1, 2006 for outstanding share-based compensation grants at December 31, 2005. The Company determined that the cumulative effect adjustment was immaterial for presentation purposes and is, therefore, included in Other Operation and Maintenance Expense in the Condensed Consolidated Statement of Income. The Company recorded compensation expense of approximately $2.4 million pre-tax ($1.4 million after tax, or $0.02 per basic and diluted share) during the three months ended June 30, 2006 related to the Company's share-based payments.

Prior to the adoption of SFAS No. 123(R), the Company presented all tax benefits of deductions resulting from the exercise of stock options or other share-based payments as operating cash flows in the Condensed Consolidated Statements of Cash Flows. SFAS 123(R) requires cash flows resulting in tax benefits from tax deductions in excess of the compensation cost recognized for share-based payments (excess tax benefits) to be classified as financing cash flows. The Company recorded an excess tax benefit related to the Company's share-based payments of approximately $1.1 million during the three and six months ended June 30, 2006. However, this amount will be presented as a financing cash inflow and realized when the Company's 2005 income tax return is completed later in 2006 and a deduction is taken.

Performance Units

Under the Plans, the Company issues performance units which represent the value of one share of the Company's common stock. The performance units provide for accelerated vesting if there is a change in control (as defined in the Plans). Each performance unit is subject to forfeiture if the recipient ceases to render substantial services to the Company or a subsidiary for any reason other than death, disability or retirement. In the event of death, disability or retirement, a participant will receive a prorated payment based on such participant's number of full months of service during the three-year award cycle, further adjusted based on the achievement of the performance goals during the award cycle. The following table is a summary of the terms of the Company's outstanding performance units.

Condition	Settlement	Vesting Period	SFAS No. 123(R) Classification
Total Shareholder Return	2/3 – Stock (A)	3-year cliff	Equity
	1/3 – Cash	3-year cliff	Liability
Earnings Per Share	2/3 – Stock (A)	3-year cliff	Equity
	1/3 – Cash	3-year cliff	Liability

(A) All of the Company's 2006 performance units are settled in stock.

The performance units granted based on total shareholder return ("TSR") are contingently awarded and will be payable in cash or shares of the Company's common stock (other than performance units awarded in 2006, which will be payable only in shares of common stock) subject to the condition that the number of performance units, if any, earned by the employees upon the expiration of a three-year award cycle is dependent on the Company's TSR ranking relative to a peer group of companies. The performance units granted based on earnings per share ("EPS") are contingently awarded and will be payable in cash or shares of the Company's common stock (other than performance units awarded in 2006, which will be payable only in shares of common stock) based on the Company's EPS growth over a three-year award cycle compared to a target set at the time of the grant by the Compensation Committee of the Company's Board of Directors. If there is no payout for the performance units at the end of the three-year award cycle, the performance units are cancelled.

Performance Units – Total Shareholder Return

As a result of adopting SFAS No. 123(R) on January 1, 2006, the Company recorded compensation expense of approximately $1.2 million pre-tax ($0.7 million after tax) during the three months ended March 31, 2006 related to the performance units based on TSR. The Company recorded compensation expense of approximately $1.9 million pre-tax ($1.1 million after tax) during the three months ended June 30, 2006 related to the performance units based on TSR. The Company recorded compensation expense of approximately $0.3 million pre-tax ($0.2 million after tax) and $0.9 million pre-tax ($0.6 million after tax), respectively, during the three and six months ended June 30, 2005 related to performance units based on TSR. The fair value of the performance units based on TSR was estimated on the grant date using a lattice-based valuation model that factors in information, including the expected dividend yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance units. Compensation expense for the performance units settled in stock is a fixed amount determined at the grant date fair value and is recognized over the three-year award cycle regardless of whether performance units are awarded at the end of the award cycle. Compensation expense for the performance units settled in cash is based on the change in the fair value of the performance units for each reporting period. This liability for the performance units will be remeasured at each reporting date until the date of settlement. Dividends are not accrued or paid during the performance period and, therefore, are not included in the fair value calculation. Expected price volatility is based on the historical volatility of the Company's common stock for the past three years and was simulated using the Geometric Brownian Motion process. The risk-free interest rate for the performance unit grants is based on the three-year U.S. Treasury yield curve in effect at the time of the grant. The expected life of the units is based on the non-vested period since inception of the three-year award cycle. There are no post-vesting restrictions related to the Company's performance units based on TSR. The fair value of the performance units based on TSR was calculated based on the following assumptions at the grant date.

	2006	2005	2004
Expected dividend yield	4.9%	5.3%	6.5%
Expected price volatility	16.8%	22.3%	23.0%
Risk-free interest rate	4.66%	3.28%	2.47%
Expected life of units (in years)	2.85	2.85	2.94
Fair value of units granted	$ 22.93	$ 21.56	$ 20.10

The fair value of the performance units based on TSR which are settled in cash was remeasured at June 30, 2006 based on the following assumptions.

	2005	2004
Expected dividend yield	4.7%	4.7%
Expected price volatility	15.8%	15.8%
Risk-free interest rate	5.28%	5.31%
Expected life of units (in years)	1.5	0.5
Fair value of units at 6/30/06	$ 47.25	$ 52.58

A summary of the activity for the Company's performance units based on TSR at June 30, 2006 and changes during the three and six months ended June 30, 2006 are summarized in the following table. Following the end of a three-year performance period, payout of the performance units based on TSR is determined by the Company's TSR for such period compared to a peer group and payout requires the approval of the Compensation Committee of the Company's Board of Directors. Payouts, if any, are made in stock and cash (other than payouts of performance units awarded in 2006, which will be made only in common stock) and are considered made when the payout is approved by the Compensation Committee.

(dollars in millions)	Number of Units	Stock Conversion Ratio (A)	Aggregate Intrinsic Value
Units Outstanding at 12/31/05	385,528	1 : 1	
Granted (B)	179,892	1 : 1	
Converted	(111,235)	1 : 1	$ 4.3
Forfeited	(3,688)	1 : 1	
Units Outstanding at 3/31/06	450,497	1 : 1	$ 19.1
Forfeited	(3,055)	1 : 1	
Units Outstanding at 6/30/06	447,442	1 : 1	$ 23.6

(A) One performance unit = one share of the Company's common stock.
(B) Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.

A summary of the activity for the Company's non-vested performance units based on TSR at June 30, 2006 and changes during the three and six months ended June 30, 2006 are summarized in the following table:

	Number of Units	Weighted-Average Grant Date Fair Value
Units Non-Vested at 12/31/05	274,293	$ 20.84
Granted (A)	179,892	$ 22.93
Forfeited	(3,688)	$ 21.83
Units Non-Vested at 3/31/06	450,497	$ 21.67
Forfeited	(3,055)	$ 21.83
Units Non-Vested at 6/30/06 (B)	447,442	$ 21.67

(A) Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.
(B) Of the 447,442 performance units not vested at June 30, 2006, 399,017 performance units are assumed to vest at the end of the vesting period.

At June 30, 2006, there was approximately $5.3 million in unrecognized compensation cost related to non-vested performance units based on TSR which is expected to be recognized over a weighted-average period of 1.90 years.

Performance Units – Earnings Per Share

As a result of adopting SFAS No. 123(R) on January 1, 2006, the Company recorded compensation expense of approximately $0.6 million pre-tax ($0.4 million after tax) during the three months ended March 31, 2006 related to the performance units based on EPS. The Company recorded compensation expense of approximately $0.5 million pre-tax ($0.3 million after tax) during the three months ended June 30, 2006 related to the performance units based on EPS. No compensation expense was recorded during the three and six months ended June 30, 2005 related to performance units based on EPS as the probable performance was below the threshold for payout. The fair value of the performance units based on EPS is based on grant date fair value which is equivalent to the price of one share of the Company's common stock on the date of grant. The fair value of performance units based on EPS varies as the number of performance units that will vest is based on the grant date fair value of the units and the probable outcome of the performance condition. The Company reassesses at each reporting date whether achievement of the performance condition is probable and accrues compensation expense if and when achievement of the performance condition is probable. As a result, the compensation expense recognized for these performance units can vary from period to period. There are no post-vesting restrictions related to the Company's performance units based on EPS. The grant date fair value of the 2005 and 2006 performance units was $23.78 and $28.00, respectively.

A summary of the activity for the Company's performance units based on EPS at June 30, 2006 and changes during the three and six months ended June 30, 2006 are summarized in the following table. Following the end of a three-year performance period, payout of the performance units based on EPS growth is determined by the Company's growth in EPS for such period compared to a target set at the beginning of the three-year period by the Compensation Committee of the Company's Board of Directors and payout requires the approval of the Compensation Committee. Payouts, if any, are made in stock and cash (other than payouts of performance units awarded in 2006, which will be made only in common stock) and are considered made when approved by the Compensation Committee.

(dollars in millions)	Number of Units	Stock Conversion Ratio (A)	Aggregate Intrinsic Value
Units Outstanding at 12/31/05	46,539	1:1	
Granted (B)	59,964	1:1	
Forfeited	(1,001)	1:1	
Units Outstanding at 3/31/06	105,502	1:1	$ 6.1
Forfeited	(758)	1:1	
Units Outstanding at 6/30/06	104,744	1:1	$ 7.3

(A) One performance unit = one share of the Company's common stock.
(B) Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.

A summary of the activity for the Company's non-vested performance units based on EPS at June 30, 2006 and changes during the three and six months ended June 30, 2006 are summarized in the following table:

	Number of Units	Weighted-Average Grant Date Fair Value
Units Non-Vested at 12/31/05	46,539	$ 23.78
Granted (A)	59,964	$ 28.00
Forfeited	(1,001)	$ 25.81
Units Non-Vested at 3/31/06	105,502	$ 26.16
Forfeited	(758)	$ 26.44
Units Non-Vested at 6/30/06 (B)	104,744	$ 26.16

(A) Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.
(B) Of the 104,744 performance units not vested at June 30, 2006, 89,210 performance units are assumed to vest at the end of the vesting period.

At June 30, 2006, there was approximately $3.4 million in unrecognized compensation cost related to non-vested performance units based on EPS which is expected to be recognized over a weighted-average period of 2.17 years.

Stock Options

As a result of adopting SFAS No. 123(R) on January 1, 2006, the Company recorded compensation expense of less than $0.1 million during the three months ended March 31, 2006 related to stock options and less than $0.1 million during the three months ended June 30, 2006 related to the stock options. During the first six months of 2006 and during 2005, no stock options were granted under the 2003 Plan. Previous option awards were granted with an exercise price equal to the market value of the Company's common stock on the grant date which resulted in no stock-based employee compensation expense being recognized. The Company accounts for stock option grants as separate grants. The options granted under the Plans vest in one-third annual installments beginning one year from the date of grant and have a contractual life of 10 years. Each option is subject to forfeiture if the recipient ceases to render substantial services to the Company or a subsidiary for any reason other than death, disability or retirement. Dividends are not paid or accrued on unexercised options. The options provide for accelerated vesting if there is a change in control (as defined in the Plans). The fair value of each option grant under the Plans is estimated on the grant date using the Black-Scholes option pricing model and was $2.05 at the grant date for the stock options that are not fully vested at December 31, 2005.

A summary of the activity for the Company's options at June 30, 2006 and changes during the three and six months ended June 30, 2006 are summarized in the following table:

(dollars in millions)	Number of Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value	Weighted-Average Remaining Contractual Term
Options Outstanding at 12/31/05	2,139,376	$ 22.20		
Exercised	(99,258)	$ 19.03	$ 0.9	
Expired	(10,100)	$ 28.75		
Forfeited	(900)	$ 23.58		
Options Outstanding at 3/31/06	2,029,118	$ 22.32	$ 13.6	5.84 years
Exercised	(199,217)	$ 21.24	$ 2.0	

Expired	(5,100)	$ 22.28		
Forfeited	(567)	$ 23.58		
Options Outstanding at 6/30/06	1,824,234	$ 22.43	$ 23.0	5.25 years
Options Fully Vested and Exercisable at 6/30/06	1,728,451	$ 22.37	$ 21.9	5.14 years

A summary of the activity for the Company's non-vested options at June 30, 2006 and changes during the three and six months ended June 30, 2006 are summarized in the following table:

	Number of Options	Weighted-Average Grant Date Fair Value
Options Non-Vested at 12/31/05	404,398	$ 1.95
Vested	(306,848)	$ 1.91
Forfeited	(900)	$ 2.05
Options Non-Vested at 3/31/06	96,650	$ 2.05
Vested	(300)	$ 2.05
Forfeited	(567)	$ 2.05
Options Non-Vested at 6/30/06 (A)	95,783	$ 2.05

(A) Of the 95,783 stock options not vested at June 30, 2006, 92,564 stock options are assumed to vest at the end of the vesting period.

At June 30, 2006, there was less than $0.1 million in unrecognized compensation cost related to non-vested options which is expected to be recognized over a weighted-average period of 0.50 years.

The Company issues new shares to satisfy stock option exercises. The Company received approximately $4.2 million and $6.1 million, respectively, during the three and six months ended June 30, 2006 related to exercised stock options. The Company recorded an excess tax benefit of approximately $1.1 million related to the Company's exercised stock options during the three and six months ended June 30, 2006. However, this amount will be presented as a financing cash inflow and realized when the Company's 2005 income tax return is completed later in 2006 and a deduction is taken.

4. Asset Retirement Obligation

In accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations" issued in June 2001, for periods subsequent to the initial measurement of an asset retirement obligations ("ARO"), an entity shall recognize period-to-period changes in the liability for an ARO resulting from: (i) the passage of time; and (ii) revisions to either the timing or the amount of the original estimate of undiscounted cash flows. During the second quarter of 2006, the Company reviewed its initial ARO valuations and determined that there were changes in the liability of the ARO resulting from revisions to the amount of the original estimate of undiscounted cash flows. As a result, an ARO of approximately $1.0 million was recognized as an increase in the carrying amount of the liability for an ARO and an increase in the related asset retirement cost capitalized as part of the carrying amount of the related long-lived asset with no effect on net income.

5. Loss on Retirement of Fixed Assets

OG&E had a power supply contract with a large industrial customer which expired June 1, 2006. In conjunction with the expiration of this contract, OG&E evaluated other options to utilize the turbines dedicated to that customer, which resulted in the decision to retire these assets as of June 30, 2006. The carrying amount of these assets at June 30, 2006 is

approximately $6.8 million which has been recorded as a pre-tax loss during the second quarter of 2006. This loss is included in Other Expense in the Condensed Consolidated Statement of Income.

6. 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 consolidated balance sheet.

In the Company's Condensed Consolidated Balance Sheets at June 30, 2006 and December 31, 2005, the fair value of transactions with the same counterparty is presented on a gross basis, consistent with past practice.

However, OGE Energy Resources, Inc. ("OERI") has energy trading contracts with set off provisions with various counterparties. If these transactions with the same counterparty were presented on a net basis in the Condensed Consolidated Balance Sheets, Price Risk Management assets and liabilities would be approximately $39.0 million and $31.0 million at June 30, 2006, respectively, and would be approximately $98.0 million and $92.8 million at December 31, 2005, respectively.

7. Accumulated Other Comprehensive Loss

The components of total comprehensive income for the three and six months ended June 30, 2006 and 2005, respectively, are as follows:

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	**2006**	2005	**2006**	2005
Net income	**$ 93.7**	$ 38.5	**$ 118.6**	$ 43.8
Other comprehensive income (loss), net of tax:				
Deferred hedging gains (losses), net of tax	**(4.1)**	1.7	**(4.6)**	(0.1)
Amortization of cash flow hedge, net of tax	**0.1**	---	**0.1**	0.1
Total comprehensive income	**$ 89.7**	$ 40.2	**$ 114.1**	$ 43.8

The components of accumulated other comprehensive loss at June 30, 2006 and December 31, 2005 are as follows:

(In millions)	**June 30, 2006**	December 31, 2005
Minimum pension liability adjustment, net of tax	**$ (91.1)**	$ (91.1)
Deferred hedging gains, net of tax	**(1.5)**	3.1
Settlement and amortization of cash flow hedge, net of tax	**(2.1)**	(2.2)
Total accumulated other comprehensive loss	**$ (94.7)**	$ (90.2)

Accumulated other comprehensive loss at both June 30, 2006 and December 31, 2005 included an after tax loss of approximately $91.1 million ($148.6 million pre-tax) related to a minimum pension liability adjustment based on a review of the funded status of the Company's pension plan by the Company's actuarial consultants as of December 31, 2005. Any increases or decreases in the minimum pension liability will be reflected in Other Comprehensive Income or Loss in the fourth quarter. See "Management's Discussion and Analysis of Financial Condition and Results of Operations - Pension and Postretirement Benefit Plans" for a discussion of a possible settlement charge to be recorded later in 2006.

8. Enogex – Discontinued Operations

In April 2005, Enogex Compression Company, LLC ("Enogex Compression") received an unsolicited offer to buy its interest in Enerven Compression Services, LLC ("Enerven"), a joint venture focused on the rental of natural gas compression assets. After evaluating this offer, Enogex Compression sold its interest in Enerven for approximately $7.3 million in August 2005. Enogex Compression recognized an after tax gain of approximately $1.8 million related to the sale of this business.

Enogex regularly evaluates the long term stability, profitability and core competency of each of its businesses within the regulatory and market framework in which each business operates. Based on these evaluations, in September 2005, Enogex announced that it had entered into an agreement to sell its interest in Enogex Arkansas Pipeline Corporation ("EAPC"), which held the NOARK Pipeline System Limited Partnership interest. This sale was completed on October 31, 2005. The Company received approximately $177.4 million in cash proceeds and recognized an after tax gain of approximately $36.7 million from the sale of this business in the fourth quarter of 2005. Enogex used approximately $31.9 million of the proceeds to repay principal and accrued interest on long-term debt and approximately $46.7 million to pay taxes associated with EAPC. The balance of the proceeds of approximately $98.8 million, following temporary use to fund current cash needs, is expected to be used to invest, over time, in strategic assets.

In March 2006, Enogex announced that its wholly-owned subsidiary, Gathering, had entered into an agreement to sell certain gas gathering assets in the Kinta, Oklahoma, area. The Gathering assets included in the transaction were approximately 568 miles of gas gathering pipeline and 22 compressor units with current volumes of approximately 145 million cubic feet per day, all in eastern Oklahoma. The sale price was approximately $93 million. This transaction closed on May 1, 2006 and Enogex recorded an after tax gain of approximately $34.7 million during the second quarter of 2006. The proceeds from the sale, following temporary use to fund current cash needs, are expected to be used to invest, over time, in strategic assets.

The Condensed Consolidated Financial Statements of the Company have been reclassified to reflect Enogex Compression's sale of its Enerven interest, Enogex's sale of its EAPC interest and Gathering's sale of certain gas gathering assets in Kinta, Oklahoma, all of which were part of the Natural Gas Pipeline segment, as discontinued operations. Accordingly, revenues, costs and expenses and cash flows of Enerven, EAPC and the Gathering assets that were sold have been excluded from the respective captions in the Condensed Consolidated

Financial Statements and have been separately reported as discontinued operations in the applicable financial statement captions. Enogex Compression's sale of its Enerven interest and Enogex's sale of its EAPC interest were completed during 2005 and, therefore, there are no results of operations for these transactions during the three or six months ended June 30, 2006. Summarized financial information for the discontinued operations as of June 30 is as follows:

CONDENSED CONSOLIDATED STATEMENTS OF INCOME DATA

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	**2006**	2005	**2006**	2005
Operating revenues from discontinued operations	**$ 2.8**	$ 26.9	**$ 9.4**	$ 54.2
Income from discontinued operations before taxes	**$ 58.8**	$ 4.4	**$ 60.1**	$ 10.2

CONDENSED CONSOLIDATED BALANCE SHEET DATA

(In millions)	**June 30, 2006**	December 31, 2005
Plant in service of discontinued operations	$ ---	$ 60.6
Less accumulated depreciation	---	25.7
Net property, plant and equipment of discontinued operations	$ ---	$ 34.9
Total deferred charges and other assets of discontinued operations	$ ---	$ 2.4

9. Supplemental Cash Flow Information

The following table discloses information about investing and financing activities that affect recognized assets and liabilities but which do not result in cash receipts or payments.

	Six Months Ended June 30,	
(In millions)	**2006**	2005
NON-CASH INVESTING AND FINANCING ACTIVITIES		
Change in fair value of long-term debt due to interest rate swaps	$ ---	$ (4.0)

10. Income Taxes

The Company files consolidated income tax returns. Income taxes are allocated to each affiliate based on its separate taxable income or loss. Federal investment tax credits 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 June 30,		Six Months Ended June 30,	
	2006	2005	**2006**	2005
Statutory federal tax rate	**35.0%**	35.0%	**35.0%**	35.0%
State income taxes, net of federal income tax benefit	**3.7**	3.7	**3.7**	3.7
Tax credits, net	**(2.4)**	(3.4)	**(2.7)**	(5.6)
Other	**0.1**	(0.1)	**(0.4)**	(0.1)
Effective income tax rate as reported	**36.4%**	35.2%	**35.6%**	33.0%

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.

In July 2003, Enogex Products Corporation ("Products") filed a refund claim related to sales and use tax for years 1999 through 2002 with the Oklahoma Tax Commission ("OTC"). In May 2006, Products received a refund of approximately $2.0 million from the OTC related to this claim that is included as a reduction in Other Operation and Maintenance Expense in the Condensed Consolidated Statement of Income.

In connection with the filing in the third quarter of 2003 of the Company's consolidated income tax returns for 2002, OG&E elected to change its tax method of accounting related to the capitalization of costs for self-constructed assets to another method prescribed in the Treasury regulations. The accounting method change was for income tax purposes only. For financial accounting purposes, the only change was recognition of the impact of the cash flow generated by accelerating income tax deductions. This was reflected in the financial statements as a switch from current income taxes payable to deferred income taxes payable. This tax accounting method change resulted in a one-time catch-up deduction for costs previously capitalized under the prior method, resulting in a consolidated tax net operating loss for 2002. This tax net operating loss eliminated the Company's current federal and state income tax liability for 2002 and 2003 and all estimated payments made for 2002 were refunded. The Company received federal and state income tax refunds of approximately $50.8 million during 2003 related to this tax accounting method change. During 2005, new guidelines were issued by the Internal Revenue Service ("IRS") related to the change in the method of accounting used to capitalize costs for self-construction discussed above. The Company's current IRS examination process, which was completed in the second quarter of 2006, identified this change in method of accounting as an issue under examination. As a result of their examination, the IRS determined that OG&E should change its tax method of accounting for the capitalization of costs for self-constructed assets to another method prescribed in the Treasury regulations. The Company filed a formal protest with the IRS on July 21, 2006 and requested a hearing with the IRS to review the IRS's determination that the tax accounting method OG&E elected in 2002 was not appropriate. The impact of this matter on future earnings and cash flows is uncertain but could be material. The Company cannot predict either the final outcome or the timing of the resolution of this matter. During 2005 and the first six months of 2006, OG&E recorded approximately $3.1 million in additional interest expense related to income taxes as a result of a potential adjustment. This amount is included in Interest on Short-Term Debt and Other Interest Charges in the Consolidated Statements of Income. OG&E expects to accrue approximately $0.3 million monthly going forward for additional interest expense related to this matter.

11. Common Stock

For the three and six months ended June 30, 2006, respectively, there were 199,217 shares and 298,475 shares, respectively, of new common stock issued pursuant to the Company's Stock Incentive Plan, related to exercised stock options and payouts of earned performance units awarded in January 2003.

12. Earnings Per Share

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

	Three Months Ended June 30,		**Six Months Ended June 30,**	
(In millions)	**2006**	2005	**2006**	2005
Average Common Shares Outstanding				
Basic average common shares outstanding	**90.9**	90.2	**90.8**	90.1
Effect of dilutive securities:				
Employee stock options and unvested stock grants	**0.3**	0.3	**0.3**	0.2
Contingently issuable shares (performance units)	**0.8**	0.3	**0.8**	0.3
Diluted average common shares outstanding	**92.0**	90.8	**91.9**	90.6

Approximately 0.3 million shares for each period related to outstanding employee stock options were not included in the calculation of diluted earnings per average common share because the effect of including those shares is anti-dilutive as the exercise price of the stock options exceeded the average common stock market price during the respective period.

13. Long-Term Debt

At June 30, 2006, the Company is in compliance with all of its debt agreements.

Long-Term Debt with Optional Redemption Provisions

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**
3.150% - 3.898%	Garfield Industrial Authority, January 1, 2025	**$ 47.0**
3.205% - 3.395%	Muskogee Industrial Authority, January 1, 2025	**32.4**
3.063% - 3.918%	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 has sufficient liquidity to meet these obligations.

14. Short-Term Debt

The short-term debt balance was approximately $58.2 million and $30.0 million at June 30, 2006 and December 31, 2005, respectively, an increase of approximately $28.2 million or 94.0 percent. In accordance with SFAS No. 6, "Classification of Short-Term Obligations Expected to Be Refinanced, an Amendment of Accounting Research Bulletin No. 43, Chapter 3A," $220.0 million in commercial paper and bank borrowings was used to temporarily fund $220 million of long-term debt of OG&E that had matured or been called for redemption in the fourth quarter of 2005. This commercial paper was classified as long-term debt at December 31, 2005 as OG&E planned to refinance this amount. Subsequently, OG&E issued $220 million of long-term debt in January 2006 and repaid the outstanding commercial paper and bank borrowings. The following table shows the Company's revolving credit agreements and available cash at June 30, 2006.

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

Entity	Amount Available	Amount Outstanding	Weighted-Average Interest Rate	Maturity
OGE Energy Corp. (A)	$ 600.0	$ ---	N/A	September 30, 2010 (C)
OG&E (B)	150.0	---	N/A	September 30, 2010 (C)
	750.0	---	N/A	
Cash	---	N/A	N/A	N/A
Total	$ 750.0	$ ---	N/A	

(A) This bank facility is available to back up a maximum of $300.0 million of the Company's commercial paper borrowings and to provide an additional $300.0 million in revolving credit borrowings. This bank facility can also be used as a letter of credit facility. At June 30, 2006, there was approximately $58.2 million in outstanding commercial paper borrowings.
(B) This bank facility is available to back up a maximum of $100.0 million of OG&E's commercial paper borrowings and to provide an additional $50.0 million in revolving credit borrowings. At June 30, 2006, OG&E had approximately $0.2 million supporting a letter of credit and no outstanding commercial paper borrowings
(C) During 2005, the Company and OG&E entered into revolving credit agreements totaling $750 million, one for the Company in an amount up to $600 million and one for OG&E in an amount up to $150 million. Each of the credit facilities has a five-year term with two options to extend the term for one year.

The Company's and OG&E's ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruptions. Pricing grids associated with the back-up lines of credit could cause annual fees and borrowing rates to increase if an adverse ratings impact occurs. The impact of any future downgrades would result in an increase in the cost of short-term borrowings but would not result in any defaults or accelerations as a result of the rating changes.

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 $400 million in short-term borrowings at any one time for a two-year period beginning January 1, 2005 and ending December 31, 2006.

15. Retirement Plans and Postretirement Benefit Plans

The details of net periodic benefit cost of the pension plan (including 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 and Restoration of Retirement Income Plan			
	Three Months Ended June 30,		**Six Months Ended June 30,**	
(In millions)	**2006**	2005	**2006**	2005
Service cost	**$ 5.1**	$ 4.7	**$ 10.2**	$ 9.5
Interest cost	**7.6**	7.6	**15.4**	15.2
Return on plan assets	**(9.5)**	(8.6)	**(19.1)**	(17.1)
Amortization of net loss	**4.1**	3.8	**8.3**	7.4
Amortization of unrecognized prior service cost	**1.4**	1.5	**2.9**	3.1
Net periodic benefit cost	**$ 8.7**	$ 9.0	**$ 17.7**	$ 18.1

	Postretirement Benefit Plans			
	Three Months Ended June 30,		**Six Months Ended June 30,**	
(In millions)	**2006**	2005	**2006**	2005
Service cost	**$ 0.9**	$ 0.8	**$ 1.8**	$ 1.6
Interest cost	**3.0**	2.6	**6.0**	5.2
Return on plan assets	**(1.4)**	(1.4)	**(2.8)**	(2.8)
Amortization of transition obligation	**0.7**	0.7	**1.4**	1.4
Amortization of net loss	**2.1**	1.3	**4.3**	2.6
Amortization of unrecognized prior service cost	**0.5**	0.5	**1.0**	1.0
Net periodic benefit cost	**$ 5.8**	$ 4.5	**$ 11.7**	$ 9.0

Pension Plan Funding

The Company previously disclosed in its Form 10-K for the year ended December 31, 2005 that it may contribute up to $90 million to its pension plan during 2006. In the second quarter of 2006, the Company contributed approximately $60.0 million to the pension plan and currently expects to contribute an additional $30.0 million to the pension plan during the remainder of 2006. Any expected contributions to the pension plan during 2006 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.

16. Report of Business Segments

The Company's Electric Utility operations are conducted through OG&E, a regulated utility engaged in the generation, transmission, distribution and sale of electric energy. The Company's Natural Gas Pipeline operations are conducted through Enogex. Enogex is engaged in the transportation and storage of natural gas, the gathering and processing of natural gas and the marketing of natural gas. Other Operations for the three and six months ended June 30, 2006 and for the three and six months ended June 30, 2005 primarily includes unallocated corporate expenses, interest expense on commercial paper and interest expense on long-term debt. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. The following tables summarize the results of the Company's business segments for the three and six months ended June 30, 2006 and 2005.

Three Months Ended June 30, 2006	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	**$ 444.7**	**$ 517.6**	**$ ---**	**$ (28.0)**	**$ 934.3**
Cost of goods sold	**229.6**	**448.0**	**---**	**(27.4)**	**650.2**
Gross margin on revenues	**215.1**	**69.6**	**---**	**(0.6)**	**284.1**
Other operation and maintenance	**80.0**	**25.4**	**(2.4)**	**---**	**103.0**
Depreciation	**33.2**	**10.4**	**1.9**	**---**	**45.5**
Taxes other than income	**13.1**	**4.2**	**0.6**	**---**	**17.9**
Operating income (loss)	**88.8**	**29.6**	**(0.1)**	**(0.6)**	**117.7**
Other income	**0.6**	**0.2**	**0.9**	**---**	**1.7**
Other expense	**8.4**	**0.1**	**1.1**	**---**	**9.6**
Interest income	**0.4**	**3.3**	**1.0**	**(3.1)**	**1.6**
Interest expense	**11.5**	**7.9**	**3.9**	**(3.1)**	**20.2**

Income tax expense (benefit)		**25.9**		**9.6**		**(2.0)**		**(0.2)**		**33.3**
Income (loss) from continuing operations	**$**	**44.0**	**$**	**15.5**	**$**	**(1.2)**	**$**	**(0.4)**	**$**	**57.9**
Income from discontinued operations	**$**	**---**	**$**	**35.8**	**$**	**---**	**$**	**---**	**$**	**35.8**
Net income (loss)	**$**	**44.0**	**$**	**51.3**	**$**	**(1.2)**	**$**	**(0.4)**	**$**	**93.7**
Total assets	**$**	**3,387.4**	**$**	**1,394.2**	**$**	**1,946.7**	**$**	**(2,006.1)**	**$**	**4,722.2**

(A) Natural Gas Pipeline's operations consist of three related businesses: Transportation and Storage, Gathering and Processing and Marketing. The following table provides supplemental Natural Gas Pipeline information.

Three Months Ended June 30, 2006		Transportation and Storage		Gathering and Processing		Marketing		Eliminations		Total
(In millions)										
Operating revenues	**$**	**63.1**	**$**	**166.6**	**$**	**420.0**	**$**	**(132.1)**	**$**	**517.6**
Operating income (loss)	**$**	**11.2**	**$**	**21.0**	**$**	**(2.6)**	**$**	**---**	**$**	**29.6**

Three Months Ended June 30, 2005		Electric Utility		Natural Gas Pipeline (A)		Other Operations		Intersegment		Total
(In millions)										
Operating revenues	$	394.1	$	968.9	$	---	$	(32.8)	$	1,330.2
Cost of goods sold		215.9		911.0		---		(32.6)		1,094.3
Gross margin on revenues		178.2		57.9		---		(0.2)		235.9
Other operation and maintenance		79.7		22.8		(2.7)		---		99.8
Depreciation		31.4		10.0		2.1		---		43.5
Taxes other than income		12.1		4.0		0.7		---		16.8
Operating income (loss)		55.0		21.1		(0.1)		(0.2)		75.8
Other income		0.3		0.5		0.2		---		1.0
Other expense		0.3		0.1		0.6		---		1.0
Interest income		---		0.5		0.2		(0.6)		0.1
Interest expense		9.7		8.1		3.4		(0.6)		20.6
Income tax expense (benefit)		15.6		5.3		(1.4)		---		19.5
Income (loss) from continuing operations	$	29.7	$	8.6	$	(2.3)	$	(0.2)	$	35.8
Income from discontinued operations	$	---	$	2.7	$	---	$	---	$	2.7
Net income (loss)	$	29.7	$	11.3	$	(2.3)	$	(0.2)	$	38.5
Total assets	$	3,144.0	$	1,647.8	$	1,794.1	$	(1,772.6)	$	4,813.3

(A) Natural Gas Pipeline's operations consist of three related businesses: Transportation and Storage, Gathering and Processing and Marketing. The following table provides supplemental Natural Gas Pipeline information.

Three Months Ended June 30, 2005		Transportation and Storage		Gathering and Processing		Marketing		Eliminations		Total
(In millions)										
Operating revenues	$	61.0	$	152.6	$	887.0	$	(131.7)	$	968.9
Operating income (loss)	$	9.2	$	14.3	$	(2.4)	$	---	$	21.1

Six Months Ended	Electric	Natural Gas	Other

June 30, 2006	Utility	Pipeline (A)	Operations	Intersegment	Total
(In millions)					
Operating revenues	$ 818.7	$ 1,280.8	$ ---	$ (55.4)	$ 2,044.1
Cost of goods sold	467.3	1,126.0	---	(54.6)	1,538.7
Gross margin on revenues	351.4	154.8	---	(0.8)	505.4
Other operation and maintenance	159.7	54.0	(5.2)	---	208.5
Depreciation	66.3	20.6	3.5	---	90.4
Taxes other than income	26.8	8.5	1.7	---	37.0
Operating income	98.6	71.7	---	(0.8)	169.5
Other income	0.8	6.2	1.4	---	8.4
Other expense	9.5	0.1	1.2	---	10.8
Interest income	1.4	5.8	2.4	(6.5)	3.1
Interest expense	25.2	16.0	8.2	(6.5)	42.9
Income tax expense (benefit)	23.2	25.9	(3.5)	(0.3)	45.3
Income (loss) from continuing operations	$ 42.9	$ 41.7	$ (2.1)	$ (0.5)	$ 82.0
Income from discontinued operations	$ ---	$ 36.6	$ ---	$ ---	$ 36.6
Net income (loss)	$ 42.9	$ 78.3	$ (2.1)	$ (0.5)	$ 118.6
Total assets	$ 3,387.4	$ 1,394.2	$ 1,946.7	$ (2,006.1)	$ 4,722.2

(A) Natural Gas Pipeline's operations consist of three related businesses: Transportation and Storage, Gathering and Processing and Marketing. The following table provides supplemental Natural Gas Pipeline information.

Six Months Ended June 30, 2006	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	$ 127.7	$ 326.5	$ 1,097.1	$ (270.5)	$ 1,280.8
Operating income	$ 33.3	$ 37.4	$ 1.0	$ ---	$ 71.7

Six Months Ended June 30, 2005	Electric Utility (A)	Natural Gas Pipeline (B)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	$ 695.1	$ 1,954.1	$ ---	$ (53.7)	$ 2,595.5
Cost of goods sold	390.9	1,844.6	---	(54.5)	2,181.0
Gross margin on revenues	304.2	109.5	---	0.8	414.5
Other operation and maintenance	157.1	45.3	(5.8)	---	196.6
Depreciation	64.5	20.0	3.9	---	88.4
Taxes other than income	24.8	8.3	1.9	---	35.0
Operating income	57.8	35.9	---	0.8	94.5
Other income	1.0	0.5	1.1	---	2.6
Other expense	0.8	0.1	1.7	---	2.6
Interest income	1.6	1.1	0.5	(1.1)	2.1
Interest expense	19.4	16.0	6.3	(1.1)	40.6
Income tax expense (benefit)	12.2	8.3	(2.4)	0.4	18.5
Income (loss) from continuing operations	$ 28.0	$ 13.1	$ (4.0)	$ 0.4	$ 37.5
Income from discontinued operations	$ ---	$ 6.3	$ ---	$ ---	$ 6.3
Net income (loss)	$ 28.0	$ 19.4	$ (4.0)	$ 0.4	$ 43.8
Total assets	$ 3,144.0	$ 1,647.8	$ 1,794.1	$ (1,772.6)	$ 4,813.3

(A) In January 2005, a cogeneration credit rider was implemented at OG&E as part of the Oklahoma retail customer electric rates in order to return purchase power capacity payment reductions and any change in operating and maintenance expense related to cogeneration previously included in base rates to OG&E's customers. This rider resulted in the seasonal over or under collection of revenues as the rider is based on an equal monthly amount of kilowatt-hour ("kwh") usage as compared to actual kwh usage. Due to the seasonal rates of OG&E's electric sales, this resulted in a temporary over collection of operating revenues in excess of the reduction in operating and maintenance expense for the first quarter of 2005 of approximately $3.4 million. In August 2005, the Company determined that OG&E's net income should not be affected by over or under collections on a temporary or permanent basis, and accordingly, any difference at that time was deferred as a regulatory asset to better reflect the purchase power capacity payment reductions and any change in operating and maintenance expense related to cogeneration. Subsequent to August 2005, any over or under collections related to the cogeneration credit rider are reflected as a regulatory asset or liability.

(B) Natural Gas Pipeline's operations consist of three related businesses: Transportation and Storage, Gathering and Processing and Marketing. The following table provides supplemental Natural Gas Pipeline information.

Six Months Ended June 30, 2005	Transportation and Storage	Gathering and Processing	Marketing (C)	Eliminations	Total
(In millions)					
Operating revenues	$ 112.7	$ 296.1	$ 1,790.7	$ (245.4)	$ 1,954.1
Operating income (loss)	$ 18.3	$ 24.0	$ (6.4)	$ ---	$ 35.9

(C) In March 2005, Enogex corrected its procedure for accounting for park and loan transactions (natural gas storage transactions) during 2004 that resulted from an incorrect change in an accounting procedure implemented during 2004. The incorrect procedure affected the timing of recognition of revenue and income from park and loan transactions and resulted in a temporary overstatement of operating revenues without the associated expense until the transaction was completed and the expense recognized. As a result of this correction, Enogex recorded a pre-tax charge of approximately $7.7 million as a reduction in Operating Revenues in the Condensed Consolidated Statement of Income and a corresponding $7.7 million decrease in Current Price Risk Management Assets in the Condensed Consolidated Balance Sheet during the three months ended June 30, 2005.

17. Commitments and Contingencies

Except as set forth below and in Note 18, the circumstances set forth in Notes 14 and 15 to the Company's Consolidated Financial Statements included in the Company's Form 10-K for the year ended December 31, 2005 appropriately represent, in all material respects, the current status of any material commitments and contingent liabilities.

Capital Expenditures

As previously disclosed in the Company's Form 10-K for the year ended December 31, 2005, the Company's 2006, 2007 and 2008 capital expenditures were estimated at approximately: $307 million, $248 million and $250 million, respectively. The Company's current estimate for 2006 capital expenditures is approximately $528 million, which includes capital expenditures of up to $205 million associated with OG&E's wind power project. OG&E received approval for the wind power project by the OCC on April 28, 2006 and expects to fund the wind power project with a capital contribution from the holding company and the issuance of long-term debt in either the third or fourth quarter of 2006. The Company's current estimate for 2007 and 2008 capital expenditures is approximately $280 million in each year. These capital expenditures do not include capital expenditures related to the construction of a proposed power plant as discussed in Note 18.

Natural Gas Storage Facility Agreement with Central Oklahoma Oil and Gas Corp.

As reported in Note 14 to the Company's Consolidated Financial Statements in the Company's Form 10-K for the year ended December 31, 2005, OGE Energy Corp., Enogex, Central Oklahoma Oil and Gas Corp. ("COOG"), Natural Gas Storage Corporation ("NGSC") and individual shareholders of COOG and NGSC have been involved in legal proceedings relating to a gas storage agreement and associated agreements. In the actions against the individual shareholders of COOG and NGSC in the U.S. District Court for Western District of Oklahoma, the jury, in 2004, ruled in favor of the Company and Enogex for approximately $6.6 million ("Thrash Fraudulent Transfer Judgment"). In April 2005, the defendants filed an appeal in the Tenth Circuit Court of Appeals and on September 14, 2005, the defendants posted a cash bond for approximately $6.9 million to stay the execution of the Thrash Fraudulent Transfer Judgment pending appeal. On December 30, 2005, the parties reached a settlement of the Thrash Fraudulent Transfer Judgment and other COOG-related matters discussed in the Company's Form 10-K for the year ended December 31, 2005. On March 8, 2006, the individual defendants paid approximately $5.2 million (the “Settlement Amount”) to the Company and Enogex. Thereafter, the parties dismissed the pending appeal of the Thrash Fraudulent Transfer Judgment to the Tenth Circuit. The Settlement Amount has been accounted for as a gain in the Company’s Condensed Consolidated Financial Statements in the first quarter of 2006. The Company now considers these matters closed.

Calpine Corporation Bankruptcy

Calpine Corporation, Calpine Energy Services, L.P., and several other affiliates (collectively “Calpine”) voluntarily filed for Chapter 11 bankruptcy protection from creditors on December 20, 2005 (Case No. 05-60200 (BRL)) United States Bankruptcy Court, S.D. of New York. Enogex provides natural gas transportation services pursuant to long-term contracts to two Calpine-owned power generation plants in Oklahoma. Calpine is continuing to operate the plants and request services pursuant to the contracts. The total unpaid amount due to Enogex from Calpine is approximately $0.3 million which has been fully reserved on the Company’s books. Approximately $0.2 million of this amount relates to Calpine’s dispute of a portion of a monthly demand payment in July 2005. Enogex believes this amount is due and owing and subject to recoupment and/or set off rights. The remaining amounts relate to unpaid invoices for transportation services provided to Calpine immediately prior to its bankruptcy filing. It remains unknown whether Calpine, in its bankruptcy proceedings, will affirm or reject these agreements with Enogex.

A Calpine-owned power generation plant in Oklahoma is contractually obligated to provide capacity and energy to OG&E. The Calpine plant also pays, through the Southwest Power Pool (“SPP”), for transmission services provided to OG&E. OG&E expects both arrangements to remain in effect; however, whether Calpine in its bankruptcy proceedings will ultimately reject these agreements with OG&E is unknown.

G.M. Oil Properties Litigation

On March 8, 2005, Enogex was served with a putative class action filed by G.M. Oil Properties, Inc. in the District Court of Comanche County, Oklahoma. The petition alleges that Enogex exercises a monopoly power with respect to its gathering facilities within the state of Oklahoma. The petition further alleges that, due to the alleged monopoly power, Enogex has caused damage to the plaintiff and other small gas producers and marketers. A settlement of this case was

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reached with the named plaintiffs and the case brought by the named plaintiffs was dismissed with prejudice. Pursuant to the settlement, a certain segment of gathering pipeline was sold to G.M. Oil Properties with the Company recognizing a loss of less than $0.1 million. This case is now closed.

Farris Buser Litigation

On July 22, 2005, Enogex along with certain other unaffiliated co-defendants was served with a purported class action which had been filed on February 7, 2005 by Farris Buser and other named plaintiffs in the District Court of Canadian County, Oklahoma. The plaintiffs’ own royalty interests in certain oil and gas producing properties and allege they have been under-compensated by the named defendants, including the Enogex companies, relating to the sale of liquid hydrocarbons recovered during the transportation of natural gas from the plaintiffs’ wells. The plaintiffs’ assert breach of contract, implied covenants, obligation, fiduciary duty, unjust enrichment, conspiracy and fraud causes of action and claim actual damages in excess of $10,000, plus attorneys’ fees and costs, and punitive damages in excess of $10,000. The Enogex companies filed a motion to dismiss which was granted on November 18, 2005, subject to the plaintiffs’ right to conduct discovery and the possible re-filing of their allegations in the petition against Enogex companies. On September 19, 2005, the co-defendants, BP America, Inc. and BP America Production Co., filed a cross claim against Enogex Products Corporation (“Products”) seeking indemnification and/or contribution from Products based upon the 1997 sale of a third party interest in one of Products natural gas processing plants. The court-established date for the refiling of the allegations in the petition was extended until May 17, 2006, and, on such date, the plaintiffs filed an amended petition against the Enogex companies. Enogex expects to file a motion to dismiss the amended petition on August 2, 2006. Based on its investigation to date, the Company believes these claims and cross claims in this lawsuit are without merit and intends to vigorously defend this case.

Osterhout Litigation

On June 19, 2006, two OG&E customers brought a putative class action, on behalf of all similarly situated customers, in the District Court of Creek County, Oklahoma, challenging certain charges on OG&E’s electric bills. The plaintiffs claim that OG&E improperly charged sales tax based on franchise fee charges paid by its customers. The plaintiffs also challenge certain franchise fee charges, contending that such fees are more than is allowed under Oklahoma law. At the present time, OG&E believes that this case is without merit and intends to vigorously defend this case.

Environmental Laws and Regulations

OG&E

Air

On March 25, 2005, the Environmental Protection Agency ("EPA") issued the Clean Air Mercury Rule ("CAMR") to limit mercury emissions from coal-fired boilers. On May 31, 2006, the EPA issued a ruling which amended and clarified minor portions of CAMR. The CAMR is currently subject to legal challenges. The CAMR requires reductions in mercury in two phases, Phase I beginning in 2010 and Phase II in 2018. The CAMR is based on the cap and trade program that will allow utilities to purchase mercury allowances (if available) rather than reduce emissions. It is anticipated that OG&E will need to obtain allowances or reduce its mercury emissions in Phase II by approximately 70 percent. The CAMR requires each state to adopt the requirements of the federal rule into a state implementation plan. However, the CAMR does not preclude states from developing more stringent mercury reduction requirements. The state of Oklahoma has proposed to incorporate the EPA's CAMR into the state implementation program. However, the state has proposed to retain one percent of the EPA allocated allowances and auction those allowances in order to offset their costs of the mercury program. OG&E is currently participating in the rulemaking process and anticipates the rulemaking to be completed by the end of 2006. Because rulemaking is in progress, the cost to install any mercury controls is uncertain at this time but is expected to be significant to meet Phase II requirements in 2018. The state implementation plan will also require continuous monitoring of mercury emissions from OG&E's coal-fired boilers beginning in 2009. The cost of monitoring equipment is estimated at approximately $2.5 million. However, the cost to comply with the CAMR monitoring requirements will be in addition to the cost of other emissions monitoring that is already in place pursuant to Title IV of the Clean Air Act Amendments of 1990.

As reported previously, in September 2005, the Oklahoma Department of Environmental Quality ("ODEQ") informally notified affected utilities that they would be required to perform a study to determine their impact on visibility in Federal Class I areas. OG&E and other affected industries in Oklahoma initiated a modeling study that was completed in July 2006. Because the preliminary results indicate a significant impact from OG&E's Sooner, Muskogee, Seminole and Horseshoe Lake generating stations on visibility in Class I areas in both Oklahoma and Arkansas, additional modeling may

be required with a projected completion date by the end of 2006. Any proposed reductions or controls must be submitted to the ODEQ by March 2007. OG&E will have five years from the date of approval of a compliance plan by the EPA to institute any required reductions. Depending on the outcome of the final analysis and compliance plan, significant capital and operating expenditures may be required for OG&E's Sooner, Muskogee, Seminole and Horseshoe Lake generating stations. OG&E expects that any necessary environmental expenditures will qualify as part of a pre-approved plan to handle state and federally mandated environmental upgrades which will be recoverable under House Bill 1910.

Currently, the EPA has designated Oklahoma "in attainment" with the ambient standard for ozone. However, elevated readings on June 21 and 22, 2005, and additional high readings thus far in 2006 in both Tulsa and Oklahoma City could lead to redesignation of these areas as non-attainment. Both Tulsa and Oklahoma City have entered into an "Early Action Compact" with the EPA whereby voluntary measures will be enacted to reduce ozone. If either Tulsa or Oklahoma City became non-attainment, reductions in nitrogen oxides emissions from OG&E's generating facilities may be required.

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. 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 18 below, in Item 1 of Part II of this Form 10-Q, in Notes 14 and 15 of Notes to the Company's Consolidated Financial Statements included in the Company's Form 10-K for the year ended December 31, 2005 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.

18. Rate Matters and Regulation

Except as set forth below, the circumstances set forth in Note 15 to the Company's Consolidated Financial Statements included in the Company's Form 10-K for the year ended December 31, 2005 appropriately represent, in all material respects, the current status of any regulatory matters.

Completed Regulatory Matters

Acquisition of Power Plant

On July 9, 2004, OG&E completed the acquisition of NRG McClain LLC's 77 percent interest in the 520 megawatt ("MW") natural gas-fired combined cycle NRG McClain Station ("McClain Plant"). This transaction was intended to satisfy the requirement in the 2002 agreed-upon settlement of an OG&E rate case (the "Settlement Agreement") to acquire electric generation of not less than 400 MW's. The McClain Plant, which includes natural gas-fired combined cycle combustion turbine units, is located near Newcastle, Oklahoma in McClain County, Oklahoma. The McClain Plant began operating in 2001.

The closing of the purchase of the McClain Plant was subject to approval from the FERC. The FERC's July 2, 2004 approval was based on an offer of settlement in which OG&E proposed, among other things, to install certain new transmission facilities and to hire an independent market monitor to oversee OG&E's activity for a limited period. As part of the July 2, 2004 order, OG&E agreed to undertake the following mitigation measures: (i) install certain transmission facilities designed to result in up to 600 MW's of available transfer capability ("ATC") from the Redbud Energy LP ("Redbud") facility to the OG&E control area; (ii) pending completion of these transmission upgrades, provide up to 600 MW's of ATC into OG&E's control area from the Redbud plant through changes to the dispatch of OG&E's generating units; and (iii) hire an independent market monitor to oversee OG&E's activity in its control area until the SPP implements a market monitor for the SPP regional transmission organization ("RTO"). OG&E completed the installation of the capital improvements and notified the FERC in writing on May 31, 2005 that these were completed. OG&E's obligation to redispatch its system to make 600 MW's of ATC available to the Redbud power plant terminated upon completion of the transmission upgrades. The independent market monitor described above has submitted quarterly reports each covering the quarterly periods subsequent to the McClain Plant acquisition. Based on an analysis of transmission congestion data on OG&E's system, along with data on purchases and sales, generation dispatch data and power flows on OG&E's tie lines, the market monitor has concluded that OG&E has not acted in an anticompetitive manner through either dispatch of its generation or operation of its

transmission system. Further, in the review of the disposition of requests for transmission service, the independent market monitor detected no improper behavior with regard to access to OG&E's transmission system. In August 2005, the market monitor initiated a special investigation into the circumstances surrounding the denial by the SPP of a request by Redbud for 440 MW's in June 2005 of firm transmission service to OG&E. In its third quarter 2005 report, the market monitor concluded that differences in the SPP modeling assumptions and an error in modeling made by the SPP were the primary causes for the denial of service. The market monitor further stated that, if the FERC's July 2, 2004 order was based on the assumption that the McClain generating unit was not running to serve OG&E's load, the ATC created by the mitigation upgrades completed by OG&E in response to the FERC's July 2, 2004 order matched the claims made by OG&E. On September 21, 2005, the FERC issued a letter requesting OG&E to provide information to confirm that the transmission facilities that OG&E constructed to mitigate the effects of the acquisition of the McClain interest resulted in 600 MW's of ATC from Redbud to the OG&E control area and that OG&E has fulfilled it obligations under the prior order. On October 3, 2005, OG&E responded that the facilities it constructed complied with the settlement the FERC approved regarding the acquisition of the McClain interest and resulted in the 600 MW's of ATC. Redbud responded that, when it requested transmission service commencing in June 2005 after the facilities were completed, the SPP denied Redbud's request for service and, therefore, argued that the ATC was not created. OG&E explained that the SPP's denial of service to Redbud was due to an error by the SPP. Nonetheless Redbud and OG&E filed additional pleadings addressing the ATC. On June 20, 2006, the FERC issued an order that OG&E has fully satisfied all of the mitigation requirements associated with the McClain Plant acquisition. Parties in this matter had 30 days to request a rehearing. No request for rehearing was filed with the FERC and OG&E believes the order is final.

OG&E expects the addition of the McClain Plant, including the effects of an interim power purchase agreement OG&E had with NRG McClain LLC while OG&E was awaiting regulatory approval to complete the acquisition, will provide savings, over a three-year period, in excess of $75.0 million to its Oklahoma customers. In the event OG&E is unable to demonstrate at least $75.0 million in savings to its customers during this 36-month period, OG&E will be required to credit its Oklahoma customers any unrealized savings below $75.0 million as determined at the end of the 36-month period ending December 31, 2006. At this time, OG&E believes that it will achieve at least $75.0 million in savings during this period.

Enogex FERC Section 311 Filing and FERC 2006 Fuel Filing

The FERC requires all intrastate pipelines offering 311 service to file a rate case every three years. Enogex must file its next rate case no later than October 1, 2007.

As required by the fuel tracker provisions of its Statement of Operating Conditions, Enogex made its annual fuel filing for the 2006 fuel year on November 15, 2005. As agreed in the settlement in Enogex's most recent Section 311 rate case, the fuel filing established an East Zone fuel percentage and a West Zone fuel percentage to be recalculated annually to replace the system-wide fuel percentage previously established annually for the whole Enogex system. By order dated April 13, 2006, the FERC approved and accepted Enogex's November 2005 fuel tracker filing and approved the zonal fuel factors as fair and equitable effective January 1, 2006. On June 30, 2006, Enogex filed to revise the zonal fuel percentages for the remainder of the 2006 fuel year. Enogex proposes to use zonal fuel percentages based upon the actual fuel usage from January 1, 2006 through April 30, 2006 rather than continuing with the estimated percentages that were filed with the initial East and West Zone on November 15, 2005. Interventions and protests with respect to the revised fuel percentages were due on or before July 21, 2006. To date, six parties have intervened but there have been no protests.

Gas Transportation and Storage Agreement

As part of the 2002 Settlement Agreement, OG&E also agreed to consider competitive bidding as a basis to select its provider for gas transportation service to its natural gas-fired generation facilities pursuant to the terms set forth in the Settlement Agreement. Because the required integrated service was not available in the marketplace from parties other than Enogex, OG&E advised the OCC that, after careful consideration, competitive bidding for gas transportation was rejected in favor of a new intrastate integrated, firm no-notice load following gas transportation and storage services agreement with Enogex. This seven-year agreement provides for gas transportation and storage services for each of OG&E's natural gas-fired generation facilities. OG&E will pay Enogex annual demand fees of approximately $46.8 million for the right to transport specified maximum daily quantities ("MDQ") and maximum hourly quantities ("MHQ") of gas at various minimum gas delivery pressures depending on the operational needs of the individual generating facility. In addition, OG&E supplies system fuel in-kind for its pro-rata share of actual fuel and lost and unaccounted for gas on the transportation system. To the extent OG&E transports gas in quantities exceeding the prescribed MDQ's or MHQ's, it pays an overrun service charge. During the three months ended June 30, 2006 and 2005, OG&E paid Enogex approximately $11.8 million and $11.9 million, respectively, for gas transportation and storage services. During each of the six month periods ended June 30, 2006 and 2005, OG&E paid Enogex approximately $23.7 million for gas transportation and storage services.

On July 14, 2005, the OCC issued an order in this case approving a $41.9 million annual recovery. The OCC order disallowed the recovery by OG&E of the amount that Enogex charges OG&E for the cost of fuel used, or otherwise unaccounted for, in providing natural gas transportation and storage service to OG&E. Over the last three years, this amount has ranged from approximately $1.2 million to $3.7 million annually. This amount was approximately $1.2 million in 2005 and is projected to be approximately $1.3 million in 2006. The OCC's order required OG&E to refund to its Oklahoma customers the difference between the amounts collected from such customers in the past based on an annual rate of $46.8 million for gas transportation and storage services and the $41.9 million annual rate authorized by the OCC's order. Based on the order, OG&E's refund obligation was approximately $8.8 million. OG&E began refunding this obligation in September 2005 through its automatic fuel adjustment clause. The balance of the refund obligation was approximately $1.9 million at June 30, 2006.

In connection with the Enogex gas transportation and storage agreement, OG&E also recorded a refund obligation in Arkansas of approximately $1.1 million at December 31, 2005. OG&E provided to the APSC the OCC evidence and above findings showing that the Arkansas refund was calculated consistently with the Oklahoma refund. OG&E applied the refund obligation to its fuel clause under recoveries balance in April and customers began receiving this refund in April 2006 and will continue through March 2007.

Security Enhancements

On April 8, 2002, OG&E filed a joint application with the OCC requesting approval for security investments and a rider to recover these costs from the ratepayers. On October 28, 2004, all parties signed a joint stipulation that contains the OCC Staff's recommendations and authorizes up to a $5 million annual recovery from OG&E's customers for security enhancement. On December 21, 2004, the OCC issued an order approving the security rider. OG&E implemented the security rider with the first billing period in July 2006 which will initially charge OG&E's Oklahoma customers approximately $2.4 million annually. The OCC authorized tariff provides that the security rider may be updated quarterly.

Competitive Bidding, Prudence Reviews and Other Rules for Electric Utility Providers

On March 10, 2005, the OCC filed Cause No. PUD 200500129 regarding "Inquiry of the Oklahoma Corporation Commission into Guidelines for Establishing Rules for Competitive Bidding and Prudence Reviews for Electric Utility Providers." On June 10, 2005, the OCC voted to close this notice of inquiry and directed the OCC Staff to open a rulemaking to address the competitive bidding issue for electric utilities and other matters. Rules were adopted by the OCC on January 18, 2006 and became effective on April 3, 2006. The new rules: (i) establish a competitive procurement process for purchase of long-term electric generation and long-term fuel supplies; (ii) clarify existing law by requiring that a prudence review of utility fuel and generation procurement be conducted no less frequently than every two years; (iii) require a utility to submit an integrated resource plan to the OCC every three years, with the first plan due on October 1, 2006; and (iv) establish a process whereby a utility may seek pre-approval for recovery of costs associated with transmission upgrades, generation facility modifications caused by environmental requirements and the purchase or construction of generation facilities. OG&E does not expect these rules to have a significant impact on its operations.

OG&E SO2 Allowance Filing

On February 10, 2006, OG&E, the OCC Staff and AES Shady Point ("AES") filed a joint application with the OCC to determine the treatment of proceeds received from OG&E's sale of sulfur dioxide ("SO2") allowances and how these proceeds will be shared between OG&E and its customers for any sales after December 31, 2005. In the application, the parties propose that AES be held harmless from any reduction in OG&E's coal costs caused by the sale of SO2 allowances and that the proceeds of such sales are shared 80 percent with OG&E's Oklahoma customers and the remaining 20 percent to OG&E. A credit rider was requested to pass the proceeds from the sale of the SO2 allowances to Oklahoma customers. Any proceeds from the sale of SO2 allowances in the Arkansas and the FERC jurisdictions will flow through OG&E's automatic fuel adjustment clause. On June 5, 2006, the parties signed a settlement agreement which provides that the proceeds of such sales after December 31, 2005 are to be shared 90 percent with OG&E's Oklahoma customers and the remaining 10 percent to OG&E. On June 26, 2006, the OCC approved the settlement agreement, including the 90/10 sharing mechanism.

Consequently, during the second quarter of 2006, OG&E recorded approximately $0.8 million in SO2 sales proceeds from sales in 2006 which is included as an increase in Operating Revenues in the Condensed Consolidated Statement of Income.

Pending Regulatory Matters

Review of OG&E's Fuel Adjustment Clause for Calendar Year 2003 and 2004

The OCC routinely audits activity in OG&E's fuel adjustment clause for each calendar year. On March 18, 2005, the OCC Staff filed Cause No. PUD 200500140 regarding "Application of the Public Utility Division Director for Public Hearing to Review and Monitor OG&E's Fuel Adjustment Clause for Calendar Year 2003." On June 10, 2005, the OCC voted to combine this case with OG&E's recently completed Oklahoma rate case. On August 25, 2005, the OCC Staff filed Cause No. PUD 200500327 regarding "Application of the Public Utility Division Director for Public Hearing to Review and Monitor OG&E's Fuel Adjustment Clause for Calendar Year 2004." On September 27, 2005, the OCC consolidated these two proceedings into one proceeding. Intervenors in this proceeding include the Oklahoma Industrial Energy Consumers, AES, Redbud and PowerSmith Cogeneration Project, L.P. On May 8, 2006, the OCC issued a procedural schedule in these consolidated proceedings. OG&E filed supplemental testimony on June 30, 2006. Responsive testimony of the other parties is expected to be filed on August 4, 2006 and rebuttal testimony is due August 31, 2006. A hearing is scheduled to begin on September 25, 2006.

OG&E Wind Power Filing

On December 22, 2005, the Company issued a press release announcing that OG&E had entered into a non-binding letter of intent to purchase a 120 MW wind farm planned for construction in northwestern Oklahoma. Invenergy Wind Development Oklahoma LLC ("Invenergy LLC") would develop the new wind power-generation facility to be owned and operated by OG&E. The wind farm, north of Woodward in Harper County, is expected to cost approximately $195 million to construct, including the cost of transmission interconnection facilities. A definitive Agreement To Engineer, Procure and Construct Wind Generation Energy System ("EPC Contract") was reached on February 20, 2006, subject to various conditions. Those conditions include agreement by the parties as to certain exhibits to the EPC Contract, approval of the EPC Contract by the OG&E Board of Directors and approval of the EPC Contract by the governing body for Invenergy LLC, all of which have been completed. In addition, 90 days subsequent to the occurrence of these events, OG&E or Invenergy LLC have the unilateral right to terminate the EPC Contract if certain additional events have not occurred, including the following: (i) OCC approval of the terms of the EPC Contract and of a recovery rider providing OG&E the opportunity to recover the costs associated with the wind facility, including transmission interconnection and transmission upgrade costs; (ii) completion by the SPP of all necessary transmission studies; (iii) Invenergy LLC's acquisition of certain land agreements; (iv) Invenergy LLC's execution of a contract acceptable to OG&E with a Balance of Work ("BOW") contractor; and (v) Invenergy LLC's acquisition of certain permits. If all of these conditions are met, the new wind farm is expected to be constructed and producing power on or before December 31, 2006. On April 6, 2006, a settlement agreement was filed with the OCC which, among other things, requested approval of the wind power EPC contract and a recovery rider for up to $205 million in construction costs and allowance for funds used during construction. The settlement also indicated that OG&E shall file for a general rate review during 2009 which will permit the OCC to issue an order no later than December 31, 2009 placing the wind farm in OG&E's rate base. On April 11, 2006, the administrative law judge ("ALJ") in this proceeding recommended approval of the settlement agreement. On April 28, 2006, the OCC issued a unanimous order approving the settlement agreement. The issuance of this order satisfied requirement (i) above. OG&E expects the recovery rider will be implemented in January 2007 and remain in effect through December 2009. OG&E estimates that the recovery rider will initially result in a recovery of $22.6 million annually, which amount will decline over the life of the facility. OG&E filed an application with the APSC on June 8, 2006 for approval to allocate to Arkansas the portion of the wind project not being recovered in rates in Oklahoma and included a request for recovery of approximately $2.1 million annually for the Arkansas portion of the wind project in its Arkansas rate case which was filed on July 28, 2006. On May 5, 2006 the SPP Interconnection Agreement was executed by the necessary parties and on May 9, 2006, the SPP Transmission Service Request No. 1032973 agreement was signed by the necessary parties, satisfying requirement (ii) above. On June 13, 2006, Invenergy and OG&E confirmed to each other that requirements (iii), (iv) and (v) had been met thus terminating either party's unilateral right to terminate the EPC Contract for failure to meet the conditions precedent. Currently, OG&E is working on the construction of the substation and generation tie line to connect the wind farm to OG&E's transmission system which is expected to be completed by September 15, 2006. The BOW contractor has begun work on the actual construction of the wind farm itself, with a targeted completion date of December 31, 2006.

OG&E Arkansas Rate Case Filing

In January 2006, OG&E began developing a rate case filing for the Arkansas jurisdiction. OG&E filed a notice with the APSC on May 1, 2006 of its intent to file a rate case in July 2006. On July 28, 2006, OG&E filed with the APSC an application for an annual rate increase of approximately $13.5 million to recover, among other things, its investment in, and the operating expenses of, the McClain Plant, the wind power project and the costs of electric system expansion and upgrades based on a return on equity of 11.75 percent. A decision by the APSC on the rate case application should occur in the second quarter of 2007.

Uniform Fuel Adjustment Clause Filing

On January 23, 2006, the Director of the Public Utility Division of the OCC filed Cause No. PUD 200600012 regarding an application to review the OCC's regulation of the automatic rate adjustment clauses of all public energy utilities operating in Oklahoma and subject to the OCC's jurisdiction. A technical conference for electric utilities was held on March 17, 2006. At this time, OG&E does not believe the outcome of this proceeding will significantly impact the Company.

Proposed Construction of Power Plant

On July 18, 2006, the Company announced plans for OG&E to partner with American Electric Power's Public Service Company of Oklahoma subsidiary ("PSO") and the Oklahoma Municipal Power Authority ("OMPA") to build a new 950 MW coal unit at OG&E's existing Sooner plant near Red Rock, Oklahoma. The estimated $1.8 billion project is the result of PSO's December 2005 request for proposal in which it sought bids for up to 600 MW's of new base load generation to be available to PSO by the summer of 2011. Base load units run year-round to ensure adequate supplies of low-cost electricity. The unit, to be called Red Rock, is expected to be one of the cleanest of its size using coal from the Powder River Basin, which is located near Gillette, Wyoming. OG&E will operate the facility and own approximately 42 percent of the project. PSO will own 50 percent and the OMPA will own approximately 8 percent. OG&E expects to sign a contract by the end of August and expects construction to begin in 2007. Completion of the power plant is targeted before the summer of 2011. The project is contingent upon the successful completion of contract negotiations, which have already begun, and the necessary regulatory approvals.

FERC Audit

On May 29, 2006, the FERC notified OG&E that it was commencing an audit to determine whether and how OG&E is complying with: (i) its Open Access Transmission Tariff; (ii) requirements of its market-based rate authorization; (iii) Standards of Conduct and Open Access Same-Time Information System; and (iv) wholesale fuel adjustment clause tariff and other requirements contained in the FERC regulations. Over the past several years, the FERC has conducted numerous audits of utilities across the country to ensure regulatory compliance. OG&E is currently in the process of providing information to the FERC. OG&E cannot predict either the final outcome or the timing of the completion of this audit.

Southwest Power Pool

The SPP filed on June 15, 2005, Docket No. ER05-1118, to create a real-time, offer-based imbalance energy market which will require cash settlements for over or under generation. Market participants, including OG&E, will be required to submit resource plans and can submit offer curves for each resource available for dispatch. In addition, the filing contains provisions allowing the SPP to order certain dispatching of generating units and a market monitoring plan which provides a clear set of rules, the potential consequences if the rules are violated and the areas in which an independent market monitor will examine and report. On September 19, 2005, the FERC rejected the June 15, 2005 filing; however, the FERC provided guidance for the SPP's follow-up filing. On January 4, 2006, the SPP filed its follow-up filing in Docket No. ER06-451 by submitting tariff revisions to incorporate imbalance energy market and market monitoring procedures. On March 20, 2006, the FERC issued an order on the proposed tariff revisions which conditionally accepted a portion of the filing and suspended and rejected other portions of the filing. As a result, the scheduled implementation date of the imbalance energy market was delayed from May 1, 2006 to no earlier than October 1, 2006. The SPP made two compliance filings consistent with the March 20, 2006 FERC order, and continues to work on other issues as directed by the FERC. On July 25, 2006, the SPP Board of Directors voted to implement the imbalance energy market on November 1, 2006 pending a certification of readiness by the SPP to the FERC on October 1, 2006. OG&E expects minimal additional costs related to market systems implementation due to the delay in the effective date of the imbalance energy market.

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 April 14, 2004, the FERC replaced the supply margin assessment test and issued: (1) interim requirements for the FERC jurisdictional electric utilities that have been granted authority to make wholesale sales at market-based rates; and (2) an order initiating a new rulemaking on future market-based rates authorizations. The interim method for analyzing generation market power requires two assessments – whether the utility is a pivotal supplier based on a control area's annual peak demand and whether the utility exceeds certain market share thresholds on a seasonal basis. If an applicant does not pass either assessment, the FERC will presume that the utility can exercise generation market power and will initiate an investigation into the scope of the applicant's market power. The FERC will allow a utility to rebut that presumption through the submission of additional information. If an applicant is found to have generation market power, the applicant must propose a market power mitigation plan. The new interim assessment methods are applicable to all market-based rate sellers pending the outcome of the rulemaking described below. 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 two interim tests described above. In the rulemaking proceeding, the FERC is seeking comments on the adequacy of the FERC's current analysis of market-based rate filings, including the adequacy of the new "interim" assessment of generation market power. OG&E and OERI submitted a compliance filing to the FERC on February 7, 2005 which 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 the OG&E control area. OG&E and OERI provided an explanation as to why their failure of the market share screen in the OG&E control area should not be viewed as an indication that they can exercise generation market power. One party, Redbud, protested the OG&E and OERI filing and proposed that the FERC require OG&E to adopt an economic dispatch program as a means to mitigate OG&E's and OERI's generation market power. On March 15, 2005, OG&E and OERI responded to Redbud's protest. In that response OG&E and OERI reiterated that the information they initially filed demonstrates that they cannot exercise market power and that Redbud's proposal is beyond the scope of the proceeding. Another party, AES, intervened and protested OG&E's and OERI's filing.

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 the OG&E 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. No party filed interventions or comments on OG&E's and OERI's August 8, 2005 filing. 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 the OG&E 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 the OG&E control area. The FERC also expanded the scope of the proposed mitigation to all sales made within the OG&E control area (instead of only to sales sinking to load within the OG&E 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, 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 markets administered by the SPP at market-based rates.

National Energy Legislation

In August 2005, Congress passed and the President signed into law a comprehensive energy bill, portions of which are of interest to the Company and to the industry. There are several provisions in the bill that have a positive impact on the Company. Provisions minimizing the risk of future uneconomic purchased power contracts forced on the Company under PURPA, tax incentives for investment in electric transmission and gas pipeline systems, mandatory reliability requirements by the North American Electric Reliability Council with oversight by the FERC and improved FERC siting authority for construction of electric transmission in disputed areas are included in the new law. Another significant provision for the utility industry is the repeal of the Public Utility Holding Company Act of 1935. This provision has minimal impact on the

current operations of the Company. The FERC is in the process of developing regulations and policies mandated by the new energy act, some of which could have significance for electric utilities such as OG&E. In particular, OG&E will closely monitor the FERC's implementation of the new statute's conditional elimination of utilities' obligation to purchase power from cogenerators. Similarly, OG&E will closely monitor the respective FERC and U.S. Department of Energy proceedings with regard to the selection of the nation's Electric Reliability Organization ("ERO"), federal oversight and approval of the ERO's mandatory reliability standards, new transmission incentives and the concept of economic or efficient dispatch.

State Legislative Initiatives

Oklahoma

The 2006 legislative session concluded on May 26, 2006, with no legislation being passed that had a material impact on the Company. One bill, House Bill 1386 was introduced in the 2005 session and was carried over into the 2006 session. That bill, if passed, could have an impact on the Company's ability to compete with other utility providers. The bill proposed that utilities be able to continue to serve and expand, if so desired, in service territories in which they currently serve but which a municipality annexes. OG&E believes current case law authorizes utilities to serve and expand in an area described above. House Bill 1386 would codify OG&E's belief. The bill failed to be heard in the Senate in 2006.

19. Fair Value of Financial Instruments

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, 2005.

	June 30, 2006		December 31, 2005	
(In millions)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Price Risk Management Assets				
Energy Trading Contracts	**$ 45.5**	**$ 45.5**	$ 125.4	$ 125.4
Price Risk Management Liabilities				
Energy Trading Contracts	**$ 38.0**	**$ 38.0**	$ 120.1	$ 120.1
Long-Term Debt				
Senior Notes	**$ 807.1**	**$ 789.6**	$ 587.8	$ 612.2
Other	---	---	220.0	220.0

The carrying value of the financial instruments on the Condensed Consolidated Balance Sheets not otherwise discussed above approximates fair value except for long-term debt which is valued at the carrying amount. The valuation of the Company's energy trading contracts was determined primarily 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 and the potential impact of liquidating the position in an orderly manner over a reasonable period of time. 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. See Note 6 for a discussion of Enogex's energy trading contracts with set off provisions.

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 two business segments, the Electric Utility and the Natural Gas Pipeline segments.

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, 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.

The operations of the Natural Gas Pipeline segment are conducted through Enogex Inc. and its subsidiaries ("Enogex") and consist of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas; and (iii) the marketing of natural gas. The vast majority of Enogex's natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. In May 2006, Enogex Gas Gathering, L.L.C. ("Gathering"), a wholly-owned subsidiary of Enogex Inc., sold certain gas gathering assets in the Kinta, Oklahoma, area (see "Results of Operations – Enogex – Discontinued Operations" for a further discussion).

Forward-Looking Statements

Except for the historical statements contained herein, the matters discussed in the following discussion and analysis, including the discussion in "Outlook", 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 vary materially. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including the availability of credit, actions of rating agencies and their impact on capital expenditures; the Company's ability and the ability of its subsidiaries to obtain financing on favorable terms; prices of electricity, coal, natural gas and natural gas liquids, each on a stand-alone basis and in relation to each other; business conditions in the energy industry; 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; federal or state legislation and regulatory decisions and initiatives that affect cost and investment recovery, have an impact on rate structures or affect the speed and degree to which competition enters the Company's markets; environmental laws and regulations that may impact the Company's operations; changes in accounting standards, rules or guidelines; 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; and other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission including Risk Factors and Exhibit 99.01 to the Company's Form 10-K for the year ended December 31, 2005.

Overview

Summary of Operating Results

Quarter ended June 30, 2006 as compared to quarter ended June 30, 2005

The Company reported net income of approximately $93.7 million, or $1.02 per diluted share, as compared to approximately $38.5 million, or $0.42 per diluted share, for the three months ended June 30, 2006 and 2005, respectively. The increase in net income during the three months ended June 30, 2006 as compared to the same period in 2005 was primarily due to:

- Enogex's operations, including discontinued operations, reported net income of approximately $51.3 million, or $0.56 per diluted share of the Company's common stock (of which $0.39 per diluted share was attributable to discontinued operations), as compared to approximately $11.3 million, or $0.12 per diluted share (of which $0.03 per diluted share was attributable to discontinued operations), during the three months ended June 30, 2006 and 2005, respectively;
- OG&E reported net income of approximately $44.0 million, or $0.48 per diluted share of the Company's common stock, as compared to approximately $29.7 million, or $0.33 per diluted share, during the three months ended June 30, 2006 and 2005, respectively; and
- a net loss at the holding company of approximately $1.6 million, or $0.02 per diluted share as compared to a net loss of approximately $2.5 million, or $0.03 per diluted share, during the three months ended June 30, 2006 and 2005, respectively.

Six months ended June 30, 2006 as compared to six months ended June 30, 2005

The Company reported net income of approximately $118.6 million, or $1.29 per diluted share, as compared to approximately $43.8 million, or $0.48 per diluted share, for the six months ended June 30, 2006 and 2005, respectively. The increase in net income during the six months ended June 30, 2006 as compared to the same period in 2005 was primarily due to:

- Enogex's operations, including discontinued operations, reported net income of approximately $78.3 million, or $0.85 per diluted share of the Company's common stock (of which $0.40 per diluted share was attributable to discontinued operations), as compared to approximately $19.4 million, or $0.21 per diluted share (of which $0.07 per diluted share was attributable to discontinued operations), during the six months ended June 30, 2006 and 2005, respectively;
- OG&E reported net income of approximately $42.9 million, or $0.47 per diluted share of the Company's common stock, as compared to approximately $28.0 million, or $0.31per diluted share, during the six months ended June 30, 2006 and 2005, respectively; and
- a net loss at the holding company of approximately $2.6 million, or $0.03 per diluted share as compared to a net loss of approximately $3.6 million, or $0.04 per diluted share, during the six months ended June 30, 2006 and 2005, respectively.

Regulatory Matters

OG&E Wind Power Filing

On December 22, 2005, the Company issued a press release announcing that OG&E had entered into a non-binding letter of intent to purchase a 120 megawatt ("MW") wind farm planned for construction in northwestern Oklahoma. Invenergy Wind Development Oklahoma LLC ("Invenergy LLC") would develop the new wind power-generation facility to be owned and operated by OG&E. The wind farm, north of Woodward in Harper County, is expected to cost approximately $195 million to construct, including the cost of transmission interconnection facilities. A definitive Agreement To Engineer, Procure and Construct Wind Generation Energy System ("EPC Contract") was reached on February 20, 2006, subject to various conditions, all of which have now been met. Currently, OG&E is working on the construction of the substation and generation tie line to connect the wind farm to OG&E's transmission system which is expected to be completed by September 15, 2006. The Balance of Work contractor has begun work on the actual construction of the wind farm itself, with a targeted completion date of December 31, 2006. On April 28, 2006, the OCC approved a settlement agreement approving the wind power EPC contract and a recovery rider for up to $205 million in construction costs and allowance for funds used during construction. The settlement also indicated that OG&E shall file for a general rate review during 2009 which will permit the OCC to issue an order no later than December 31, 2009 placing the wind farm in OG&E's rate base. OG&E filed an application with the APSC on June 8, 2006 for approval to allocate to Arkansas the portion of the wind project not being recovered in rates in Oklahoma and included a request for recovery of approximately $2.1 million annually for the Arkansas portion of the wind project in its Arkansas rate case which was filed on July 28, 2006.

OG&E Arkansas Rate Case Filing

In January 2006, OG&E began developing a rate case filing for the Arkansas jurisdiction. OG&E filed a notice with the APSC on May 1, 2006 of its intent to file a rate case in July 2006. On July 28, 2006, OG&E filed with the APSC an application for an annual rate increase of approximately $13.5 million to recover, among other things, its investment in, and the operating expenses of, the McClain Plant, the wind power project and the costs of electric system expansion and upgrades based on a return on equity of 11.75 percent. A decision by the APSC on the rate case application should occur in the second quarter of 2007.

Proposed Construction of Power Plant

On July 18, 2006, the Company announced plans for OG&E to partner with American Electric Power's Public Service Company of Oklahoma subsidiary ("PSO") and the Oklahoma Municipal Power Authority ("OMPA") to build a new 950 MW coal unit at OG&E's existing Sooner plant near Red Rock, Oklahoma. The estimated $1.8 billion project is the result of PSO's December 2005 request for proposal in which it sought bids for up to 600 MW's of new base load generation to be available to PSO by the summer of 2011. Base load units run year-round to ensure adequate supplies of low-cost electricity. The unit, to be called Red Rock, is expected to be one of the cleanest of its size using coal from the Powder River Basin, which is located near Gillette, Wyoming. OG&E will operate the facility and own approximately 42 percent of the project. PSO will own 50 percent and the OMPA will own approximately 8 percent. OG&E expects to sign a contract by the end of August and expects construction to begin in 2007. Completion of the power plant is targeted before the summer of 2011. The project is contingent upon the successful completion of contract negotiations, which have already begun, and the necessary regulatory approvals.

Enogex Expansion Projects

Enogex is also in the construction phase of a project to expand its gathering pipeline capacity on the west side of its system. This initial project is expected to be in service later in the third quarter. This expansion initiative should enable Enogex to benefit from economic growth opportunities in that marketplace. In addition to the initial expansion initiative, Enogex continues to have additional opportunities to expand the overall project.

Potential New Enogex Project

On November 4, 2005, Enogex announced that it had entered into a letter of intent with El Paso Corporation ("El Paso") that is designed to accelerate El Paso's Continental Connector Project. The letter of intent contemplated arrangements by which El Paso or an affiliate would execute an initial lease of up to 500,000 decatherms per day ("Dth/day") of capacity on the Enogex pipeline system, with an option to expand up to 1.5 million Dth/day, so that the leased Enogex pipeline capacity would become an integral part of the Continental Connector Project. These arrangements would significantly reduce the amount of new mainline construction required for the project, resulting in less environmental disturbance and an earlier in-service target date of winter 2007-2008.

Under the letter of intent, the Continental Connector Project would use existing or expanded El Paso pipeline systems to transport capacity-constrained natural gas from Rocky Mountain and mid-continent supply regions to Custer, Oklahoma. At Custer, this gas and local mid-continent production would be transported on existing and expanded Enogex systems for Continental Connector under a long-term lease arrangement for re-delivery in the vicinity of Bennington, Oklahoma. From there, gas would be transported on new El Paso pipeline facilities through the Perryville, Louisiana, Hub to a termination with Tennessee and Southern Natural Pipelines at Pugh, Mississippi.

The letter of intent expired on April 28, 2006. Nevertheless, the parties continue to seek to advance this project, likely at an initial level below the 500,000 Dth/day originally contemplated. However, a definitive project would be subject to various conditions, including definitive documentation and boards of directors' and regulatory approvals and there can be no assurance that the conditions will be satisfied. Pending satisfaction of these conditions, Enogex does not expect to incur material expenditures.

Outlook

The Company previously disclosed in its Form 10-Q for the quarter ended March 31, 2006 that its 2006 earnings guidance was $187 million to $205 million of net income, or $2.05 to $2.25 per diluted share as shown in the table below. The Company has increased its 2006 earnings guidance, excluding any gains on asset sales, to $207 million to $221 million of net income, or $2.25 to $2.40 per diluted share, assuming approximately 92.0 million average diluted shares outstanding, cash flow from operations of between $388 million and $402 million and an effective tax rate of 36.3 percent. The change in earnings guidance is due to an increase in the projected earnings at OG&E and Enogex and a decrease in the net loss at the holding company.

	Earnings guidance per Q1 2006 10-Q		Revised earnings guidance per Q2 2006 10-Q	
(In millions, except per share data)	Dollars	Diluted EPS	Dollars	Diluted EPS
OG&E	$124 - $128	$1.36 - $1.40	$134 - $139	$1.46 - $1.51
Enogex	$69 - $82	$0.75 - $0.90	$77 - $86	$0.84 - $0.93
Holding Company	($5) - ($6)	($0.05) - ($0.06)	($4) - ($4)	($0.04) - ($0.04)
Total	$187 - $205	$2.05 - $2.25	$207 - $221	$2.25 - $2.40

Key assumptions for 2006 are:

As shown above, OG&E's earnings guidance has been increased from $124 million to $128 million, or $1.36 to $1.40 per diluted share, to $134 million to $139 million, or $1.46 to $1.51 per diluted share. As explained below, this increase is attributable in part to more favorable weather in OG&E's service territory which increased the gross margin on revenues ("gross margin") by approximately $17 million, as compared to normal, during the six months ended June 30, 2006. 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 three percent as compared to a previously forecasted two percent growth rate;
- Oklahoma rate increase of approximately $42.3 million;
- Operating and maintenance expenses increase approximately $33 million primarily due to increased employee and benefit costs as well as costs associated with the acquisition of the McClain Plant and a possible $20 million pension settlement charge in the fourth quarter of 2006 based on a potential range of between $15 million and $26 million;
- Other expense increases approximately $8.5 million due in large part to a loss in the second quarter related to the retirement of certain generating assets dedicated to a large industrial customer;
- Interest costs increase approximately $8 million primarily due to higher levels of long-term debt and higher interest rates associated with variable debt;
- Capital expenditures for investment in OG&E's generation, transmission and distribution system are approximately $443 million in 2006, which includes capital expenditures of up to $205 million associated with OG&E's wind power project; and
- Funding for the Company's pension plan of $90 million in 2006, of which up to $69.9 million may be allocated to OG&E.

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 $69 million to $82 million, or $0.75 to $0.90 per diluted share, to $77 million to $86 million, or $0.84 to $0.93 per diluted share. Key factors and assumptions underlying this guidance include:

- Total Enogex anticipated gross margin of approximately $312 million to $327 million as compared to approximately $303 million to $324 million assumed in the previous first quarter 2006 earnings guidance. The revised guidance includes:
    - Transportation and storage gross margin contribution of approximately $131 million as compared to approximately $135 million assumed in the previous first quarter 2006 earnings guidance. A key factor affecting the revised transportation and storage gross margin is a lower of cost or market adjustment to the value of storage inventories.

- Gathering and processing gross margin contribution of approximately $172 million to $187 million as compared to approximately $159 million to $180 million assumed in the previous first quarter 2006 earnings guidance. Key factors affecting the revised gathering and processing gross margin are:
  - Gross margin increase in Enogex's gathering and processing business in 2006 primarily due to higher commodity spreads offset by lower contractual gains as a result of lower natural gas prices;
  - Volumes in Enogex's gathering business slightly up from 2005;
  - Natural gas prices are $6.35 to $6.60 per Million British thermal unit ("MMBtu") in 2006;
  - Realized commodity spreads are $3.54 to $5.01 per MMBtu in 2006 as compared to $2.56 to $3.46 per MMBtu assumed in the previous first quarter 2006 earnings guidance. The commodity spread range is based on a combination of $4.07 realized for the first half of 2006 and approximately 65 percent of production volumes hedged for the remainder of 2006. The remaining production volumes are subject to market prices;
  - Average natural gas liquids prices are $0.93 to $1.22 per gallon in 2006 as compared to $0.99 to $1.09 per gallon assumed in the previous first quarter 2006 earnings guidance; and
  - Enogex's gathering and processing business is projecting approximately 260 new well connects in 2006.
- Marketing gross margin contribution of approximately $9 million remains unchanged;

- Operating and maintenance expenses increase approximately $7 million primarily due to increased employee and benefit costs;
- Interest expense remains relatively flat in 2006;

- Capital expenditures for investment in Enogex's pipeline system are approximately $70 to $80 million in 2006; and
- Funding for the Company's pension plan of $90 million in 2006, of which up to $7.4 million may be allocated to Enogex.

Enogex expects to continue to evaluate the strategic fit and financial performance of each of its assets in an effort to ensure a proper economic allocation of resources. The magnitude and timing of any potential impairment or gain on the disposition of any assets have not been included in the 2006 earnings guidance.

Holding Company

For 2006, the Company's earnings guidance for the holding company now reflects a lower expected loss of $4 million, or $0.04 per diluted share, from a loss of $5 million to $6 million, or $0.05 to $0.06 per diluted share. The change is the result of several factors or different assumptions, including:

- Decrease in effective tax rate at the holding company as a result of tax credits previously recorded at OG&E now being recorded at the holding company;
- Funding for the Company's pension plan of $90 million in 2006, of which approximately $12.7 million may be allocated to the holding company (which is ultimately allocated to OG&E and Enogex); and
- Interest expense decreases slightly in 2006 from 2005 due to lower levels of short-term debt offset by higher short-term interest rates.

Results of Operations

The following discussion and analysis presents factors that affected the Company's consolidated results of operations for the three and six months ended June 30, 2006 as compared to the same period in 2005 and the Company's consolidated financial position at June 30, 2006. 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 June 30,		**Six Months Ended June 30,**	
(In millions, except per share data)	**2006**	2005	**2006**	2005
Operating income	**$ 117.7**	$ 75.8	**$ 169.5**	$ 94.5
Net income	**$ 93.7**	$ 38.5	**$ 118.6**	$ 43.8
Basic average common shares outstanding	**90.9**	90.2	**90.8**	90.1
Diluted average common shares outstanding	**92.0**	90.8	**91.9**	90.6
Basic earnings per average common share	**$ 1.03**	$ 0.43	**$ 1.31**	$ 0.49
Diluted earnings per average common share	**$ 1.02**	$ 0.42	**$ 1.29**	$ 0.48
Dividends declared per share	**$ 0.3325**	$ 0.3325	**$ 0.6650**	$ 0.6650

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 unusual or infrequent items, the cost of capital and income taxes.

Operating Income (Loss) by Business Segment

	Three Months Ended June 30,		Six Months Ended June 30,	
(In millions)	**2006**	2005	**2006**	2005
OG&E (Electric Utility)	**$ 88.8**	$ 55.0	**$ 98.6**	$ 57.8
Enogex (Natural Gas Pipeline)	**29.6**	21.1	**71.7**	35.9
Other Operations (A)	**(0.7)**	(0.3)	**(0.8)**	0.8
Consolidated operating income	**$ 117.7**	$ 75.8	**$ 169.5**	$ 94.5

(A) Other Operations primarily includes unallocated corporate expenses and 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 June 30,		Six Months Ended June 30,	
(Dollars in millions)	**2006**	2005	**2006**	2005
Operating revenues	**$ 444.7**	$ 394.1	**$ 818.7**	$ 695.1
Cost of goods sold	**229.6**	215.9	**467.3**	390.9
Gross margin on revenues	**215.1**	178.2	**351.4**	304.2
Other operation and maintenance	**80.0**	79.7	**159.7**	157.1
Depreciation	**33.2**	31.4	**66.3**	64.5
Taxes other than income	**13.1**	12.1	**26.8**	24.8
Operating income	**88.8**	55.0	**98.6**	57.8
Other income	**0.6**	0.3	**0.8**	1.0
Other expense	**8.4**	0.3	**9.5**	0.8
Interest income	**0.4**	---	**1.4**	1.6
Interest expense	**11.5**	9.7	**25.2**	19.4
Income tax expense	**25.9**	15.6	**23.2**	12.2
Net income	**$ 44.0**	$ 29.7	**$ 42.9**	$ 28.0
Operating revenues by classification				
Residential	**$ 172.9**	$ 150.0	**$ 310.8**	$ 264.2
Commercial	**111.7**	101.4	**200.1**	171.6
Industrial	**90.3**	82.2	**175.7**	147.9
Public authorities	**43.9**	40.5	**81.0**	69.6
Sales for resale	**16.0**	13.7	**30.9**	26.8
Provision for refund on gas transportation and storage case	**---**	(1.1)	**---**	(2.1)
System sales revenues	**434.8**	386.7	**798.5**	678.0
Off-system sales revenues	**0.6**	0.9	**1.1**	1.3
Other	**9.3**	6.5	**19.1**	15.8
Total operating revenues	**$ 444.7**	$ 394.1	**$ 818.7**	$ 695.1
MWH (A) sales by classification (in millions)				
Residential	**2.0**	1.9	**3.9**	3.8
Commercial	**1.7**	1.5	**3.0**	2.8
Industrial	**1.8**	1.8	**3.5**	3.5
Public authorities	**0.8**	0.7	**1.4**	1.3
Sales for resale	**0.4**	0.4	**0.7**	0.7
System sales	**6.7**	6.3	**12.5**	12.1
Off-system sales	**---**	---	**---**	---
Total sales	**6.7**	6.3	**12.5**	12.1
Number of customers	**750,405**	739,983	**750,405**	739,983
Average cost of energy per KWH (B) - cents				
Fuel	**2.950**	2.864	**3.221**	2.644
Fuel and purchased power	**3.325**	3.216	**3.587**	3.023
Degree days (C)				
Heating				
Actual	**87**	202	**1,586**	1,867
Normal	**236**	236	**2,199**	2,199
Cooling				
Actual	**852**	644	**883**	645
Normal	**547**	547	**555**	555

(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 June 30, 2006 as compared to quarter ended June 30, 2005

OG&E's operating income increased approximately $33.8 million during the three months ended June 30, 2006 as compared to the same period in 2005 primarily due to higher gross margin partially offset by higher operating expenses.

Gross margin, which is operating revenues less cost of goods sold, was approximately $215.1 million during the three months ended June 30, 2006 as compared to approximately $178.2 million during the same period in 2005, an increase of approximately $36.9 million or 20.7 percent. The gross margin increased primarily due to:

- rate increases authorized in the OCC order in December 2005, which increased the gross margin by approximately $13.7 million;
- warmer weather in OG&E's service territory, which increased the gross margin by approximately $13.5 million;
- price variance due to sales and customer mix, which increased the gross margin by approximately $3.6 million;
- new customer growth in OG&E's service territory, which increased the gross margin by approximately $2.5 million; and
- increased peak demand by industrial customers in OG&E's service territory, which increased the gross margin by approximately $2.1 million.

Cost of goods sold for OG&E consists of fuel used in electric generation and purchased power. Fuel expense was approximately $175.3 million during the three months ended June 30, 2006 as compared to approximately $171.5 million during the same period in 2005, an increase of approximately $3.8 million or 2.2 percent due to a higher average cost of natural gas per kwh. Purchased power costs were approximately $54.3 million during the three months ended June 30, 2006 as compared to approximately $44.4 million during the same period in 2005, an increase of approximately $9.9 million or 22.3 percent primarily due to an increase in purchased power costs while various OG&E power plants were being overhauled.

Other operating and maintenance expenses were approximately $80.0 million during the three months ended June 30, 2006 as compared to approximately $79.7 million during the same period in 2005, an increase of approximately $0.3 million or 0.4 percent. The slight increase in other operating and maintenance expenses was primarily due to:

- higher salaries, wages, pension and other employee expenses of approximately $2.4 million;
- additional legal accrual for the settlement of a claim of approximately $2.2 million; and
- higher bad debt expense of approximately $1.4 million.

These increases in other operating and maintenance expenses were partially offset by:

- an increase in capitalized work of approximately $3.2 million; and
- a decrease in outside services of approximately $2.9 million.

The other operating and maintenance expense variance includes other operating and maintenance expenses associated with the acquisition of NRG McClain LLC's 77 percent interest in the 520 megawatt natural gas-fired combined cycle NRG McClain Station ("McClain Plant"), which expenses ceased being recorded as a regulatory asset on July 8, 2005.

Depreciation expense was approximately $33.2 million during the three months ended June 30, 2006 as compared to approximately $31.4 million during the same period in 2005, an increase of approximately $1.8 million or 5.7 percent. The increase was primarily due to a higher level of depreciable plant in addition to depreciation expense associated with the acquisition of the McClain Plant, which expenses ceased being recorded as a regulatory asset on July 8, 2005, partially offset by a decrease in depreciation rates that was implemented January 1, 2006.

Taxes other than income were approximately $13.1 million during the three months ended June 30, 2006 as compared to approximately $12.1 million during the same period in 2005, an increase of approximately $1.0 million or 8.3 percent, primarily due to increased ad valorem taxes. This variance includes ad valorem taxes associated with the acquisition of the McClain Plant, which expenses ceased being recorded as a regulatory asset on July 8, 2005.

Other income includes, among other things, contract work performed, non-operating rental income and miscellaneous non-operating income. Other income was approximately $0.6 million during the three months ended June 30,

2006 as compared to approximately $0.3 million during the same period in 2005, an increase of approximately $0.3 million or 100.0 percent. The increase in other income was primarily due to an increase in the allowance for equity funds used during construction of approximately $0.2 million.

Other expense includes, among other things, miscellaneous charitable donations, expenditures for certain civic, political and related activities and miscellaneous deductions and expenses. Other expense was approximately $8.4 million during the three months ended June 30, 2006 as compared to approximately $0.3 million during the same period in 2005, an increase of approximately $8.1 million. The increase in other expense was primarily due to:

- a loss on the retirement of fixed assets of approximately $6.8 million; and
- an increase in charitable donations of approximately $0.5 million due to the timing of the payment of the contributions.

Net interest expense includes interest income, interest expense and other interest charges. Net interest expense was approximately $11.1 million during the three months ended June 30, 2006 as compared to approximately $9.7 million during the same period in 2005, an increase of approximately $1.4 million or 14.4 percent. The increase in net interest expense was primarily due to:

- increased interest of approximately $2.7 million on debt associated with the McClain Plant acquisition, which OG&E ceased recording as a regulatory asset on July 8, 2005; and
- increased interest of approximately $0.6 million due to increased short-term borrowings.

These increases in net interest expense were partially offset by:

- a decrease in interest expense due to an increase in the allowance for borrowed funds used during construction of approximately $0.8 million.

Income tax expense was approximately $25.9 million during the three months ended June 30, 2006 as compared to approximately $15.6 million during the same period in 2005, an increase of approximately $10.3 million or 66.0 percent primarily due to higher pre-tax income for OG&E.

Six months ended June 30, 2006 as compared to six months ended June 30, 2005

OG&E's operating income increased approximately $40.8 million during the six months ended June 30, 2006 as compared to the same period in 2005 primarily due to higher gross margin partially offset by higher operating expenses.

Gross margin was approximately $351.4 million during the six months ended June 30, 2006 as compared to approximately $304.2 million during the same period in 2005, an increase of approximately $47.2 million or 15.5 percent. The gross margin increased primarily due to:

- rate increases authorized in the OCC order in December 2005, which increased the gross margin by approximately $23.2 million;
- warmer weather in OG&E's service territory, which increased the gross margin by approximately $7.8 million;
- price variance due to sales and customer mix, which increased the gross margin by approximately $6.7 million;
- new customer growth in OG&E's service territory, which increased the gross margin by approximately $4.8 million; and
- increased peak demand by industrial customers in OG&E's service territory, which increased the gross margin by approximately $3.7 million.

Fuel expense was approximately $360.0 million during the six months ended June 30, 2006 as compared to approximately $303.8 million during the same period in 2005, an increase of approximately $56.2 million or 18.5 percent due to a higher average cost of natural gas per kwh. Purchased power costs were approximately $107.3 million during the six months ended June 30, 2006 as compared to approximately $87.1 million during the same period in 2005, an increase of approximately $20.2 million or 23.2 percent primarily due to an increase in purchased power costs while various OG&E power plants were being overhauled.

Other operating and maintenance expenses were approximately $159.7 million during the six months ended June 30, 2006 as compared to approximately $157.1 million during the same period in 2005, an increase of approximately $2.6 million or 1.7 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher salaries, wages, pension and other employee expenses of approximately $7.7 million;
- higher allocations from the holding company of approximately $3.9 million primarily due to higher miscellaneous corporate expenses;
- additional legal accrual for the settlement of a claim of approximately $2.2 million; and
- higher bad debt expense of approximately $2.1 million.

These increases in other operating and maintenance expenses were partially offset by:

- an increase in capitalized work of approximately $10.7 million; and
- a decrease in outside services of approximately $5.1 million.

The other operating and maintenance expense variance includes other operating and maintenance expenses associated with the acquisition of the McClain Plant, which expenses ceased being recorded as a regulatory asset on July 8, 2005.

Depreciation expense was approximately $66.3 million during the six months ended June 30, 2006 as compared to approximately $64.5 million during the same period in 2005, an increase of approximately $1.8 million or 2.8 percent. The increase was primarily due to a higher level of depreciable plant in addition to depreciation expense associated with the acquisition of the McClain Plant, which expenses ceased being recorded as a regulatory asset on July 8, 2005, partially offset by a decrease in depreciation rates that was implemented January 1, 2006.

Taxes other than income were approximately $26.8 million during the six months ended June 30, 2006 as compared to approximately $24.8 million during the same period in 2005, an increase of approximately $2.0 million or 8.1 percent, primarily due to increased ad valorem taxes. This variance includes ad valorem taxes associated with the acquisition of the McClain Plant, which expenses ceased being recorded as a regulatory asset on July 8, 2005.

Other income was approximately $0.8 million during the six months ended June 30, 2006 as compared to approximately $1.0 million during the same period in 2005, a decrease of approximately $0.2 million or 20.0 percent. The decrease in other income was primarily due to approximately $0.2 million in the first quarter of 2005 from the sale of miscellaneous assets.

Other expense was approximately $9.5 million during the six months ended June 30, 2006 as compared to approximately $0.8 million during the same period in 2005, an increase of approximately $8.7 million. The increase in other expense was primarily due to:

- a loss on the retirement of fixed assets of approximately $6.8 million;
- an increase in charitable donations of approximately $0.5 million due to the timing of the payment of the contributions; and
- a write-down of natural gas inventory of approximately $0.4 million.

Net interest expense was approximately $23.8 million during the six months ended June 30, 2006 as compared to approximately $17.8 million during the same period in 2005, an increase of approximately $6.0 million or 33.7 percent. The increase in net interest expense was primarily due to:

- increased interest of approximately $5.3 million on debt associated with the McClain Plant acquisition, which OG&E ceased recording as a regulatory asset on July 8, 2005; and
- increased interest of approximately $1.5 million due to increased short-term borrowings.

These increases in net interest expense were partially offset by:

- a decrease in interest expense due to an increase in the allowance for borrowed funds used during construction of approximately $1.2 million.

Income tax expense was approximately $23.2 million during the six months ended June 30, 2006 as compared to approximately $12.2 million during the same period in 2005, an increase of approximately $11.0 million or 90.2 percent primarily due to higher pre-tax income for OG&E.

Enogex – Continuing Operations

(Dollars in millions)	Three Months Ended June 30, 2006	Three Months Ended June 30, 2005	Six Months Ended June 30, 2006	Six Months Ended June 30, 2005
Operating revenues	**$ 517.6**	$ 968.9	**$ 1,280.8**	$ 1,954.1
Cost of goods sold	**448.0**	911.0	**1,126.0**	1,844.6
Gross margin on revenues	**69.6**	57.9	**154.8**	109.5
Other operation and maintenance	**25.4**	22.8	**54.0**	45.3
Depreciation	**10.4**	10.0	**20.6**	20.0
Taxes other than income	**4.2**	4.0	**8.5**	8.3
Operating income	**29.6**	21.1	**71.7**	35.9
Other income	**0.2**	0.5	**6.2**	0.5
Other expense	**0.1**	0.1	**0.1**	0.1
Interest income	**3.3**	0.5	**5.8**	1.1
Interest expense	**7.9**	8.1	**16.0**	16.0
Income tax expense	**9.6**	5.3	**25.9**	8.3
Income from continuing operations	**$ 15.5**	$ 8.6	**$ 41.7**	$ 13.1
New well connects	**53**	65	**107**	113
Gathered volumes – TBtu/d (A)	**0.99**	0.89	**0.97**	0.89
Incremental transportation volumes – TBtu/d	**0.57**	0.38	**0.51**	0.35
Total throughput volumes – TBtu/d	**1.56**	1.27	**1.48**	1.24
Natural gas processed – TBtu/d	**0.53**	0.56	**0.53**	0.53
Natural gas liquids sold (keep-whole) – million gallons	**86**	84	**160**	162
Natural gas liquids sold (POL and fixed-fee) – million gallons	**3**	3	**6**	7
Total natural gas liquids sold – million gallons	**89**	87	**166**	169
Average sales price per gallon	**$ 0.895**	$ 0.750	**$ 0.903**	$ 0.748

(A) Trillion British thermal units per day.

Quarter ended June 30, 2006 as compared to quarter ended June 30, 2005

Enogex's operating income increased approximately $8.5 million during the three months ended June 30, 2006 as compared to the same period in 2005 primarily due to increased gross margins in each of Enogex's businesses largely as a result of a favorable commodity environment. The increases in gross margin were partially offset by higher operating and maintenance expenses.

Transportation and storage contributed approximately $27.2 million of Enogex's gross margin during the three months ended June 30, 2006 as compared to approximately $24.1 million during the same period in 2005, an increase of approximately $3.1 million or 12.9 percent. The gross margin increased primarily due to:

- better management of gas pipeline imbalances as Enogex reduced its exposure to gas imbalances while taking advantage of favorable market price movement in the second quarter of 2006, in addition to gas imbalance expense recognized by the gathering business in the second quarter of 2006, which imbalance obligations were carried by the transportation and storage business in 2005, which increased the gross margin by approximately $3.6 million;
- a change in Enogex's 2005 accounting estimate of the volume of natural gas in its natural gas storage inventory, which reduced the 2005 gross margin by approximately $3.4 million;
- increased commodity and interruptible revenues primarily due to higher volumes, which increased the gross margin by approximately $1.7 million; and
- increased natural gas sales due to higher realized natural gas prices in 2006 partially offset with a decrease in volumes, which increased the gross margin by approximately $1.7 million.

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

- increase in fuel over recovery reserve of approximately $5.1 million as a result of the Company transitioning to zone fuel rates in 2006 coupled with significant over recoveries in 2006 in the East zone; and
- a lower of cost or market adjustment as the June 30, 2006 market price for natural gas had fallen below the Company's carrying cost, related to storage of natural gas used to operate the pipeline in the second quarter of 2006, which reduced the 2006 gross margin by approximately $1.9 million as there was no comparable item during the three months ended June 30, 2005.

Gathering and processing contributed approximately $42.2 million of Enogex's gross margin during the three months ended June 30, 2006 as compared to approximately $34.3 million during the same period in 2005, an increase of approximately $7.9 million or 23.0 percent. The gathering and processing gross margin increased primarily due to:

- increased net keep-whole margins largely as a result of favorable commodity spreads, which

increased the gross margin by approximately $12.1 million; and
- contractual fuel gains primarily due to higher gathered volumes, which increased the gross margin by approximately $2.4 million.

These increases in the gathering and processing gross margin were partially offset by:

- the recognition of imbalance expense in the second quarter of 2006, which imbalance obligations were carried by the transportation and storage business in 2005, which reduced the gross margin by approximately $5.8 million.

Marketing contributed approximately $0.2 million of Enogex's gross margin during the three months ended June 30, 2006 as compared to a reduction in gross margin of approximately $0.5 million during the same period in 2005, an increase of approximately $0.7 million. The gross margin increased primarily due to:

- gains in storage activity, which increased the gross margin by approximately $2.2 million; and
- more favorable market conditions on transportation contracts, which increased the gross margin by approximately $0.3 million.

These increases in the marketing gross margin were partially offset by:

- a lower of cost or market adjustment related to natural gas in storage in the second quarter of 2006, which reduced the 2006 gross margin by approximately $1.6 million; and
- a decrease in the gross margin due to trading activity of approximately $0.3 million.

Enogex's other operating and maintenance expenses were approximately $25.4 million during the three months ended June 30, 2006 as compared to approximately $22.8 million during the same period in 2005, an increase of approximately $2.6 million or 11.4 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher salaries, wages, pension and other employee expenses of approximately $3.6 million; and
- higher uncollectible reserve of approximately $0.7 million.

These increases in other operating and maintenance expense were partially offset by a sales and use tax refund of approximately $2.0 million received in May 2006 related to activity in prior years.

Other income was approximately $0.2 million during the three months ended June 30, 2006 as compared to approximately $0.5 million during the same period in 2005, a decrease of approximately $0.3 million or 60.0 percent. The decrease was primarily due to a sales and use tax refund of approximately $0.4 million received in June 2005 related to activity in prior years.

Net interest expense was approximately $4.6 million during the three months ended June 30, 2006 as compared to approximately $7.6 million during the same period in 2005, a decrease of approximately $3.0 million or 39.5 percent. The decrease in net interest expense is primarily due to an increase in interest income on cash investments from interest earned on the cash proceeds from the sale of Enogex Arkansas Pipeline Corporation ("EAPC") in October 2005 and the sale of certain gas gathering assets in May 2006.

Income tax expense was approximately $9.6 million during the three months ended June 30, 2006 as compared to approximately $5.3 million during the same period in 2005, an increase of approximately $4.3 million or 81.1 percent primarily due to higher pre-tax income for Enogex.

For the three months ended June 30, 2006, Enogex's net income, including the discontinued operations discussed below under the caption "Enogex – Discontinued Operations," was approximately $51.3 million. During the three months ended June 30, 2006, Enogex had an increase in net income of approximately $37.1 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex's businesses. These increases in net income include:

- a gain of approximately $34.7 million related to the sale of certain gas gathering assets in Kinta, Oklahoma;
- a sales and use tax refund related to activity in prior years of approximately $1.3 million; and
- income from discontinued operations of approximately $1.1 million.

For the three months ended June 30, 2005, Enogex's net income, including the discontinued operations discussed below under the caption "Enogex – Discontinued Operations," was approximately $11.3 million. During the three months ended June 30, 2005, Enogex had an increase in net income of approximately $2.7 million that the Company does not consider to be reflective of the ongoing profitability of Enogex's business related to income from discontinued operations.

Six months ended June 30, 2006 as compared to six months ended June 30, 2005

Enogex's operating income increased approximately $35.8 million during the six months ended June 30, 2006 as compared to the same period in 2005 primarily due to increased gross margins in each of Enogex's businesses largely as a result of a favorable commodity environment. The increases in gross margin were partially offset by higher operating and maintenance expenses.

Transportation and storage contributed approximately $68.1 million of Enogex's gross margin during the six months ended June 30, 2006 as compared to approximately $48.1 million during the same period in 2005, an increase of approximately $20.0 million or 41.6 percent. The gross margin increased primarily due to:

- better management of gas pipeline imbalances as Enogex reduced its exposure to gas imbalances while taking advantage of favorable market price movement in 2006, in addition to gas imbalance expense recognized by the gathering business in 2006, which imbalance obligations were carried by the transportation and storage business in 2005, which increased the gross margin by approximately $9.4 million;
- improved recovery of fuel as Enogex experienced fuel under recoveries in 2005 and fuel over recoveries in 2006, which increased the gross margin by approximately $4.8 million;
- storage field hedging gains, which increased the gross margin by approximately $3.5 million;
- a change in Enogex's 2005 accounting estimate of the volume of natural gas in its natural gas storage inventory, which reduced the 2005 gross margin by approximately $3.4 million;
- increased commodity and interruptible revenues primarily due to higher volumes, which increased the gross margin by approximately $3.0 million; and
- increased natural gas sales as a result of an increase in gas sales margin due to higher realized natural gas prices in 2006, which increased the gross margin by approximately $2.2 million.

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

- increase in fuel over recovery reserve of approximately $5.1 million as a result of the Company transitioning to zone fuel rates in 2006 coupled with significant over recoveries in 2006 in the East zone; and
- a lower of cost or market adjustment as the June 30, 2006 market price for natural gas had fallen below the Company's carrying cost, related to storage of natural gas used to operate the pipeline during the first six months of 2006, which reduced the 2006 gross margin by approximately $1.9 million as there was no comparable item during the first six months of 2005.

Gathering and processing contributed approximately $80.4 million of Enogex's gross margin during the six months ended June 30, 2006 as compared to approximately $63.5 million during the same period in 2005, an increase of approximately $16.9 million or 26.6 percent. The gathering and processing gross margin increased primarily due to:

- increased net keep-whole margins primarily due to favorable commodity spreads, which increased the gross margin by approximately $17.0 million;
- contractual fuel gains primarily due to higher gathered volumes, which increased the gross margin by approximately $4.2 million;
- a reduction in the fuel recovery reserve liability, which had been recorded as a result of fuel over recoveries during the last six months of 2005, of approximately $2.9 million as compared to 2005 in which no reserve activity was recorded as the gathering business was in an under recovered position during the first six months of 2006;
- higher natural gas prices on natural gas sales reflective of opportunities in the marketplace, which increased the gross margin by approximately $2.0 million; and
- increased gross margin on the sale of fuel over recoveries of approximately $0.8 million.

These increases in the gathering and processing gross margin were partially offset by:

- the recognition of imbalance expense in 2006, which imbalance obligations were carried by the transportation and storage business in 2005, which reduced the gross margin by approximately $7.6 million; and
- an increase in revenues allocated to the transportation and storage business from the gathering business in 2006 partially offset by an increase in the gross margin related to higher gathered volumes, which reduced the gross margin by approximately $1.5 million.

Marketing contributed approximately $6.3 million of Enogex's gross margin during the six months ended June 30, 2006 as compared to a reduction in gross margin of approximately $2.1 million during the same period in 2005, an increase of approximately $8.4 million. The gross margin increased primarily due to:

- a correction to the accounting procedure for park and loan transactions (natural gas storage transactions) in the first quarter of 2005, which decreased the gross margin in the first quarter of

2005 by approximately $7.7 million (see Note 16 of Notes to Condensed Consolidated Financial Statements); and
- more favorable market conditions on transportation contracts, which increased the gross margin by approximately $7.0 million.

These increases in the marketing gross margin were partially offset by:

- a lower of cost or market adjustment as the June 30, 2006 market price for natural gas had fallen below the Company's carrying cost, related to natural gas in storage during the first six months of 2006, which reduced the 2006 gross margin by approximately $3.8 million; and
- less favorable market prices and opportunities in trading activity, which reduced the gross margin by approximately $2.8 million.

Enogex's other operating and maintenance expenses were approximately $54.0 million during the six months ended June 30, 2006 as compared to approximately $45.3 million during the same period in 2005, an increase of approximately $8.7 million or 19.2 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher salaries, wages, pension and other employee expenses of approximately $6.3 million;
- higher outside service costs of approximately $2.5 million primarily related to business development projects and work performed to maintain the integrity and safety of Enogex's pipeline;
- higher uncollectible reserve of approximately $0.9 million;
- higher materials and supplies costs of approximately $0.8 million primarily related to work performed to maintain the integrity and safety of Enogex's pipeline; and
- higher allocations from the holding company of approximately $0.4 million due to higher miscellaneous corporate expenses.

These increases in other operating and maintenance expense were partially offset by a sales and use tax refund of approximately $2.0 million received in May 2006 related to activity in prior years.

Other income was approximately $6.2 million during the six months ended June 30, 2006 as compared to approximately $0.5 million during the same period in 2005, an increase of approximately $5.7 million. The increase was primarily due to a litigation settlement of approximately $5.2 million (see Note 17 of Notes to Condensed Consolidated

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Financial Statements) and the gain on the sale of small gathering sections of Enogex's pipeline of approximately $0.5 million in the first quarter of 2006.

Net interest expense was approximately $10.2 million during the six months ended June 30, 2006 as compared to approximately $14.9 million during the same period in 2005, a decrease of approximately $4.7 million or 31.5 percent. The decrease in net interest expense is primarily due to an increase in interest income on cash investments from interest earned on the cash proceeds from the sale of EAPC in October 2005 and the sale of certain gas gathering assets in May 2006.

Income tax expense was approximately $25.9 million during the six months ended June 30, 2006 as compared to approximately $8.3 million during the same period in 2005, an increase of approximately $17.6 million primarily due to higher pre-tax income for Enogex.

For the six months ended June 30, 2006, Enogex's net income, including the discontinued operations discussed below under the caption "Enogex – Discontinued Operations," was approximately $78.3 million. During 2006, Enogex had an increase in net income of approximately $41.4 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex's business. These increases in net income include:

- income from discontinued operations of approximately $36.6 million;
- litigation settlement (see Note 17 of Notes to Condensed Consolidated Financial Statements) of approximately $3.2 million;
- a sales and use tax refund related to activity in prior years of approximately $1.3 million; and
- the sale of small gathering sections of Enogex's pipeline of approximately $0.3 million.

For the six months ended June 30, 2005, Enogex's net income, including the discontinued operations discussed below under the caption "Enogex – Discontinued Operations," was approximately $19.4 million. During 2005, Enogex had an increase in net income of approximately $1.6 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex's business. This increase in net income was due to income from discontinued operations of approximately $6.3 million partially offset by a correction recorded in 2005 to the accounting procedure for park and loan transactions in 2004 of approximately $4.7 million.

Enogex – Discontinued Operations

In April 2005, Enogex Compression Company, LLC ("Enogex Compression") received an unsolicited offer to buy its interest in Enerven Compression Services, LLC ("Enerven"), a joint venture focused on the rental of natural gas compression assets. After evaluating this offer, Enogex Compression sold its interest in Enerven for approximately $7.3 million in August 2005. Enogex Compression recognized an after tax gain of approximately $1.8 million related to the sale of this business.

Enogex regularly evaluates the long term stability, profitability and core competency of each of its businesses within the regulatory and market framework in which each business operates. Based on these evaluations, in September 2005, Enogex announced that it had entered into an agreement to sell its interest in EAPC, which held the NOARK Pipeline System Limited Partnership interest. This sale was completed on October 31, 2005. The Company received approximately $177.4 million in cash proceeds and recognized an after tax gain of approximately $36.7 million from the sale of this business in the fourth quarter of 2005. Enogex used approximately $31.9 million of the proceeds to repay principal and accrued interest on long-term debt and approximately $46.7 million to pay taxes associated with EAPC. The balance of the proceeds of approximately $98.8 million, following temporary use to fund current cash needs, is expected to be used to invest, over time, in strategic assets.

In March 2006, Enogex announced that its wholly-owned subsidiary, Gathering, had entered into an agreement to sell certain gas gathering assets in the Kinta, Oklahoma, area. The Gathering assets included in the transaction were approximately 568 miles of gas gathering pipeline and 22 compressor units with current volumes of approximately 145 million cubic feet per day, all in eastern Oklahoma. The sale price was approximately $93 million. This transaction closed on May 1, 2006 and Enogex recorded an after tax gain of approximately $34.7 million during the second quarter of 2006. The proceeds from the sale, following temporary use to fund current cash needs, are expected to be used to invest, over time, in strategic assets.

As a result of these sale transactions, Enogex Compression's interest in Enerven, Enogex's interest in EAPC and Gathering's sale of certain gas gathering assets in Kinta, Oklahoma, which were part of the Natural Gas Pipeline segment, have been reported as discontinued operations for the three and six months ended June 30, 2006 and 2005 in the Condensed

Consolidated Financial Statements. Enogex Compression's sale of its Enerven interest and Enogex's sale of its EAPC interest were completed during 2005 and, therefore, there are no results of operations for these transactions during the three or six months ended June 30, 2006. Results for the discontinued operations are summarized and discussed below.

	Three Months Ended June 30,		**Six Months Ended June 30,**	
(In millions)	**2006**	2005	**2006**	2005
Operating revenues	**$ 2.8**	$ 26.9	**$ 9.4**	$ 54.2
Cost of goods sold	**0.8**	17.2	**4.9**	32.9
Gross margin on revenues	**2.0**	9.7	**4.5**	21.3
Other operation and maintenance	**0.2**	2.1	**1.0**	4.2
Depreciation	**---**	1.7	**0.3**	3.4
Taxes other than income	**---**	0.4	**0.1**	0.8
Operating income	**1.8**	5.5	**3.1**	12.9
Other income	**57.0**	---	**57.0**	---
Other expense	**---**	---	**---**	0.4
Net interest expense	**---**	1.1	**---**	2.3
Income tax expense	**23.0**	1.7	**23.5**	3.9
Net income	**$ 35.8**	$ 2.7	**$ 36.6**	$ 6.3

Quarter ended June 30, 2006 as compared to quarter ended June 30, 2005

Gross margin decreased approximately $7.7 million or 79.4 percent during the three months ended June 30, 2006 as compared to the same period in 2005 primarily due to the sale of EAPC in October 2005 and a decrease in natural gas purchases and sales due to a decrease in natural gas transported.

Operating and maintenance expense decreased approximately $1.9 million or 90.5 percent during the three months ended June 30, 2006 as compared to the same period in 2005 primarily due to the sale of EAPC in October 2005.

Depreciation expense decreased approximately $1.7 million during the three months ended June 30, 2006 as compared to the same period in 2005 primarily due to the sale of EAPC in October 2005 and ceasing depreciation expense in January 2006 when the Kinta gathering assets were reported as a discontinued operation.

Other income increased approximately $57.0 million during the three months ended June 30, 2006 as compared to the same period in 2005 due to the sale of the Kinta gathering assets in May 2006.

Net interest expense decreased approximately $1.1 million during the three months ended June 30, 2006 as compared to the same period in 2005 primarily due to the sale of EAPC in October 2005 and the use of a portion of the sale proceeds to repay long-term debt.

Income tax expense increased approximately $21.3 million during the three months ended June 30, 2006 as compared to the same period in 2005 primarily due to the sale of the Kinta gathering assets in May 2006.

Six months ended June 30, 2006 as compared to six months ended June 30, 2005

Gross margin decreased approximately $16.8 million or 78.9 percent during the six months ended June 30, 2006 as compared to the same period in 2005 primarily due to the sale of EAPC in October 2005 and a decrease in natural gas purchases and sales due to a decrease in natural gas transported.

Operating and maintenance expense decreased approximately $3.2 million or 76.2 percent during the six months ended June 30, 2006 as compared to the same period in 2005 primarily due to the sale of EAPC in October 2005.

Depreciation expense decreased approximately $3.1 million or 91.2 percent during the six months ended June 30, 2006 as compared to the same period in 2005 primarily due to the sale of EAPC in October 2005 and ceasing depreciation expense in January 2006 when the Kinta gathering assets were reported as a discontinued operation.

Other income increased approximately $57.0 million during the six months ended June 30, 2006 as compared to the same period in 2005 due to the sale of the Kinta gathering assets in May 2006.

Net interest expense decreased approximately $2.3 million during the six months ended June 30, 2006 as compared to the same period in 2005 primarily due to the sale of EAPC in October 2005 and the use of a portion of the sale proceeds to repay long-term debt.

Income tax expense increased approximately $19.6 million during the six months ended June 30, 2006 as compared to the same period in 2005 primarily due to the sale of the Kinta gathering assets in May 2006.

Financial Condition

The balance of Accounts Receivable was approximately $433.4 million and $591.4 million at June 30, 2006 and December 31, 2005, respectively, a decrease of approximately $158.0 million or 26.7 percent primarily due to lower natural gas sales prices and volume activity by Enogex partially offset by an increase in OG&E's billings to its customers reflecting warmer weather in June 2006 as compared to December 2005.

The balance of Accrued Unbilled Revenues was approximately $62.8 million and $41.8 million at June 30, 2006 and December 31, 2005, respectively, an increase of approximately $21.0 million or 50.2 percent. The increase reflects higher seasonal electric rates and increased usage due to warmer weather during June 2006 as compared to December 2005.

The balance of Fuel Inventories was approximately $79.1 million and $63.6 million at June 30, 2006 and December 31, 2005, respectively, an increase of approximately $15.5 million or 24.4 percent. The increase was primarily due to an increase in storage injections from new contracts at Enogex and a replenishment of the level of coal inventory at OG&E as OG&E experienced lower levels of coal inventory related to the coal shipment disruption in late 2005. These increases were partially offset by a reduction in inventories due to lower natural gas prices in June 2006.

The balance of current Price Risk Management assets was approximately $43.6 million and $116.5 million at June 30, 2006 and December 31, 2005, respectively, a decrease of approximately $72.9 million or 62.6 percent. The decrease was primarily due to lower natural gas prices associated with OGE Energy Resources, Inc. ("OERI") short-term physical natural gas purchase transactions and associated financial contracts. A reduction in the volume of OERI's short-term physical natural gas activity and associated financial contracts outstanding at June 30, 2006 from December 31, 2005 also contributed to the decrease.

The balance of Gas Imbalance asset was approximately $16.2 million and $32.0 million at June 30, 2006 and December 31, 2005, respectively, a decrease of approximately $15.8 million or 49.4 percent. The Gas Imbalance asset is comprised of planned or managed imbalances related to OERI's business, referred to as park and loan transactions, and pipeline and natural gas liquids imbalances, which are operational imbalances. Park and loan transactions were approximately $1.0 million and $15.7 million at June 30, 2006 and December 31, 2005, respectively, a decrease of approximately $14.7 million or 93.6 percent due to the expiration of 2005 park and loan transactions in OERI's business activities. Operational imbalances were approximately $15.2 million and $16.3

million at June 30, 2006 and December 31, 2005, respectively, a decrease of approximately $1.1 million or 6.7 percent primarily due to lower pricing.

The balance of Fuel Clause Over Recoveries was approximately $36.6 million (net of Fuel Clause Under Recoveries) at June 30, 2006. The balance of Fuel Clause Under Recoveries was approximately $101.1 million at December 31, 2005. The increase in fuel clause over recoveries was due to the amount billed to OG&E's customers during the six months ended June 30, 2006 exceeding OG&E's cost of fuel primarily due to lower natural gas prices. OG&E's fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result, OG&E under recovers fuel cost in periods of rising prices above the baseline charge for fuel and over recovers fuel cost when prices decline below the baseline charge for fuel. Provisions in the fuel clauses are intended to allow OG&E to amortize under or over recovery. OG&E remains under recovered in Arkansas but is over recovered in Oklahoma.

The balance of Construction Work in Progress was approximately $196.5 million and $101.8 million at June 30, 2006 and December 31, 2005, respectively, an increase of approximately $94.7 million or 93.0 percent. The increase was primarily due to construction expenditures related to OG&E's wind power project in addition to construction expenditures related to the expansion of Enogex's gathering pipeline capacity on the west side of its system.

The balance of Prepaid Benefit Obligation was approximately $133.5 million and $90.2 million at June 30, 2006 and December 31, 2005, respectively, an increase of approximately $43.3 million or 48.0 percent. The increase was primarily due to pension plan contributions during the second quarter.

The balance of Short-Term Debt was approximately $58.2 million and $30.0 million at June 30, 2006 and December 31, 2005, respectively, an increase of $28.2 million or 94.0 percent. The increase was primarily due to expenditures associated with the construction of the wind power project.

The balance of Accounts Payable was approximately $243.7 million and $510.4 million at June 30, 2006 and December 31, 2005, respectively, a decrease of approximately $266.7 million or 52.3 percent. The decrease was primarily due to lower natural gas purchases in June 2006 as compared to December 2005, less purchased power and timing of outstanding checks clearing the bank.

The balance of current Price Risk Management liabilities was approximately $37.8 million and $109.5 million at June 30, 2006 and December 31, 2005, respectively, a decrease of approximately $71.7 million or 65.5 percent. The decrease was primarily due to lower natural gas prices associated with OERI's short-term physical natural gas purchase transactions and associated financial contracts. A reduction in the volume of OERI's short-term physical natural gas activity and associated financial contracts outstanding at June 30, 2006 from December 31, 2005 also contributed to the decrease.

The balance of Gas Imbalance liability was approximately $21.8 million and $36.0 million at June 30, 2006 and December 31, 2005, respectively, a decrease of approximately $14.2 million or 39.4 percent. The Gas Imbalance liability is comprised of planned or managed imbalances related to OERI's business, referred to as park and loan transactions, and pipeline and natural gas liquids imbalances, which are operational imbalances. Park and loan transactions were approximately $3.0 million and $10.2 million at June 30, 2006 and December 31, 2005, respectively, a decrease of approximately $7.2 million or 70.6 percent due to the expiration of 2005 park and loan transactions in OERI's business activities. Operational imbalances were approximately $18.8 million and $25.8 million at June 30, 2006 and December 31, 2005, respectively, a decrease of approximately $7.0 million or 27.1 percent primarily due to lower pricing.

Off-Balance Sheet Arrangements

There have been no significant changes in the Company's off-balance sheet arrangements.

Liquidity and Capital Requirements

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

Future Capital Requirements

Capital Expenditures

As previously disclosed in the Company's Form 10-K for the year ended December 31, 2005, the Company's 2006, 2007 and 2008 capital expenditures were estimated at approximately: $307 million, $248 million and $250 million, respectively. The Company's current estimate for 2006 capital expenditures is approximately

$528 million, which includes capital expenditures of up to $205 million associated with OG&E's wind power project. OG&E received approval for the wind power project by the OCC on April 28, 2006 and expects to fund the wind power project with a capital contribution from the holding company and the issuance of long-term debt by OG&E in either the third or fourth quarter of 2006. The Company's current estimate for 2007 and 2008 capital expenditures is approximately $280 million in each year. These capital expenditures do not include capital expenditures related to the construction of a proposed power plant with PSO and the OMPA.

Other Regulatory Matters

Later in 2006, OG&E is planning to issue a request for proposal for additional capacity in 2008. In addition, OG&E is working with PSO and the OMPA to construct a new 950 MW coal unit to help meet its additional capacity needs in 2011 or 2012.

Pension and Postretirement Benefit Plans

The Company previously disclosed in its Form 10-K for the year ended December 31, 2005 that it may contribute up to $90 million to its pension plan during 2006. In the second quarter of 2006, the Company contributed approximately $60.0 million to the pension plan and currently expects to contribute an additional $30.0 million to the pension plan during the remainder of 2006. Any expected contributions to the pension plan during 2006 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.

In accordance with SFAS No. 88, "Employer's Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," a one-time settlement charge is required to be recorded by an organization when lump sum payments or other settlements that relieve the organization from the responsibility for the pension benefit obligation during a plan year exceed the service cost and interest cost components of the organization's net periodic pension cost. During the first six months of 2006 as compared to the first six months of recent years, the Company experienced an increase in both the number of employees electing to retire and the amount of lump sum payments to be paid to such employees upon retirement in 2006. As a result and based in part on the Company's historical experience regarding eligible employees who elect to retire in the second half of a particular year, the Company currently estimates that it could be required to take a pension settlement charge for 2006 and that the amount of the charge could be between $15 million and $26 million. Whether the Company will be required to take a pension settlement charge for 2006 will depend on numerous factors, including the amount of lump sum payments owed to employees who elect to retire during the balance of 2006 and the investment performance of the Company's pension plan during 2006. A pension settlement charge, if incurred, would not require a cash outlay by the Company and would not increase the Company's total pension expense over time, as the charge would be an acceleration of costs that otherwise would be recognized as pension expense in future periods.

Future Sources of Financing

Management expects that internally generated funds, long and short-term debt, proceeds from the sales of common stock pursuant to the Company's Automatic Dividend Reinvestment and Stock Purchase Plan and proceeds from dividends and stock sales 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.

Short-Term Debt

See Note 14 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 affect on the Company's Condensed Consolidated Financial Statements particularly as they relate to pension expense and impairment estimates. 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, accrued removal obligations, regulatory assets and liabilities, unbilled revenue for OG&E, operating revenues for Enogex, natural gas purchases for Enogex, the allowance for uncollectible accounts receivable, the valuation of energy purchase and sale contracts and fair value and cash flow hedges. The selection, application and disclosure of these 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 Form 10-K for the year ended December 31, 2005.

Accounting Pronouncements

See Notes 2 and 3 of Notes to Condensed Consolidated Financial Statements for a discussion of recent accounting pronouncements that are applicable to the Company.

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 have been postponed for the time being, 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 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. These developments at the federal and state levels are described in more detail in Notes 17 and 18 of Notes to Condensed Consolidated Financial Statements in this Form 10-Q and in the Company's Form 10-K for the year ended December 31, 2005. 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. In a citywide election in May 2006, Oklahoma City voters approved a 25-year franchise for OG&E which is the largest city in OG&E's service territory.

Commitments and Contingencies

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. 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 disclosed otherwise in this Form 10-Q and in the Company's Form 10-K for the year ended December 31, 2005 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 17 and 18 of Notes to Condensed Consolidated Financial Statements and Item 1 of Part II in this Form 10-Q and Notes 14 and 15 of Notes to the Company's Consolidated Financial Statements included in the Company's Form 10-K for the year ended December 31, 2005 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 Form 10-K for the year ended December 31, 2005 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 of $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 for the Company's trading activities, assuming a one day time horizon and 95 percent confidence level, 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 commodity by valuing each net position at quoted market prices. 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 as of June 30, 2006.

(In millions)	Trading
Commodity market risk, net	$ 0.2

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 received by the Company 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 operating income of the Company. 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 forecast prices. 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 as of June 30, 2006.

(In millions)	Non-Trading
Commodity market risk, net	$ 9.6

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 rules and forms. In addition, the disclosure controls and procedures are designed to 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 disclosures. 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, 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 Form 10-K for the year ended December 31, 2005 and to Part II, Item 1 of the Company's Form 10-Q for the quarter ended March 31, 2006 for a description of certain legal proceedings presently pending. Except as set forth below and in Notes 17 and 18 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.

Farris Buser Litigation

On July 22, 2005, Enogex along with certain other unaffiliated co-defendants was served with a purported class action which had been filed on February 7, 2005 by Farris Buser and other named plaintiffs in the District Court of Canadian County, Oklahoma. The plaintiffs' own royalty interests in certain oil and gas producing properties and allege they have been under-compensated by the named defendants, including the Enogex companies, relating to the sale of liquid hydrocarbons recovered during the transportation of natural gas from the plaintiffs' wells. The plaintiffs' assert breach of contract, implied covenants, obligation, fiduciary duty, unjust enrichment, conspiracy and fraud causes of action and claim actual damages in excess of $10,000, plus attorneys' fees and costs, and punitive damages in excess of $10,000. The Enogex companies filed a motion to dismiss which was granted on November 18, 2005, subject to the plaintiffs' right to conduct discovery and the possible re-filing of their allegations in the petition against Enogex companies. On September 19, 2005, the co-defendants, BP America, Inc. and BP America Production Co., filed a cross claim against Enogex Products Corporation ("Products") seeking indemnification and/or contribution from Products based upon the 1997 sale of a third party interest in one of Products natural gas processing plants. The court-established date for the refiling of the allegations in the petition was extended until May 17, 2006, and, on such date, the plaintiffs filed an amended petition against the Enogex companies. Enogex expects to file a motion to dismiss the amended petition on August 2, 2006. Based on its investigation to date, the Company believes these claims and cross claims in this lawsuit are without merit and intends to vigorously defend this case.

G.M. Oil Properties Litigation

On March 8, 2005, Enogex was served with a putative class action filed by G.M. Oil Properties, Inc. in the District Court of Comanche County, Oklahoma. The petition alleges that Enogex exercises a monopoly power with respect to its gathering facilities within the state of Oklahoma. The petition further alleges that, due to the alleged monopoly power, Enogex has caused damage to the plaintiff and other small gas producers and marketers. A settlement of this case was reached with the named plaintiffs and the case brought by the named plaintiffs was dismissed with prejudice. Pursuant to the settlement, a certain segment of gathering pipeline was sold to G.M. Oil Properties with the Company recognizing a loss of less than $0.1 million. This case is now closed.

Osterhout Litigation

On June 19, 2006, two OG&E customers brought a putative class action, on behalf of all similarly situated customers, in the District Court of Creek County, Oklahoma, challenging certain charges on OG&E's electric bills. The plaintiffs claim that OG&E improperly charged sales tax based on franchise fee charges paid by its customers. The plaintiffs also challenge certain franchise fee charges, contending that such fees are more than is allowed under Oklahoma law. At the present time, OG&E believes that this case is without merit and intends to vigorously defend this case.

Item 1A. Risk Factors.

There have been no significant changes in the Company's risk factors as discussed in the Company's Form 10-K for the year ended December 31, 2005.

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
4/1/06 – 4/30/06	49,500	$29.41	N/A	N/A
5/1/06 – 5/31/06	---	---	N/A	N/A
6/1/06 – 6/30/06	---	---	N/A	N/A

N/A – not applicable

Item 4. Submission of Matters to a Vote of Security Holders.

(a) The Company's Annual Meeting of Shareowners was held on May 18, 2006.

(b) Not applicable.

(c) The matters voted upon and the results of the voting at the Annual Meeting were as follows:

(1) The Shareowners voted to elect the Company's nominees for election to the Board of Directors as follows:

John D. Groendyke – 81,907,124 votes for election and 1,276,299 votes withheld

Robert O. Lorenz – 80,738,096 votes for election and 2,445,327 votes withheld

Steven E. Moore – 81,470,808 votes for election and 1,712,615 votes withheld

(2) The Shareowners voted to ratify the appointment of Ernst & Young LLP as the Company's principal independent accountants for 2006 with 82,013,602 votes for election, 513,600 votes against and 656,218 votes abstained.

(d) Not applicable.

Item 6. Exhibits.

Exhibit No.	Description
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

August 2, 2006

Exhibit 31.01

CERTIFICATIONS

I, Steven E. Moore, certify that:

1. I have reviewed this quarterly report on Form 10-Q of OGE Energy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 2, 2006

/s/ Steven E. Moore
Steven E. Moore
Chairman of the Board, President and
Chief Executive Officer

Exhibit 31.01

CERTIFICATIONS

I, James R. Hatfield, certify that:

1. I have reviewed this quarterly report on Form 10-Q of OGE Energy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting.

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: August 2, 2006

/s/ James R. Hatfield
James R. Hatfield
Senior Vice President and
Chief Financial Officer

Exhibit 32.01

Certification Pursuant to 18 U.S.C. Section 1350
As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Quarterly Report of OGE Energy Corp. (the "Company") on Form 10-Q for the period ended June 30, 2006, as filed with the Securities and Exchange Commission (the "Report"), each of the undersigned does hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

August 2, 2006

/s/ Steven E. Moore
Steven E. Moore
Chairman of the Board, President
and Chief Executive Officer

/s/ James R. Hatfield
James R. Hatfield
Senior Vice President and
Chief Financial Officer