OGE ENERGY CORP
Form 10-Q
November 01, 2006

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

FORM 10-Q

(Mark One)

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF

THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended September 30, 2006

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF

THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____to_____

Commission File Number: 1-12579

OGE ENERGY CORP.

(Exact name of registrant as specified in its charter)

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

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

405-553-3000
(Registrant s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer 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 o Non-Accelerated Filer o

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

Yes o No x

As of September 30, 2006, 91,139,901 shares of common stock, par value $0.01 per share, were outstanding.

OGE ENERGY CORP.

FORM 10-Q

FOR THE QUARTER ENDED SEPTEMBER 30, 2006

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Item 1. Financial Statements.

OGE ENERGY CORP.

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(In millions)	**September 30, 2006**	December 31, 2005
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 0.6**	$ 26.4
Deposit with Internal Revenue Service	**32.0**	---
Accounts receivable, less reserve of $4.1 and $3.7, respectively	**449.4**	591.4
Accrued unbilled revenues	**45.5**	41.8
Fuel inventories	**64.2**	63.6
Materials and supplies, at average cost	**56.9**	56.5
Price risk management	**73.6**	116.5
Gas imbalances	**12.0**	32.0
Accumulated deferred tax assets	**12.2**	14.3
Fuel clause under recoveries	**---**	101.1
Recoverable take or pay gas charges	**---**	4.9
Prepayments and other	**24.9**	25.1
Total current assets	**771.3**	1,073.6
OTHER PROPERTY AND INVESTMENTS, at cost	**31.4**	29.2
PROPERTY, PLANT AND EQUIPMENT		
In service	**6,161.6**	5,999.4
Construction work in progress	**199.8**	101.8
Total property, plant and equipment	**6,361.4**	6,101.2
Less accumulated depreciation	**2,609.7**	2,568.7
Net property, plant and equipment	**3,751.7**	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	**3,751.7**	3,567.4
DEFERRED CHARGES AND OTHER ASSETS		
Income taxes recoverable from customers, net	**32.1**	32.8
Intangible asset - unamortized prior service cost	**32.8**	32.8
Prepaid benefit obligation	**155.2**	90.2
Price risk management	**1.8**	9.0
McClain Plant deferred expenses	**20.2**	24.9

Unamortized loss on reacquired debt	**20.4**	21.3
Unamortized debt issuance costs	**9.3**	8.1
Other	**6.9**	7.2
Deferred charges and other assets of discontinued operations	**---**	2.4
Total deferred charges and other assets	**278.7**	228.7
TOTAL ASSETS	**$ 4,833.1**	$ 4,898.9

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

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OGE ENERGY CORP.

CONDENSED CONSOLIDATED BALANCE SHEETS (Continued)

(Unaudited)

(In millions)	**September 30, 2006**	December 31, 2005
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 38.8**	$ 30.0
Accounts payable	**251.0**	510.4
Dividends payable	**30.3**	30.1
Customers deposits	**50.8**	47.8
Accrued taxes	**97.8**	67.1
Accrued interest	**23.0**	31.9
Tax collections payable	**11.4**	8.7
Accrued compensation	**35.2**	40.3
Long-term debt due within one year	**128.0**	---
Price risk management	**39.1**	109.5
Gas imbalances	**13.0**	36.0
Fuel clause over recoveries	**39.8**	---
Provision for payments of take or pay gas	**---**	8.9
Other	**26.8**	29.9
Total current liabilities	**785.0**	950.6
LONG-TERM DEBT	**1,221.5**	1,350.8
COMMITMENTS AND CONTINGENCIES (NOTE 16)		
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued pension and benefit obligations	**250.2**	234.5
Accumulated deferred income taxes	**846.9**	807.1
Accumulated deferred investment tax credits	**28.0**	31.7
Accrued removal obligations, net	**124.0**	114.3
Price risk management	**0.8**	10.7
Asset retirement obligation	**3.7**	3.6
Other	**27.6**	19.8
Total deferred credits and other liabilities	**1,281.2**	1,221.7
STOCKHOLDERS EQUITY		
Common stockholders equity	**734.8**	715.5
Retained earnings	**899.8**	750.5
Accumulated other comprehensive loss, net of tax	**(89.2)**	(90.2)
Total stockholders equity	**1,545.4**	1,375.8
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	**$ 4,833.1**	$ 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 September 30,		**Nine Months Ended September 30,**	
(In millions, except per share data)	**2006**	2005	**2006**	2005
OPERATING REVENUES				
Electric Utility operating revenues	**$ 608.7**	$ 612.9	**$ 1,427.4**	$ 1,308.0
Natural Gas Pipeline operating revenues	**521.9**	1,061.2	**1,747.3**	2,961.7
Total operating revenues	**1,130.6**	1,674.1	**3,174.7**	4,269.7
COST OF GOODS SOLD (exclusive of depreciation shown below)				
Electric Utility cost of goods sold	**281.8**	316.3	**725.3**	683.5
Natural Gas Pipeline cost of goods sold	**467.3**	1,012.5	**1,562.5**	2,826.3
Total cost of goods sold	**749.1**	1,328.8	**2,287.8**	3,509.8
Gross margin on revenues	**381.5**	345.3	**886.9**	759.9
Other operation and maintenance	**98.1**	92.8	**306.6**	289.3
Depreciation	**44.9**	46.5	**135.3**	135.0
Impairment of assets	**0.3**	---	**0.3**	---
Taxes other than income	**17.6**	17.1	**54.6**	52.1
OPERATING INCOME	**220.6**	188.9	**390.1**	283.5
OTHER INCOME (EXPENSE)				
Allowance for equity funds used during construction	**2.3**	---	**2.5**	---
Other income	**0.4**	0.2	**7.9**	2.8
Other expense	**(2.3)**	(1.5)	**(12.4)**	(4.2)
Net other income (expense)	**0.4**	(1.3)	**(2.0)**	(1.4)
INTEREST INCOME (EXPENSE)				
Interest income	**1.5**	0.3	**4.6**	2.4
Interest on long-term debt	**(21.8)**	(21.8)	**(65.3)**	(60.5)
Allowance for borrowed funds used during construction	**1.3**	0.4	**3.8**	1.7
Interest on short-term debt and other interest charges	**(9.2)**	(5.3)	**(11.1)**	(8.6)
Net interest expense	**(28.2)**	(26.4)	**(68.0)**	(65.0)
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	**192.8**	161.2	**320.1**	217.1
INCOME TAX EXPENSE	**70.8**	54.8	**116.1**	73.2
INCOME FROM CONTINUING OPERATIONS	**122.0**	106.4	**204.0**	143.9
DISCONTINUED OPERATIONS				
Income (loss) from discontinued operations	**(1.0)**	7.1	**59.1**	17.3
Income tax expense (benefit)	**(0.4)**	2.4	**23.1**	6.3
Income (loss) from discontinued operations	**(0.6)**	4.7	**36.0**	11.0
NET INCOME	**$ 121.4**	$ 111.1	**$ 240.0**	$ 154.9
BASIC AVERAGE COMMON SHARES OUTSTANDING	**91.1**	90.4	**90.9**	90.2
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**92.4**	90.8	**92.0**	90.6
BASIC EARNINGS (LOSS) PER AVERAGE COMMON SHARE				
Income from continuing operations	**$ 1.34**	$ 1.18	**$ 2.24**	$ 1.60
Income (loss) from discontinued operations, net of tax	**(0.01)**	0.05	**0.40**	0.12
NET INCOME	**$ 1.33**	$ 1.23	**$ 2.64**	$ 1.72
DILUTED EARNINGS (LOSS) PER AVERAGE COMMON SHARE				
Income from continuing operations	**$ 1.32**	$ 1.17	**$ 2.22**	$ 1.59
Income (loss) from discontinued operations, net of tax	**(0.01)**	0.05	**0.39**	0.12
NET INCOME	**$ 1.31**	$ 1.22	**$ 2.61**	$ 1.71
DIVIDENDS DECLARED PER SHARE	**$ 0.3325**	$ 0.3325	**$ 0.9975**	$ 0.9975

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

OGE ENERGY CORP.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Nine Months Ended September 30,	
(In millions)	**2006**	2005
CASH FLOWS FROM OPERATING ACTIVITIES		
Income from continuing operations	**$ 204.0**	$ 143.9
Adjustments to reconcile income from continuing operations to net cash provided from operating activities		
Depreciation	**135.3**	135.0
Impairment of assets	**0.3**	---
Deferred income taxes and investment tax credits, net	**25.7**	31.0
Allowance for equity funds used during construction	**(2.5)**	---
Gain on sale of assets	**(0.6)**	(0.2)
Loss on retirement of fixed assets	**6.1**	---
Stock-based compensation expense	**2.9**	---
Excess tax benefit on stock-based compensation	**(1.4)**	---
Price risk management assets	**50.1**	(248.5)
Price risk management liabilities	**(79.8)**	203.5
Other assets	**(65.7)**	(15.0)
Other liabilities	**26.2**	(10.8)
Change in certain current assets and liabilities		
Deposit with Internal Revenue Service	**(32.0)**	---
Accounts receivable, net	**220.4**	(130.5)
Accrued unbilled revenues	**(3.7)**	(18.3)
Fuel, materials and supplies inventories	**(1.2)**	8.2
Gas imbalance asset	**20.0**	9.7
Fuel clause under recoveries	**101.1**	(28.2)
Other current assets	**5.1**	(4.7)
Accounts payable	**(259.4)**	28.9
Customers deposits	**3.0**	1.3
Accrued taxes	**32.6**	57.2
Accrued interest	**(8.9)**	(6.1)
Gas imbalance liability	**(23.0)**	10.9
Fuel clause over recoveries	**39.8**	---
Other current liabilities	**(11.0)**	13.7
Net Cash Provided from Operating Activities	**383.4**	181.0
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	**(334.8)**	(208.4)
Proceeds from sale of assets	**1.9**	1.4
Net Cash Used in Investing Activities	**(332.9)**	(207.0)
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	**(211.2)**	113.5
Issuance of common stock	**10.3**	14.6
Excess tax benefit on stock-based compensation	**1.4**	---
Dividends paid on common stock	**(90.5)**	(89.9)
Net Cash (Used in) Provided from Financing Activities	**(72.5)**	3.9

DISCONTINUED OPERATIONS				
Net cash (used in) provided from operating activities	**(3.6)**		3.7	
Net cash (used in) provided from investing activities	**(0.2)**		6.1	
Net cash provided from financing activities	**---**		1.3	
Net Cash (Used in) Provided from Discontinued Operations	**(3.8)**		11.1	
NET DECREASE IN CASH AND CASH EQUIVALENTS	**(25.8)**		(11.0)	
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**26.4**		11.1	
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$**	**0.6**	$	0.1

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

OGE ENERGY CORP.

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Summary of Significant Accounting Policies

Organization

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. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail gas business in 1928 and is no longer engaged in the gas distribution business.

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, which have been reported as discontinued operations in the Company s Condensed Consolidated Financial Statements (see Note 7 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 September 30, 2006 and December 31, 2005, the results of its operations for the three and nine months ended September 30, 2006 and 2005, and the results of its cash flows for the nine months ended September 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 nine months ended September 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)	**September 30, 2006**	December 31, 2005
Regulatory Assets		
Income taxes recoverable from customers, net	**$ 32.1**	$ 32.8
Unamortized loss on reacquired debt	**20.4**	21.3
McClain Plant deferred expenses	**20.2**	24.9
Cogeneration credit rider under recovery	**5.7**	3.7
Fuel clause under recoveries	**---**	101.1
Recoverable take or pay gas charges	**---**	4.9
Miscellaneous	**0.7**	0.5
Total Regulatory Assets	**$ 79.1**	$ 189.2
Regulatory Liabilities		
Accrued removal obligations, net	**$ 124.0**	$ 114.3
Fuel clause over recoveries	**39.8**	---
Deferred gain on sale of assets	**2.9**	3.8
Miscellaneous	**0.3**	---
Total Regulatory Liabilities	**$ 167.0**	$ 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 nine months ended September 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 nine months ended September 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 September 30, 2005	Nine Months Ended September 30, 2005
Net income, as reported	$ 111.1	$ 154.9
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	0.1	0.4
Pro forma net income	$ 111.0	$ 154.5
Income per average common share		
Basic as reported	$ 1.23	$ 1.72
Diluted as reported	$ 1.22	$ 1.71
Basic pro forma	$ 1.23	$ 1.71
Diluted pro forma	$ 1.22	$ 1.71

Reclassifications

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

2. Accounting Pronouncements

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.

In September 2006, the FASB issued SFAS No. 157, Fair Value Measurements, which defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 expands disclosures about the use of fair value to measure assets and liabilities in interim and annual periods subsequent to initial recognition. The guidance in SFAS No. 157 applies to derivatives and other financial instruments measured at fair value under SFAS No. 133, Accounting for Derivative Instruments and Hedging Activities, at initial recognition and in all subsequent periods. Therefore, SFAS No. 157 nullifies the guidance in footnote 3 of Emerging Issues Task Force Issue No. 02-3, Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities. SFAS No. 157 also amends SFAS No. 133 to remove the guidance similar to that nullified in EITF 02-3. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after

November 15, 2007, and interim periods within those fiscal years. The provisions of SFAS No. 157 should be applied prospectively as of the beginning of the fiscal year in which it is initially applied, except in certain conditions. The Company will adopt this new standard effective January 1, 2008. Management has not yet determined what the impact of this new standard will be on its consolidated financial position or results of operations.

In September 2006, the FASB issued SFAS No. 158, Employers Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132R. SFAS No. 158 requires an employer to: (i) recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity; and (ii) to measure the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. The requirement to initially recognize the funded status of the defined benefit postretirement plan and the disclosure requirements are effective for the year ended December 31, 2006 for the Company. The requirement to measure plan assets and benefit obligations as of the date of the employer s fiscal year-end statement of financial position is effective for fiscal years ending after December 15, 2008. The Company will adopt provision (i) above of this new standard effective December 31, 2006. At December 31, 2005, the projected benefit obligation of the Company s pension plan and restoration of retirement income plan was approximately $594.0 million, while the fair value of assets in the pension plan and restoration of retirement income plan was approximately $439.4 million. Also, at December 31, 2005, the projected benefit obligation of the Company s postretirement benefit plans was approximately $208.2 million, while the fair value of assets in the postretirement benefit plans was approximately $67.2 million. These amounts will be revised based on a review of the funded status of the Company s pension and postretirement benefit plans by the Company s actuarial consultants as of December 31, 2006. The Company will adopt provision (ii) above of this new standard effective December 31, 2008, which is not expected to have a material impact on its consolidated financial position or results of operations as this provision supports the Company s historical measurement of the funded status of its pension and postretirement benefit plans.

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 a reduction in compensation expense of approximately $1.4 million pre-tax ($0.8 million after tax) and $0.5 million pre-tax ($0.3 million after tax) during the three and nine months ended September 30, 2005, respectively, due to a decrease in the total shareholder return (TSR) ranking relative to a peer group of companies for its performance units. No stock-based employee compensation expense related to stock options was recognized for the three and nine months ended September 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 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, which is not included in the amounts discussed below. 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 $1.6 million pre-tax ($1.0 million after tax, or $0.01 per basic and diluted share) and $6.0 million pre-tax ($3.7 million after tax, or $0.04 per basic and diluted share) during the three and nine months ended September 30, 2006, respectively, 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 No. 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 of approximately $0.7 million and $1.8 million during the three and nine months ended September 30, 2006, respectively, related to the Company s 2006 share-based payments. The Company realized an excess tax benefit of approximately $1.4 million during each of the three and nine month periods ended September 30, 2006, related to the

Company s 2005 share-based payments, which amount was presented as a financing cash inflow and realized when the Company s 2005 income tax return was filed in August 2006.

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 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

The Company recorded compensation expense of approximately $1.2 million pre-tax ($0.7 million after tax) and $4.3 million pre-tax ($2.6 million after tax) during the three and nine months ended September 30, 2006, respectively, related to the performance units based on TSR. The Company recorded a reduction in compensation expense of approximately $2.0 million pre-tax ($1.2 million after tax) and $1.1 million pre-tax ($0.7 million after tax) during the three and nine months ended September 30, 2005, respectively, due to a decrease in the TSR ranking relative to a peer group of companies for the 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 September 30, 2006 based on the following assumptions.

	2005	2004
Expected dividend yield	4.4%	4.4%
Expected price volatility	15.8%	15.8%
Risk-free interest rate	4.91%	5.02%
Expected life of units (in years)	1.25	0.25
Fair value of units at 9/30/06	$ 50.23	$ 57.77

A summary of the activity for the Company s performance units based on TSR at September 30, 2006 and changes during the nine months ended September 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	(8,337)	1 : 1	
Units Outstanding at 9/30/06	445,848	1 : 1	$ 29.7

(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 September 30, 2006 and changes during the nine months ended September 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 (C)	179,892	$ 22.93
Forfeited	(8,337)	$ 21.91
Units Non-Vested at 9/30/06 (D)	445,848	$ 21.67

(C) 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.

(D) Of the 445,848 performance units not vested at September 30, 2006, 399,022 performance units are assumed to vest at the end of the vesting period.

At September 30, 2006, there was approximately $4.4 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 1.73 years.

Performance Units Earnings Per Share

The Company recorded compensation expense of approximately $0.4 million pre-tax ($0.3 million after tax) and $1.5 million pre-tax ($0.9 million after tax) during the three and nine months ended September 30, 2006, respectively, related to the performance units based on EPS. The Company recorded compensation expense of approximately $0.6 million pre-tax ($0.4 million after tax) during each of the three and nine month periods ended September 30, 2005 related to performance units based on EPS. 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 September 30, 2006 and changes during the nine months ended September 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	(2,243)	1:1	
Units Outstanding at 9/30/06	104,260	1:1	$ 7.5

(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 September 30, 2006 and changes during the nine months ended September 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 (C)	59,964	$ 28.00
Forfeited	(2,243)	$ 26.21
Units Non-Vested at 9/30/06 (D)	104,260	$ 26.15

(C) 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.

(D) Of the 104,260 performance units not vested at September 30, 2006, 89,218 performance units are assumed to vest at the end of the vesting period.

At September 30, 2006, there was approximately $3.0 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 1.93 years.

Stock Options

The Company recorded compensation expense of less than $0.1 million pre-tax during each of the three and nine month periods ended September 30, 2006 related to the stock options. During the first nine 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 September 30, 2006 and changes during the nine months ended September 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	(466,207)	$ 22.05	$ 4.8	
Expired	(15,200)	$ 26.58		
Forfeited	(1,467)	$ 23.58		
Options Outstanding at 9/30/06	1,656,502	$ 22.20	$ 23.0	5.06 years
Options Fully Vested and Exercisable at 9/30/06	1,561,519	$ 22.11	$ 21.9	4.95 years

A summary of the activity for the Company s non-vested options at September 30, 2006 and changes during the nine months ended September 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	(307,948)	$ 1.91
Forfeited	(1,467)	$ 2.05
Options Non-Vested at 9/30/06 (A)	94,983	$ 2.05

(A) Of the 94,983 stock options not vested at September 30, 2006, 92,564 stock options are assumed to vest at the end of the vesting period.

At September 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 0.25 years.

The Company issues new shares to satisfy stock option exercises. The Company received approximately $4.2 million and $10.3 million, respectively, during the three and nine months ended September 30, 2006 related to exercised stock options. The Company recorded an excess tax benefit of approximately $0.7 million and $1.8 million during the three and nine months ended September 30, 2006, respectively, related to the Company s 2006 share-based payments. The Company realized an excess tax benefit of approximately $1.4 million during each of the three and nine month periods ended September 30, 2006, related to the Company s 2005 share-based payments, which amount was presented as a financing cash inflow and realized when the Company s 2005 income tax return was filed in August 2006.

4. Loss on Retirement and Asset Retirement Obligation 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 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 was approximately $6.8 million, which was recorded as a pre-tax loss during the second quarter of 2006. This loss was included in Other Expense in the Condensed Consolidated Statement of Income. Also, as part of the settlement of the asset retirement obligation (ARO) for these turbines, OG&E recorded a reduction to the previously recorded ARO for these turbines of approximately $0.7 million during the third quarter of 2006 due to an agreement with a third party to provide removal and remediation services. This reduction is included in Other Expense in the Condensed Consolidated Statement of Income.

5. 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 September 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 $70.1 million and $34.6 million at September 30, 2006, respectively, and would be approximately $98.0 million and $92.8 million at December 31, 2005, respectively.

6. Accumulated Other Comprehensive Loss

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

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(In millions)	**2006**	2005	**2006**	2005
Net income	**$ 121.4**	$ 111.1	**$ 240.0**	$ 154.9
Other comprehensive income (loss), net of tax:				
Deferred hedging gains (losses), net of tax	**5.4**	(5.4)	**0.8**	(5.5)
Amortization of cash flow hedge, net of tax	**0.1**	0.1	**0.2**	0.2
Total comprehensive income	**$ 126.9**	$ 105.8	**$ 241.0**	$ 149.6

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

(In millions)	**September 30, 2006**	December 31, 2005
Minimum pension liability adjustment, net of tax	**$ (91.1)**	$ (91.1)
Deferred hedging gains, net of tax	**3.9**	3.1
Settlement and amortization of cash flow hedge, net of tax	**(2.0)**	(2.2)
Total accumulated other comprehensive loss	**$ (89.2)**	$ (90.2)

Accumulated other comprehensive loss at both September 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 in the fourth quarter of 2006.

7. 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 $34.1 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 nine months ended September 30, 2006. Summarized financial information for the discontinued operations as of September 30 is as follows:

CONDENSED CONSOLIDATED STATEMENTS OF INCOME DATA

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(In millions)	**2006**	2005	**2006**	2005
Operating revenues from discontinued operations	**$ ---**	$ 29.5	**$ 9.4**	$ 83.7
Income (loss) from discontinued operations before taxes	**$ (1.0)**	$ 7.1	**$ 59.1**	$ 17.3

CONDENSED CONSOLIDATED BALANCE SHEET DATA

(In millions)	**September 30, 2006**	December 31, 2005
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

8. 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.

	Nine Months Ended September 30,	
(In millions)	**2006**	2005
NON-CASH INVESTING AND FINANCING ACTIVITIES		
Change in fair value of long-term debt due to interest rate swaps	**$ ---**	$ (4.3)

9. 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 September 30,		**Nine Months Ended September 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	**2.5**	(0.2)	**2.7**	0.7
Tax credits, net	**(0.6)**	(0.8)	**(1.2)**	(1.8)
ESOP dividends	**(0.6)**	(1.9)	**(0.8)**	(1.6)
Medicare Part D subsidy	**(1.0)**	---	**(0.7)**	---
Amortization of net unfunded deferred taxes	**1.8**	2.1	**1.6**	1.8
Other	**(0.4)**	(0.2)	**(0.3)**	(0.4)
Effective income tax rate as reported	**36.7%**	34.0%	**36.3%**	33.7%

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 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 Income Tax 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. On August 17, 2006, the Company made a deposit with the IRS in anticipation that a portion of prior year deductions will be disallowed. The deposit enabled OG&E to cease accruing interest effective August 17, 2006. The impact of this matter on future 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 nine months of 2006, OG&E recorded approximately $3.5 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 Condensed Consolidated Statements of Income.

10. Common Stock

For the three and nine months ended September 30, 2006, respectively, there were 167,732 shares and 569,660 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.

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11. Earnings Per Share

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	**2006**	2005	**2006**	2005
Average Common Shares Outstanding				
Basic average common shares outstanding	**91.1**	90.4	**90.9**	90.2
Effect of dilutive securities:				
Employee stock options and unvested stock grants	**0.4**	0.3	**0.3**	0.3
Contingently issuable shares (performance units)	**0.9**	0.1	**0.8**	0.1
Diluted average common shares outstanding	**92.4**	90.8	**92.0**	90.6

For the three and nine months ended September 30, 2006, respectively, there were no shares and approximately 0.3 million shares related to outstanding employee stock options, which 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. For the three and nine months ended September 30, 2005, respectively, there were no shares and approximately 0.2 million shares related to outstanding employee stock options, which 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.

12. Long-Term Debt

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

Long-Term Debt with Optional Redemption Provisions

OG&E s $125.0 million principal amount 6.65 percent Senior Notes (Senior Notes) due July 15, 2027, are repayable on July 15, 2007, at the option of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to July 15, 2007. Only holders who submit requests for repayment between May 15, 2007 and June 15, 2007 are entitled to such repayments. In accordance with SFAS No. 6, Classification of Short-Term Obligations Expected to Be Refinanced, OG&E reclassified the Senior Notes from long-term debt to long-term debt due within one year at September 30, 2006 due to the one-time put option of the Senior Notes. However, based on where the Senior Notes have recently traded, OG&E does not believe it is probable that this option will be exercised by the note holders.

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.

13. Short-Term Debt

The short-term debt balance was approximately $38.8 million and $30.0 million at September 30, 2006 and December 31, 2005, respectively, an increase of approximately $8.8 million or 29.3 percent. In the fourth quarter of 2005, $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 accordance with SFAS No. 6, 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 September 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	0.6	N/A	N/A	N/A
Total	$ 750.6	$ ---	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 $

(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 n

(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 n

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.

14. 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	**Nine Months Ended**

	September 30,		**September 30,**	
(In millions)	**2006**	2005	**2006**	2005
Service cost	**$ 5.1**	$ 4.8	**$ 15.3**	$ 14.3
Interest cost	**7.6**	7.6	**23.0**	22.8
Return on plan assets	**(9.6)**	(8.5)	**(28.7)**	(25.6)
Amortization of net loss	**4.2**	3.6	**12.5**	11.0
Amortization of unrecognized prior service cost	**1.5**	1.6	**4.4**	4.7
Net periodic benefit cost	**$ 8.8**	$ 9.1	**$ 26.5**	$ 27.2

	Postretirement Benefit Plans			
	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(In millions)	**2006**	2005	**2006**	2005
Service cost	**$ 1.0**	$ 0.8	**$ 2.8**	$ 2.4
Interest cost	**2.9**	2.6	**8.9**	7.8
Return on plan assets	**(1.4)**	(1.3)	**(4.2)**	(4.1)
Amortization of transition obligation	**0.7**	0.7	**2.1**	2.1
Amortization of net loss	**2.2**	1.2	**6.5**	3.8
Amortization of unrecognized prior service cost	**0.5**	0.5	**1.5**	1.5
Net periodic benefit cost	**$ 5.9**	$ 4.5	**$ 17.6**	$ 13.5

Pension Plan Funding

In the second quarter of 2006, the Company contributed approximately $60.0 million to the pension plan and contributed an additional $30.0 million to the pension plan during the third quarter of 2006. The contributions to the pension plan, in the form of cash, were discretionary contributions and were not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended.

15. 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 nine months ended September 30, 2006 and for the three and nine months ended September 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 nine months ended September 30, 2006 and 2005.

Three Months Ended September 30, 2006 *(In millions)*	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
Operating revenues	**$ 608.7**	**$ 557.2**	**$ ---**	**$ (35.3)**	**$ 1,130.6**
Cost of goods sold	**293.6**	**490.4**	**---**	**(34.9)**	**749.1**
Gross margin on revenues	**315.1**	**66.8**	**---**	**(0.4)**	**381.5**
Other operation and maintenance	**74.1**	**26.3**	**(2.3)**	**---**	**98.1**
Depreciation	**32.5**	**10.6**	**1.8**	**---**	**44.9**
Impairment of assets	**---**	**0.3**	**---**	**---**	**0.3**
Taxes other than income	**13.0**	**4.1**	**0.5**	**---**	**17.6**
Operating income	**195.5**	**25.5**	**---**	**(0.4)**	**220.6**
Allowance for equity funds used during construction	**2.3**	**---**	**---**	**---**	**2.3**
Other income	**0.2**	**0.2**	**---**	**---**	**0.4**
Other expense	**0.3**	**0.1**	**1.9**	**---**	**2.3**
Interest income	**0.3**	**2.9**	**0.8**	**(2.5)**	**1.5**
Interest expense	**21.0**	**7.8**	**3.4**	**(2.5)**	**29.7**
Income tax expense (benefit)	**69.6**	**8.0**	**(6.6)**	**(0.2)**	**70.8**
Income from continuing operations	**$ 107.4**	**$ 12.7**	**$ 2.1**	**$ (0.2)**	**$ 122.0**
Income (loss) from discontinued operations	**$ ---**	**$ (0.6)**	**$ ---**	**$ ---**	**$ (0.6)**
Net income	**$ 107.4**	**$ 12.1**	**$ 2.1**	**$ (0.2)**	**$ 121.4**
Total assets	**$ 3,454.5**	**$ 1,341.3**	**$ 1,984.5**	**$ (1,947.2)**	**$ 4,833.1**

(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 September 30, 2006 *(In millions)*	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
Operating revenues	**$ 48.4**	**$ 194.2**	**$ 433.7**	**$ (119.1)**	**$ 557.2**
Operating income (loss)	**$ 8.4**	**$ 19.2**	**$ (2.1)**	**$ ---**	**$ 25.5**

Three Months Ended September 30, 2005 *(In millions)*	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
Operating revenues	$ 612.9	$ 1,108.3	$ ---	$ (47.1)	$ 1,674.1
Cost of goods sold	328.3	1,047.5	---	(47.0)	1,328.8
Gross margin on revenues	284.6	60.8	---	(0.1)	345.3
Other operation and maintenance	73.0	22.4	(2.6)	---	92.8
Depreciation	34.7	9.8	2.0	---	46.5
Taxes other than income	12.9	3.6	0.6	---	17.1
Operating income	164.0	25.0	---	(0.1)	188.9
Other income (loss)	(0.3)	0.2	0.3	---	0.2
Other expense	0.8	---	0.7	---	1.5
Interest income	0.3	0.3	0.2	(0.5)	0.3
Interest expense	15.1	8.3	3.8	(0.5)	26.7
Income tax expense (benefit)	48.7	6.9	(0.7)	(0.1)	54.8
Income (loss) from continuing operations	$ 99.4	$ 10.3	$ (3.3)	$ ---	$ 106.4
Income from discontinued operations	$ ---	$ 4.7	$ ---	$ ---	$ 4.7
Net income (loss)	$ 99.4	$ 15.0	$ (3.3)	$ ---	$ 111.1
Total assets	$ 3,279.8	$ 1,966.4	$ 1,887.4	$ (1,827.4)	$ 5,306.2

(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 September 30, 2005 *(In millions)*	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
Operating revenues	$ 68.7	$ 156.2	$ 1,021.5	$ (138.1)	$ 1,108.3
Operating income (loss)	$ 13.6	$ 20.0	$ (8.6)	$ ---	$ 25.0

Nine Months Ended September 30, 2006 *(In millions)*	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
Operating revenues	**$ 1,427.4**	**$ 1,838.0**	**$ ---**	**$ (90.7)**	**$ 3,174.7**
Cost of goods sold	**760.9**	**1,616.4**	**---**	**(89.5)**	**2,287.8**
Gross margin on revenues	**666.5**	**221.6**	**---**	**(1.2)**	**886.9**
Other operation and maintenance	**233.8**	**80.3**	**(7.5)**	**---**	**306.6**
Depreciation	**98.8**	**31.2**	**5.3**	**---**	**135.3**
Impairment of assets	**---**	**0.3**	**---**	**---**	**0.3**
Taxes other than income	**39.8**	**12.6**	**2.2**	**---**	**54.6**
Operating income	**294.1**	**97.2**	**---**	**(1.2)**	**390.1**
Allowance for equity funds used during construction	**2.5**	**---**	**---**	**---**	**2.5**
Other income	**---**	**6.4**	**1.5**	**---**	**7.9**
Other expense	**9.0**	**0.2**	**3.2**	**---**	**12.4**
Interest income	**1.7**	**8.7**	**3.1**	**(8.9)**	**4.6**
Interest expense	**46.2**	**23.8**	**11.5**	**(8.9)**	**72.6**
Income tax expense (benefit)	**92.8**	**33.9**	**(10.1)**	**(0.5)**	**116.1**
Income from continuing operations	**$ 150.3**	**$ 54.4**	**$ ---**	**$ (0.7)**	**$ 204.0**
Income from discontinued operations	**$ ---**	**$ 36.0**	**$ ---**	**$ ---**	**$ 36.0**
Net income	**$ 150.3**	**$ 90.4**	**$ ---**	**$ (0.7)**	**$ 240.0**
Total assets	**$ 3,454.5**	**$ 1,341.3**	**$ 1,984.5**	**$ (1,947.2)**	**$ 4,833.1**

(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.

Nine Months Ended September 30, 2006 *(In millions)*	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
Operating revenues	**$ 176.1**	**$ 520.7**	**$ 1,530.8**	**$ (389.6)**	**$ 1,838.0**
Operating income (loss)	**$ 41.7**	**$ 56.6**	**$ (1.1)**	**$ ---**	**$ 97.2**

Nine Months Ended September 30, 2005 *(In millions)*	Electric Utility (A)	Natural Gas Pipeline (B)	Other Operations	Intersegment	Total
Operating revenues	$ 1,308.0	$ 3,062.4	$ ---	$ (100.7)	$ 4,269.7
Cost of goods sold	719.2	2,892.1	---	(101.5)	3,509.8
Gross margin on revenues	588.8	170.3	---	0.8	759.9
Other operation and maintenance	230.1	67.7	(8.5)	---	289.3
Depreciation	99.2	29.8	6.0	---	135.0
Taxes other than income	37.7	11.9	2.5	---	52.1
Operating income	221.8	60.9	---	0.8	283.5
Other income	0.7	0.7	1.4	---	2.8
Other expense	1.6	0.1	2.5	---	4.2
Interest income	1.9	1.4	0.7	(1.6)	2.4
Interest expense	34.5	24.4	10.1	(1.6)	67.4
Income tax expense (benefit)	60.9	15.2	(3.2)	0.3	73.2
Income (loss) from continuing operations	$ 127.4	$ 23.3	$ (7.3)	$ 0.5	$ 143.9
Income from discontinued operations	$ ---	$ 11.0	$ ---	$ ---	$ 11.0
Net income (loss)	$ 127.4	$ 34.3	$ (7.3)	$ 0.5	$ 154.9
Total assets	$ 3,279.8	$ 1,966.4	$ 1,887.4	$ (1,827.4)	$ 5,306.2

(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.

Nine Months Ended September 30, 2005 *(In millions)*	Transportation and Storage	Gathering and Processing	Marketing (C)	Eliminations	Total
Operating revenues	$ 181.4	$ 452.3	$ 2,812.2	$ (383.5)	$ 3,062.4
Operating income (loss)	$ 31.9	$ 44.0	$ (15.0)	$ ---	$ 60.9

(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 September 30, 2005.

16. Commitments and Contingencies

Except as set forth below and in Note 17, 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

The Company s current estimate for 2006 capital expenditures is approximately $535 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 early 2007. The Company s current estimate for 2007 and 2008 capital expenditures is approximately $415 million and $420 million, respectively. These capital expenditures do not include capital expenditures related to environmental expenditures for regional haze as discussed below or capital expenditures related to the construction of a proposed power plant as discussed in Note 17.

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, which is included in Other Income in the Condensed Consolidated Statement of Income. The Company now considers these matters closed.

Natural Gas Measurement Case

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, the Company has been involved in legal proceedings with Jack J. Grynberg related to the improper or intentional measurement of gas. On October 20, 2006, the District Court of Wyoming ruled on Grynberg s appeal, following and confirming the recommendation of the special master as it relates to Enogex Inc., Enogex Services Corp., Transok, Inc. and OG&E, dismissing all claims for lack of subject matter jurisdiction. The time for appeal for the October 20, 2006 order has not yet run.

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.

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 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 filed a motion to dismiss the amended petition on August 2, 2006. The hearing on the dismissal motion is expected to be scheduled in the fourth quarter of 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 the 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, along with the proposed mercury allowance allocations, into the state implementation 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 the monitoring equipment is estimated at approximately $7.0 million which is expected to be incurred during the years 2007 and 2008. 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 indicated 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 is being performed with a projected completion date of December 2006. Any proposed reductions or controls must be submitted to the ODEQ by March 2007. OG&E will have five years from the date the EPA approves the compliance plan 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-approval plan to handle state and federally mandated environmental upgrades which will be recoverable in Oklahoma from OG&E s retail customers under House Bill 1910, which was enacted into law in May 2005.

Currently, the EPA has designated Oklahoma in attainment with the ambient standard for ozone. However, elevated readings in the summer of 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. This compact expires in December 2007. However, the EPA has proposed continuation through a similar program called Ozone Flex, which both Oklahoma City and Tulsa expect to participate. 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 17 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.

17. 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 before the OCC (the 2002 Settlement Agreement) to acquire electric generation of not less than 400 MW s.

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

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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. 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 (January 1, 2004 through December 31, 2006), 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 subsequent to the end of the 36-month period. 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 Enogex system. By order dated April 13, 2006, the FERC approved and accepted Enogex s November 15, 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 proposed revised zonal fuel percentages based upon the actual zonal fuel usage from January 1, 2006 through April 30, 2006, rather than continuing with the estimated zonal percentages that were initially filed on November 15, 2005. Interventions and protests with respect to the revised fuel percentages were due on or before July 21, 2006. Six parties intervened but there were no protests. By order dated August 24, 2006, the FERC accepted Enogex s revised fuel percentages effective August 1, 2006. Enogex will file its annual fuel percentages for the 2007 fuel year (to become effective January 1, 2007) on or before November 15, 2006.

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 2002 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 September 30, 2006 and 2005, OG&E paid Enogex approximately $11.9 million and $12.0 million, respectively, for gas transportation and storage services. During the nine months ended September 30, 2006 and 2005, OG&E paid Enogex approximately $35.6 million and $35.7 million, respectively, 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 $1.1 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 obligation was fully refunded at September 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 and began charging OG&E s Oklahoma customers approximately $2.4 million annually. The OCC authorized tariff provides that the security rider may be updated quarterly. In compliance with the OCC order, in October 2006, OG&E filed a report regarding the recovery of the security costs through the authorized recovery rider for the period from July 1, 2006 to September 30, 2006. OG&E also expects to file an application with the OCC in November 2006 to amend its security plan to seek approval of approximately $7.5 million of cost overruns in previous authorized projects and approximately $12.7 million for new security projects. The annual revenue requirement associated with the $20.2 million of capital expenditures is approximately $2.8 million.

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; and (iv) establish a process in accordance with House Bill 1910 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 proposed 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 be 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 providing 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. During the nine months ended September 30, 2006, OG&E recorded approximately $0.8 million in SO2 sales proceeds from sales in 2006 that are included as an increase in Operating Revenues in the Condensed Consolidated Statement of Income. There were no SO2 sales during the three months ended September 30, 2006.

Review of OG&E s Fuel Adjustment Clause for Calendar Years 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 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. Oklahoma Industrial Energy Consumers, AES, Redbud and PowerSmith Cogeneration Project, L.P intervened in this proceeding. On September 21, 2006, OG&E reached a settlement with the other parties in this case that required no refunds. On October 16, 2006, the OCC issued an order that approved the settlement concluding that OG&E s 2003 fuel costs were prudent and OG&E s 2004 fuel costs were appropriately calculated.

Pending Regulatory Matters

OG&E Wind Power Filing

On February 20, 2006, OG&E entered into an agreement to engineer, procure and construct a wind generation energy system for a 120 MW wind farm planned for construction in northwestern Oklahoma. The agreement was subject to a number of conditions, all of which have subsequently been satisfied. Invenergy Wind Development Oklahoma LLC (Invenergy LLC) is to 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. The new wind farm is expected to be constructed and producing power on or about December 31, 2006. On April 6, 2006, a settlement agreement was filed with the OCC that, among other things, requested approval of the wind power 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 that 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 28, 2006, the OCC issued a unanimous order approving the settlement agreement. 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 approximately $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 general rate case that was filed on July 28, 2006. On September 11, 2006, OG&E energized the substation and generation tie line to connect the wind farm to OG&E s transmission system. The balance of work contractor has begun work on the actual construction of the wind farm itself, with a targeted in-service date of December 31, 2006 for the wind turbine generators.

OG&E Arkansas Rate Case Filing

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. On October 19, 2006, the APSC Staff filed responsive testimony that recommended that OG&E be authorized a rate increase of approximately $5.7 million while the Attorney General s office recommended a rate increase of approximately $6.4 million. However, the Attorney General s consultant also stated that additional disallowances are likely and reasonable, based on further investigation and information brought forward by the APSC Staff and other parties. Hearings in the rate case are scheduled to begin December 19, 2006. A decision by the APSC on the rate case application should occur no later than 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 subsidiary, Public Service Company of Oklahoma (PSO), and the Oklahoma Municipal Power Authority (OMPA) to build a new 950 MW coal unit at OG&E s existing Sooner plant location near Red Rock, Oklahoma. The estimated $1.8 billion project is the result of PSO s December 2005 request for proposals 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. 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 42 percent of the project. PSO will own 50 percent and the OMPA will own eight percent. OG&E expects to sign a construction ownership and operating agreement in the near future and expects construction to begin in 2007. Completion of the power plant is targeted by the summer of 2011. OG&E expects to file an application with the OCC later in the fourth quarter of 2006 stating that its portion of the construction costs are prudent and that a recovery mechanism should be established to recover its construction costs during the construction period. The OCC would be expected to issue an order addressing OG&E s pre-approval case prior to August 2007. The project is contingent upon numerous factors, including the successful completion of contract negotiations 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.

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.

Southwest Power Pool

The SPP filed on June 15, 2005, Docket No. ER05-1118, to create a real-time, offer-based imbalance energy market that 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 that 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 submitted 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 that 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. On October 24, 2006, the SPP Board of Directors reconsidered the overall readiness to implement the imbalance energy market on December 1, 2006. The SPP Board of Directors voted to delay implementation to no earlier than February 1, 2007. On October 25, 2006, the SPP notified the FERC of this delay. The SPP plans to prepare a certification of readiness to the FERC on or before January 1, 2007. 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 May 13, 2004, the FERC directed all utilities with pending three year market-based reviews to revise the generation market power portion of their three year review to address the new interim tests. OG&E and OERI submitted a compliance filing to the FERC on February 7, 2005 that applied the interim tests to OG&E and OERI. In the compliance filing, OG&E and OERI passed the pivotal supplier screen but did not pass the market share screen in 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.

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. 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 and August 25, 2006, pursuant to a FERC March 20, 2006 order, OG&E and OERI filed revisions to their market-based rate tariffs to allow them to sell energy imbalance service into the wholesale markets administered by the SPP at market-based rates.

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 and implementing regulations and policies mandated by the new energy act, some of which could have significance for electric utilities such as OG&E.

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.

18. 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.

	September 30, 2006		December 31, 2005	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
(In millions)				

Price Risk Management Assets				
Energy Trading Contracts	**$ 75.4**	**$ 75.4**	$ 125.4	$ 125.4
Price Risk Management Liabilities				
Energy Trading Contracts	**$ 39.9**	**$ 39.9**	$ 120.1	$ 120.1
Long-Term Debt				
Senior Notes	**$ 807.1**	**$ 830.8**	$ 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 5 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. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail gas business in 1928 and is no longer engaged in the gas distribution business.

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, which have been reported as discontinued operations in the Company s Condensed Consolidated Financial Statements (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 2006 Outlook and 2007 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 , objecti 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;

timing of the completion of OG&E s wind power project;

federal or state legislation and regulatory decisions (including OG&E s pending rate case before the APSC, the approval of future regulatory filings with the OCC related to its proposed construction of a new power plant and the outcome of OG&E s current FERC audit) and initiatives that affect cost and investment recovery, have an impact on rate structures or affect the speed and degree to which competition enters the Company s markets;

environmental laws and regulations that may impact the Company s operations;

changes in accounting standards, rules or guidelines;

the discontinuance of regulated accounting principles under SFAS No. 71;

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 September 30, 2006 as compared to quarter ended September 30, 2005

The Company reported net income of approximately $121.4 million, or $1.31 per diluted share, as compared to approximately $111.1 million, or $1.22 per diluted share, for the three months ended September 30, 2006 and 2005, respectively. The increase in net income during the three months ended September 30, 2006 as compared to the same period in 2005 was primarily due to:

- OG&E reported net income of approximately $107.4 million, or $1.16 per diluted share of the Company s common stock, as compared to approximately $99.4 million, or $1.09 per diluted share, during the three months ended September 30, 2006 and 2005, respectively;
- Enogex s operations, including discontinued operations, reported net income of approximately $12.1 million, or $0.13 per diluted share of the Company s common stock (of which a loss of $0.01 per diluted share was attributable to discontinued operations), as compared to approximately $15.0 million, or $0.17 per diluted share (of which $0.05 per diluted share was attributable to discontinued operations), during the three months ended September 30, 2006 and 2005, respectively; and
- net income at the holding company of approximately $1.9 million, or $0.02 per diluted share, during the three months ended September 30, 2006 as compared to a net loss of approximately $3.3 million, or $0.04 per diluted share, during the three months ended September 30, 2005 primarily due to a higher income tax benefit in 2006 as a result of recording the Employee Stock Ownership Plan (ESOP) dividend deduction at the holding company in 2006 which was previously recorded at OG&E in 2005.

Nine months ended September 30, 2006 as compared to nine months ended September 30, 2005

The Company reported net income of approximately $240.0 million, or $2.61 per diluted share, as compared to approximately $154.9 million, or $1.71 per diluted share, for the nine months ended September 30, 2006 and 2005, respectively. The increase in net income during the nine months ended September 30, 2006 as compared to the same period in 2005 was primarily due to:

- OG&E reported net income of approximately $150.3 million, or $1.63 per diluted share of the Company s common stock, as compared to approximately $127.4 million, or $1.41 per diluted share, during the nine months ended September 30, 2006 and 2005, respectively;
- Enogex s operations, including discontinued operations, reported net income of approximately $90.4 million, or $0.98 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 $34.3 million, or $0.38 per diluted share (of which $0.12 per diluted share was attributable to discontinued operations), during the nine months ended September 30, 2006 and 2005, respectively; and
- a net loss at the holding company of approximately $0.7 million, or less than $0.01 per diluted share, as compared to a net loss of approximately $6.8 million, or $0.08 per diluted share, during the nine months ended September 30, 2006 and 2005, respectively, primarily due to a higher income tax benefit in 2006 as a result of recording the ESOP dividend deduction at the holding company in 2006 which was previously recorded at OG&E in 2005.

Regulatory Matters

OG&E Wind Power Filing

On February 20, 2006, OG&E entered into an agreement to engineer, procure and construct a wind generation energy system for a 120 megawatt (MW) wind farm planned for construction in northwestern Oklahoma. 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. Construction of the wind farm has begun with a targeted in-service date of December 31, 2006 for the wind turbine generators. On April 28, 2006, the OCC approved a settlement agreement approving the wind power 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 that 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 general rate case that was filed on July 28, 2006.

OG&E Arkansas Rate Case Filing

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, its 77 percent interest in the 520 MW McClain Station (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. On October 19, 2006, the APSC Staff filed responsive testimony that recommended that OG&E be authorized a rate increase of approximately $5.7 million while the Attorney General s office recommended a rate increase of approximately $6.4 million. However, the Attorney General s consultant also stated that additional disallowances are likely and reasonable, based on further investigation and information brought forward by the APSC Staff and other parties. Hearings in the rate case are scheduled to begin December 19, 2006. A decision by the APSC on the rate case application should occur no later than the second quarter of 2007.

Enogex Expansion Projects

Enogex completed its initial project to expand its gathering pipeline capacity on the west side of its system, which was put into service in August 2006. This expansion initiative should enable Enogex to benefit from economic growth opportunities in that marketplace. Enogex continues to have additional opportunities to expand this project, which it is considering.

Termination of Continental Connector Project

On November 4, 2005, Enogex announced that it had entered into a letter of intent with El Paso Corporation (El Paso) relating to El Paso s Continental Connector Project. The letter of intent contemplated arrangements by which El Paso or an affiliate would execute a lease of capacity on the Enogex pipeline system and the leased Enogex pipeline capacity would become part of the Continental Connector Project. The letter of intent expired on April 28, 2006. In early October, El Paso determined not to proceed with its proposed Continental Connector project. Enogex did not incur any material expenditures relating to this proposed project.

Oklahoma City Dayton Tire Plant Closing

In July 2006, the Boards of Directors of Bridgestone Firestone North American Tire and its parent company, Bridgestone Americas Holding Inc., approved the closing of the Oklahoma City Dayton tire plant, which is expected to close by the end of 2006. The closing of this plant will have no effect on the Company s 2006 earnings guidance. However, the closing of this plant is expected to reduce net income by approximately $1.1 million, or $0.01 per diluted share, in 2007.

2006 Outlook

The Company previously disclosed in its Form 10-Q for the quarter ended June 30, 2006 that its 2006 earnings guidance was $207 million to $221 million of income from continuing operations, or $2.25 to $2.40 per diluted share. The Company has changed its consolidated earnings guidance to $198 million to $207 million of income from continuing operations, or $2.15 to $2.25 per diluted share, assuming approximately 92.1 million average diluted shares outstanding, cash flow from operations of between $379 million and $388 million and an effective tax rate of 36.3 percent. The change in earnings guidance reflects nine months of actual results for the Company and lower earnings expectations at Enogex primarily due to the timing and delay of income recognition at Enogex. These delays include lower than previously expected gathering and processing volumes associated with new business; a lower of cost or market write-down of operational storage volumes; and timing for over/under recovered fuel which requires that under recovered fuel be expensed when incurred and over recovered fuel be deferred until collected. In addition, lower commodity spreads reduced projected earnings in the processing business. These items were offset in part by a higher tax benefit at the holding company.

	Previous earnings guidance		Revised earnings guidance	
(In millions, except per share data)	Dollars	Diluted EPS	Dollars	Diluted EPS
OG&E	$134 - $139	$1.46 - $1.51	$134 - $139	$1.46 - $1.51
Enogex	$77 - $86	$0.84 - $0.93	$65 - $69	$0.70 - $0.75
Holding Company	($4) - ($4)	($0.04) - ($0.04)	($1) - ($1)	($0.01) - ($0.01)
Total	$207 - $221	$2.25 - $2.40	$198 - $207	$2.15 - $2.25

Key assumptions for 2006 are:

As shown above, OG&E s earnings guidance remains unchanged at $134 million to $139 million, or $1.46 to $1.51 per diluted share. There were no material changes to OG&E s assumptions underlying this guidance (see Outlook in the Company s Form 10-Q for the quarter ended June 30, 2006 for a description of the underlying assumptions related to OG&E s earnings guidance).

Enogex

As shown above, Enogex s earnings guidance has been changed from $77 million to $86 million, or $0.84 to $0.93 per diluted share, to $65 million to $69 million, or $0.70 to $0.75 per diluted share. Key factors and assumptions underlying this guidance include:

- Total Enogex anticipated gross margin of approximately $290 million to $294 million as compared to approximately $312 million to $327 million assumed in the previous 2006 earnings guidance. The revised guidance includes:
  - Transportation and storage gross margin contribution of approximately $121 million as compared to approximately $131 million assumed in the previous 2006 earnings guidance. Key factors affecting the revised transportation and storage gross margin as compared to the previous 2006 earnings guidance are:
    - The requirement to record operational storage volumes at the lower of cost or market, which is expected to reduce gross margin by approximately $6.4 million; and
    - Higher fuel under recoveries, which is expected to reduce gross margin by approximately $3.6 million.
  - Gathering and processing gross margin contribution of approximately $169 million as compared to approximately $172 million to $187 million assumed in the previous 2006 earnings guidance. Key factors affecting the revised gathering and processing gross margin as compared to the previous 2006 earnings guidance are:
    - Delay in anticipated gathering and processing volumes associated with new business, which is expected to reduce gross margin by approximately $8.4 million;
    - The reduction in the commodity price forecast, which is expected to reduce gross margin by approximately $5.9 million. The commodity price assumptions are listed below;
    - Realized commodity spreads are approximately $4.00 per Million British thermal unit (MMBtu) in 2006 as compared to $3.54 to $5.01 per MMBtu previously anticipated. The commodity spread range for the processing business is based on a combination of $4.00 per MMBtu realized for the first three quarters of 2006 and approximately 65 percent of production volumes that have price risk hedged for the remainder of 2006. The remaining production volumes are subject to market prices; and
    - Included in the above commodity spreads are assumptions on natural gas prices of $6.09 per MMBtu in 2006 as compared to the $6.35 to $6.60 per MMBtu previously anticipated and average natural gas liquids prices of $1.13 per gallon in 2006 as compared to $0.93 to $1.22 per gallon previously anticipated.
  - Marketing gross margin contribution of approximately $0 to $4 million, as compared to $9 million in the previous 2006 earnings guidance, primarily due to the timing of income recognition from hedges;
- Higher operating expenses of approximately $3 million compared to the previous forecast primarily due to the anticipated settlement charge associated with pension expense and costs related to pipeline system integrity; and
- Capital expenditures for investment in Enogex s pipeline system are approximately $70 million to $80 million in 2006.

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 approximately $1 million, or $0.01 per diluted share, from a loss of approximately $4 million, or $0.05 per diluted share. The change is the result of several factors, 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 including a tax true-up adjustment for 2005; and
- Interest expense decreases slightly in 2006 from 2005 due to lower levels of short-term debt offset by higher short-term interest rates.

2007 Outlook

The Company s 2007 earnings guidance is between $213 million to $231 million of income from continuing operations, or $2.30 to $2.50 per diluted share, assuming approximately 92.4 million average diluted shares outstanding, cash flow from operations of between $371 million and $389 million and an effective tax rate of 32.6 percent.

	Earnings guidance per Q3 2006 10-Q	
(In millions, except per share data)	Dollars	Diluted EPS
OG&E	$154 - $162	$1.67 - $1.75
Enogex	$63 - $72	$0.68 - $0.78
Holding Company	($3) - ($4)	($0.03) - ($0.05)
Total	$213 - $231	$2.30 - $2.50

Key assumptions for 2007 are:

OG&E

- Normal weather patterns are experienced;
- Gross margin on weather-adjusted, retail electric sales increases approximately two percent;
- Arkansas rate increase of approximately $3 - $7 million beginning in the first half of 2007 ($6 - $14 million on an annualized basis);
- Wind power rider of approximately $22.6 million in Oklahoma;
- Operating expense decrease of approximately $5 million primarily due to the anticipated pension expense in 2006 partially offset by increased employee and benefit costs as well as costs associated with the Centennial Wind Farm;
- Other expense decreases approximately $4 million due in large part to a loss in the second quarter of 2006 related to the retirement of certain generating assets dedicated to a large industrial customer;
- Interest costs increase approximately $4 million primarily due to higher levels of long-term debt;
- Decrease in effective tax rate due to federal and state credits related to the wind farm; and
- Capital expenditures for investment in OG&E s generation, transmission and distribution system are projected to be $325 million in 2007, which excludes capital expenditures associated with a proposed power plant and environmental expenditures associated with regional haze.

Enogex

Total Enogex anticipated gross margin of approximately $312 million to $328 million as compared to approximately $290 million to $294 million assumed in the 2006 earnings guidance:

Transportation and storage gross margin contribution of approximately $136 million as compared to approximately $121 million assumed in the 2006 earnings guidance. Key factors affecting the revised transportation and storage gross margin as compared to 2006 earnings guidance are:

Timing associated with the over/under recovered fuel and a reduction in pipeline imbalance expense increases gross margin by approximately $9.7 million; and

Increase in storage demand fees increases gross margin by approximately $4.8 million.

Gathering and processing gross margin contribution of approximately $167 million to $183 million as compared to approximately $169 million assumed in the 2006 earnings guidance. Key factors affecting the gathering and processing gross margin are:

Growth in Enogex s gathering business, which increases volumes by six percent from 2006 and gross margin by approximately $12.4 million;
Fuel recoveries increase gross margin in the gathering business by approximately $8.1 million;

These gross margin increases in the gathering business are partially offset by lower contractual gains of approximately $6.1 million due to lower natural gas prices;
Margins in the processing business are expected to be approximately $5.4 million lower from 2006 as a nine percent increase in processing volumes is offset by lower commodity prices based on the mid-point of the commodity spread range. The commodity price assumptions are listed below;
Realized commodity spreads are $2.69 to $3.21 per MMBtu in 2007 as compared to $4.00 per MMBtu assumed in the 2006 earnings guidance; and
Included in the above commodity spreads are assumptions on natural gas prices of $6.33 to $6.62 per MMBtu in 2007 as compared to $6.09 per MMBtu in the 2006 earnings guidance and average natural gas liquids prices of $0.93 to $1.02 per gallon in 2007 as compared to $1.13 per gallon assumed in the 2006 earnings guidance.

Marketing gross margin contribution of approximately $9 million as compared to approximately $0 to $4 million in 2006 primarily due to the timing of income recognition from hedges;

Operating expenses increase approximately $11 million primarily due to increased employee costs as a result of system growth, higher materials and supplies costs and increased depreciation expense associated with higher capital investment from business expansion;
Net interest expense increases approximately $7 million due to lower interest income primarily due to the redeployment of capital previously earning interest income; and
Capital expenditures for investment in Enogex s pipeline system are approximately $80 million to $90 million in 2007.

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 2007 earnings guidance.

Holding Company

For 2007, the Company s earnings guidance for the holding company reflects an expected loss of approximately $3 million to $4 million, or $0.03 to $0.05 per diluted share, from an expected loss of approximately $1 million, or $0.01 per diluted share, for 2006. The higher loss is primarily due to a one-time income tax benefit realized in 2006.

Results of Operations

The following discussion and analysis presents factors that affected the Company s consolidated results of operations for the three and nine months ended September 30, 2006 as compared to the same period in 2005 and the Company s consolidated financial position at September 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 September 30,		**Nine Months Ended September 30,**	
(In millions, except per share data)	**2006**	2005	**2006**	2005
Operating income	**$ 220.6**	$ 188.9	**$ 390.1**	$ 283.5
Net income	**$ 121.4**	$ 111.1	**$ 240.0**	$ 154.9
Basic average common shares outstanding	**91.1**	90.4	**90.9**	90.2
Diluted average common shares outstanding	**92.4**	90.8	**92.0**	90.6
Basic earnings per average common share	**$ 1.33**	$ 1.23	**$ 2.64**	$ 1.72
Diluted earnings per average common share	**$ 1.31**	$ 1.22	**$ 2.61**	$ 1.71
Dividends declared per share	**$ 0.3325**	$ 0.3325	**$ 0.9975**	$ 0.9975

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 September 30,		**Nine Months Ended September 30,**	
(In millions)	**2006**	2005	**2006**	2005
OG&E (Electric Utility)	**$ 195.5**	$ 164.0	**$ 294.1**	$ 221.8
Enogex (Natural Gas Pipeline)	**25.5**	25.0	**97.2**	60.9
Other Operations (A)	**(0.4)**	(0.1)	**(1.2)**	0.8
Consolidated operating income	**$ 220.6**	$ 188.9	**$ 390.1**	$ 283.5

(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 September 30,		Nine Months Ended September 30,	
(Dollars in millions)	**2006**	2005	**2006**	2005
Operating revenues	**$ 608.7**	$ 612.9	**$ 1,427.4**	$ 1,308.0
Cost of goods sold	**293.6**	328.3	**760.9**	719.2
Gross margin on revenues	**315.1**	284.6	**666.5**	588.8
Other operation and maintenance	**74.1**	73.0	**233.8**	230.1
Depreciation	**32.5**	34.7	**98.8**	99.2
Taxes other than income	**13.0**	12.9	**39.8**	37.7
Operating income	**195.5**	164.0	**294.1**	221.8
Allowance for equity funds used during construction	**2.3**	---	**2.5**	---
Other income (loss)	**0.2**	(0.3)	**---**	0.7
Other expense	**0.3**	0.8	**9.0**	1.6
Interest income	**0.3**	0.3	**1.7**	1.9
Interest expense	**21.0**	15.1	**46.2**	34.5
Income tax expense	**69.6**	48.7	**92.8**	60.9
Net income	**$ 107.4**	$ 99.4	**$ 150.3**	$ 127.4
Operating revenues by classification				
Residential	**$ 273.8**	$ 261.4	**$ 584.6**	$ 525.6
Commercial	**146.9**	148.4	**347.0**	320.0
Industrial	**100.7**	110.7	**276.4**	258.6
Public authorities	**57.1**	57.9	**138.1**	127.5
Sales for resale	**20.5**	21.4	**51.4**	48.2
Provision for refund on gas transportation and storage case	**---**	---	**---**	(2.1)
System sales revenues	**599.0**	599.8	**1,397.5**	1,277.8
Off-system sales revenues	**1.2**	2.6	**2.3**	3.9
Other	**8.5**	10.5	**27.6**	26.3
Total operating revenues	**$ 608.7**	$ 612.9	**$ 1,427.4**	$ 1,308.0
MWH (A) sales by classification (in millions)				
Residential	**3.0**	3.0	**6.9**	6.8
Commercial	**1.8**	1.8	**4.8**	4.6
Industrial	**1.9**	1.9	**5.4**	5.4
Public authorities	**0.8**	0.8	**2.2**	2.1
Sales for resale	**0.5**	0.4	**1.2**	1.1
System sales	**8.0**	7.9	**20.5**	20.0
Off-system sales	**---**	---	**---**	---
Total sales	**8.0**	7.9	**20.5**	20.0
Number of customers	**754,447**	743,811	**754,447**	743,811
Average cost of energy per KWH (B) - cents				
Fuel	**3.074**	3.635	**3.164**	3.036
Fuel and purchased power	**3.417**	3.884	**3.520**	3.363
Degree days (C)				
Heating				
Actual	**10**	3	**1,596**	1,870
Normal	**29**	30	**2,228**	2,229
Cooling				
Actual	**1,508**	1,390	**2,391**	2,035
Normal	**1,295**	1,295	**1,850**	1,850

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

OG&E s operating income increased approximately $31.5 million during the three months ended September 30, 2006 as compared to the same period in 2005 primarily due to higher gross margin on revenues (gross margin).

Gross margin, which is operating revenues less cost of goods sold, was approximately $315.1 million during the three months ended September 30, 2006 as compared to approximately $284.6 million during the same period in 2005, an increase of approximately $30.5 million or 10.7 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 $17.7 million;
- price variance due to sales and customer mix, which increased the gross margin by approximately $8.3 million;
- new customer growth in OG&E s service territory, which increased the gross margin by approximately $4.6 million; and
- increased peak demand by industrial customers in OG&E s service territory, which increased the gross margin by approximately $2.0 million.

Cost of goods sold for OG&E consists of fuel used in electric generation and purchased power. Fuel expense was approximately $225.5 million during the three months ended September 30, 2006 as compared to approximately $274.3 million during the same period in 2005, a decrease of approximately $48.8 million or 17.8 percent due to a lower average cost of natural gas per kwh. Purchased power costs were approximately $68.1 million during the three months ended September 30, 2006 as compared to approximately $54.0 million during the same period in 2005, an increase of approximately $14.1 million or 26.1 percent. This increase was primarily due to a power purchase contract that allowed OG&E to make economic purchases during peak demand summer months.

Other operating and maintenance expenses were approximately $74.1 million during the three months ended September 30, 2006 as compared to approximately $73.0 million during the same period in 2005, an increase of approximately $1.1 million or 1.5 percent. The increase in other operating and maintenance expenses was primarily due to:

- a decrease in capitalized work of approximately $4.3 million; and
- higher allocations from the holding company of approximately $3.2 million primarily due to an increase in incentive compensation.

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

- a decrease in outside and professional services of approximately $3.0 million;
- a decrease in miscellaneous expenses of approximately $1.3 million;
- a decrease in materials and supplies expense of approximately $0.8 million; and
- lower salaries, wages, pension and other employee expenses of approximately $0.5 million.

Depreciation expense was approximately $32.5 million during the three months ended September 30, 2006 as compared to approximately $34.7 million during the same period in 2005, a decrease of approximately $2.2 million or 6.3 percent. The decrease in depreciation expense was primarily due to:

a decrease in depreciation rates that was implemented January 1, 2006 as approved by the OCC in December 2005; and

a decrease due to the retirement of assets at June 30, 2006 related to a power supply contract with a large industrial customer that expired June 1, 2006.

Allowance for equity funds used during construction was approximately $2.3 million during the three months ended September 30, 2006 due to construction costs associated with OG&E s wind farm that exceeded the average daily short-term borrowings in the third quarter of 2006. There was no allowance for equity funds used during construction for the three months ended September 30, 2005.

Other income includes, among other things, contract work performed, non-operating rental income and miscellaneous non-operating income. Other income was approximately $0.2 million during the three months ended September 30, 2006 as compared to a reduction in other income of approximately $0.3 million during the same period in

2005, which resulted in an increase in other income of approximately $0.5 million, primarily due to a reduction in income related to the guaranteed flat bill tariff of approximately $0.4 million during 2005.

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 $0.3 million during the three months ended September 30, 2006 as compared to approximately $0.8 million during the same period in 2005, a decrease of approximately $0.5 million or 62.5 percent, primarily due to a reduction of approximately $0.7 million to the previously recorded asset retirement obligation for certain turbines due to an agreement with a third party to provide removal and remediation services (See Note 4 of Notes to Condensed Consolidated Financial Statements for a further discussion).

Net interest expense includes interest income, interest expense and other interest charges. Net interest expense was approximately $20.7 million during the three months ended September 30, 2006 as compared to approximately $14.8 million during the same period in 2005, an increase of approximately $5.9 million or 39.9 percent. The increase in net interest expense was primarily due to:

- increased interest of approximately $7.5 million due to the one-time recognition of interest expense associated with a certain water storage agreement; and
- increased interest of approximately $0.6 million due to increased borrowings from the holding company to cover increased construction costs.

These increases in net interest expense were partially offset by:

- a decrease in interest expense of approximately $2.1 million related to the Company making a deposit with the Internal Revenue Service (IRS) in August 2006 in anticipation that a portion of prior year deductions will be disallowed, which enabled OG&E to cease accruing interest in August 2006; and
- a decrease in interest expense due to an increase in the allowance for borrowed funds used during construction of approximately $0.9 million.

Income tax expense was approximately $69.6 million during the three months ended September 30, 2006 as compared to approximately $48.7 million during the same period in 2005, an increase of approximately $20.9 million or 42.9 percent primarily due to higher pre-tax income for OG&E and a decrease in state tax credits in 2006.

Nine months ended September 30, 2006 as compared to nine months ended September 30, 2005

OG&E s operating income increased approximately $72.3 million during the nine months ended September 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 $666.5 million during the nine months ended September 30, 2006 as compared to approximately $588.8 million during the same period in 2005, an increase of approximately $77.7 million or 13.2 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 $40.9 million;
- price variance due to sales and customer mix, which increased the gross margin by approximately $15.0 million;
- new customer growth in OG&E s service territory, which increased the gross margin by approximately $9.4 million;
- warmer weather in OG&E s service territory, which increased the gross margin by approximately $6.5 million; and
- increased peak demand by industrial customers in OG&E s service territory, which increased the gross margin by approximately $5.7 million.

Fuel expense was approximately $585.5 million during the nine months ended September 30, 2006 as compared to approximately $578.2 million during the same period in 2005, an increase of approximately $7.3 million or 1.3 percent due to slightly increased generation by OG&E s natural gas-fired plants, in addition to a slightly higher average cost of coal per kwh. Purchased power costs were approximately $175.4 million during the nine months ended September 30, 2006 as compared to approximately $141.0 million during the same period in 2005, an increase of approximately $34.4 million or 24.4 percent. This increase was primarily due to a power purchase contract that allowed OG&E to make economic purchases during peak demand summer months.

Other operating and maintenance expenses were approximately $233.8 million during the nine months ended September 30, 2006 as compared to approximately $230.1 million during the same period in 2005, an increase of approximately $3.7 million or 1.6 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher salaries, wages, pension and other employee expenses of approximately $7.2 million;
- higher allocations from the holding company of approximately $7.1 million primarily due to an increase in incentive compensation;
- additional accrual of approximately $2.2 million for the settlement of a claim; and
- higher bad debt expense of approximately $2.1 million.

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

- a decrease in outside services of approximately $7.1million;
- an increase in capitalized work of approximately $6.4 million; and
- a decrease in materials and supplies expense of approximately $2.3 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 $98.8 million during the nine months ended September 30, 2006 as compared to approximately $99.2 million during the same period in 2005, a decrease of approximately $0.4 million or 0.4 percent. The decrease in depreciation expense was primarily due to:

- a decrease in depreciation rates that was implemented January 1, 2006 as approved by the OCC in December 2005; and
- a decrease due to the retirement of assets at June 30, 2006 related to a power supply contract with a large industrial customer which expired June 1, 2006.

These decreases in depreciation expense were partially offset by:

- a higher level of depreciable plant; and
- depreciation expense associated with the acquisition of the McClain Plant, which expenses ceased being recorded as a regulatory asset on July 8, 2005.

Taxes other than income were approximately $39.8 million during the nine months ended September 30, 2006 as compared to approximately $37.7 million during the same period in 2005, an increase of approximately $2.1 million or 5.6 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.

Allowance for equity funds used during construction was approximately $2.5 million during the nine months ended September 30, 2006 due to construction costs associated with OG&E s wind farm that exceeded the average daily short-term borrowings in 2006. There was no allowance for equity funds used during construction for the nine months ended September 30, 2005.

Other income was approximately $0.7 million during the nine months ended September 30, 2005. There was no other income during the nine months ended September 30, 2006. The decrease in other income from 2005 was primarily due to:

a reduction in income of approximately $0.3 million related to the guaranteed flat bill tariff during 2006; and

a gain of approximately $0.2 million in the first quarter of 2005 from the sale of miscellaneous assets.

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Other expense was approximately $9.0 million during the nine months ended September 30, 2006 as compared to approximately $1.6 million during the same period in 2005, an increase of approximately $7.4 million. The increase in other expense was primarily due to:

- a loss on the retirement of fixed assets of approximately $6.1 million; and
- a write-down of natural gas inventory of approximately $0.4 million.

Net interest expense was approximately $44.5 million during the nine months ended September 30, 2006 as compared to approximately $32.6 million during the same period in 2005, an increase of approximately $11.9 million or 36.5 percent. The increase in net interest expense was primarily due to:

- increased interest of approximately $7.5 million due to the one-time recognition of interest expense associated with a certain water storage agreement;
- increased interest of approximately $4.8 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 $2.1 million due to increased borrowings from the holding company to cover increased construction costs.

These increases in net interest expense were partially offset by:

- a decrease in interest expense of approximately $2.2 million related to the Company making a deposit with the IRS in August 2006 in anticipation that a portion of prior year deductions will be disallowed, which enabled OG&E to cease accruing interest in August 2006; and
- a decrease in interest expense due to an increase in the allowance for borrowed funds used during construction of approximately $2.0 million.

Income tax expense was approximately $92.8 million during the nine months ended September 30, 2006 as compared to approximately $60.9 million during the same period in 2005, an increase of approximately $31.9 million or 52.4 percent primarily due to higher pre-tax income for OG&E and a decrease in state tax credits in 2006.

Enogex Continuing Operations

(Dollars in millions)	**Three Months Ended September 30, 2006**	2005	**Nine Months Ended September 30, 2006**	2005
Operating revenues	**$ 557.2**	$ 1,108.3	**$ 1,838.0**	$ 3,062.4
Cost of goods sold	**490.4**	1,047.5	**1,616.4**	2,892.1
Gross margin on revenues	**66.8**	60.8	**221.6**	170.3
Other operation and maintenance	**26.3**	22.4	**80.3**	67.7
Depreciation	**10.6**	9.8	**31.2**	29.8
Impairment of assets	**0.3**	---	**0.3**	---
Taxes other than income	**4.1**	3.6	**12.6**	11.9
Operating income	**25.5**	25.0	**97.2**	60.9
Other income	**0.2**	0.2	**6.4**	0.7
Other expense	**0.1**	--	**0.2**	0.1
Interest income	**2.9**	0.3	**8.7**	1.4
Interest expense	**7.8**	8.3	**23.8**	24.4
Income tax expense	**8.0**	6.9	**33.9**	15.2
Income from continuing operations	**$ 12.7**	$ 10.3	**$ 54.4**	$ 23.3
New well connects (A)	**55**	59	**154**	160
Gathered volumes TBtu/d (B)	**0.97**	0.92	**0.97**	0.91
Incremental transportation volumes TBtu/d	**0.53**	0.46	**0.48**	0.38
Total throughput volumes TBtu/d	**1.50**	1.38	**1.45**	1.29
Natural gas processed TBtu/d	**0.54**	0.51	**0.53**	0.53
Natural gas liquids sold (keep-whole) million gallons	**97**	63	**257**	225
Natural gas liquids sold (POL and fixed-fee) million gallons	**4**	4	**10**	11
Total natural gas liquids sold million gallons	**101**	67	**267**	236
Average sales price per gallon	**$ 0.934**	$ 0.972	**$ 0.914**	$ 0.812

(A) Excludes wells added behind central receipt points.

(B) Trillion British thermal units per day.

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

Enogex s operating income increased approximately $0.5 million during the three months ended September 30, 2006 as compared to the same period in 2005. Increased gross margins in Enogex s gathering and processing and marketing businesses, largely as a result of higher commodity spreads and business growth in 2006 as compared to 2005, were largely offset by a decreased gross margin in Enogex s transportation and storage business and higher operating and maintenance expenses.

Transportation and storage contributed approximately $24.9 million of Enogex s gross margin during the three months ended September 30, 2006 as compared to approximately $27.4 million during the same period in 2005, a decrease of approximately $2.5 million or 9.1 percent. The gross margin decreased primarily due to:

- a lower of cost or market adjustment related to storage of natural gas used to operate the pipeline in the third quarter of 2006, which reduced the 2006 gross margin by approximately $6.4 million as there was no comparable item during the three months ended September 30, 2005; and
- an increase in the fuel over recovery reserve of approximately $1.8 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.

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

- better management of gas pipeline imbalances as Enogex reduced its exposure to gas imbalances while taking advantage of favorable market price movement in the third quarter of 2006 and gas imbalance expense recognized by the gathering business in the third quarter of 2006 (previously carried by the transportation and storage business in 2005), which increased the gross margin by approximately $2.8 million in 2006; and
- increased commodity, interruptible and low and high pressure revenues primarily due to the change in allocation methods of bundled rates, which increased the gross margin by approximately $1.5 million.

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Gathering and processing contributed approximately $41.7 million of Enogex s gross margin during the three months ended September 30, 2006 as compared to approximately $40.3 million during the same period in 2005, an increase of approximately $1.4 million or 3.5 percent. The gathering and processing gross margin increased primarily due to increased net keep-whole margins largely as a result of higher commodity spreads in 2006 as compared to 2005 and increased volumes due to business growth, which increased the gross margin by approximately $7.1 million.

The increase in the gathering and processing gross margin was partially offset by:

- the recognition of imbalance expense in the third quarter of 2006 (previously carried by the transportation and storage business in 2005), which reduced the gross margin by approximately $3.2 million in 2006; and
- a decrease in fuel recoveries of approximately $1.3 million as a result of the Company transitioning to zone fuel rates in 2006 coupled with an increase in over recoveries in 2006 in the East zone.

Marketing contributed approximately $0.2 million of Enogex s gross margin during the three months ended September 30, 2006 as compared to a reduction in the gross margin of approximately $6.9 million during the same period in 2005, an increase in the gross margin of approximately $7.1 million. The gross margin increased primarily due to:

- gains in storage activity, which increased the gross margin by approximately $12.8 million; and
- more favorable market conditions on transportation contracts, which increased the gross margin by approximately $4.0 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 third quarter of 2006, which reduced the 2006 gross margin by approximately $6.2 million; and
- a decrease in the gross margin due to trading activity of approximately $2.6 million.

Enogex s other operating and maintenance expenses were approximately $26.3 million during the three months ended September 30, 2006 as compared to approximately $22.4 million during the same period in 2005, an increase of approximately $3.9 million or 17.4 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher salaries, wages, pension and other employee expenses of approximately $4.0 million primarily due to incentive compensation and hiring additional employees to support business growth; and
- higher outside service costs of approximately $0.7 million primarily related to business development projects and work performed to maintain the integrity and safety of Enogex s pipeline.

These increases in other operating and maintenance expenses were partially offset by a decrease in the reserve for uncollectible accounts of approximately $0.7 million due to improved collection efforts.

Depreciation expense was approximately $10.6 million during the three months ended September 30, 2006 as compared to approximately $9.8 million during the same period in 2005, an increase of approximately $0.8 million or 8.2 percent, primarily due to assets placed into service during the third quarter of 2006.

Taxes other than income was approximately $4.1 million during the three months ended September 30, 2006 as compared to approximately $3.6 million during the same period in 2005, an increase of approximately $0.5 million or 13.9 percent, primarily due to increased ad valorem taxes in 2006 and a franchise tax refund received in 2005.

Net interest expense was approximately $4.9 million during the three months ended September 30, 2006 as compared to approximately $8.0 million during the same period in 2005, a decrease of approximately $3.1 million or 38.8 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 $8.0 million during the three months ended September 30, 2006 as compared to approximately $6.9 million during the same period in 2005, an increase of approximately $1.1 million or 15.9 percent primarily due to higher pre-tax income for Enogex.

For the three months ended September 30, 2006, Enogex s net income, including the discontinued operations discussed below under the caption Enogex Discontinued Operations, was approximately $12.1 million. During the three months ended September 30, 2006, Enogex had a decrease in net income of approximately $0.8 million relating to items that the Company does not consider to be reflective of the ongoing profitability of Enogex s businesses. These decreases in net income include:

loss from discontinued operations of approximately $0.6 million; and

impairment of certain long-lived assets of approximately $0.2 million.

For the three months ended September 30, 2005, Enogex s net income, including the discontinued operations discussed below under the caption Enogex Discontinued Operations, was approximately $15.0 million. During the three months ended September 30, 2005, Enogex had an increase in net income of approximately $4.7 million that the Company does not consider to be reflective of the ongoing profitability of Enogex s business related to income from discontinued operations.

Nine months ended September 30, 2006 as compared to nine months ended September 30, 2005

Enogex s operating income increased approximately $36.3 million during the nine months ended September 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 higher commodity spreads and business growth in 2006 as compared to 2005. The increases in gross margin were partially offset by higher operating and maintenance expenses.

Transportation and storage contributed approximately $93.0 million of Enogex s gross margin during the nine months ended September 30, 2006 as compared to approximately $75.5 million during the same period in 2005, an increase of approximately $17.5 million or 23.2 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 and gas imbalance expense recognized by the gathering business in 2006 (previously carried by the transportation and storage business in 2005), which increased the gross margin by approximately $12.1 million in 2006;

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 $5.5 million;

increased commodity, interruptible and low and high pressure revenues primarily due to higher volumes, which increased the gross margin by approximately $4.5 million;

storage field hedging gains, which increased the gross margin by approximately $3.5 million;

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 $3.3 million; and

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.

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

a lower of cost or market adjustment related to storage of natural gas used to operate the pipeline during 2006, which reduced the 2006 gross margin by approximately $8.3 million as there was no comparable item during the first nine months of 2005; and an increase in the fuel over recovery reserve of approximately $6.9 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.

Gathering and processing contributed approximately $122.0 million of Enogex s gross margin during the nine months ended September 30, 2006 as compared to approximately $103.8 million during the same period in 2005, an increase of approximately $18.2 million or 17.5 percent. The gathering and processing gross margin increased primarily due to:

increased net keep-whole margins primarily due to higher commodity spreads in 2006 as compared to 2005 and increased volumes due to business growth, which increased the gross margin by approximately $24.0 million;

contractual fuel gains primarily due to higher natural gas prices in 2006, which increased the gross margin by approximately $4.2 million;

a reduction in fuel recovery reserve expense of approximately $2.5 million as the gathering and processing business was in an under recovered position during 2006; and

increased activity on natural gas sales reflective of opportunities in the marketplace, which increased the gross margin by approximately $2.0 million.

These increases in the gathering and processing gross margin were partially offset by the recognition of imbalance expense in 2006 (previously carried by the transportation and storage business in 2005), which reduced the gross margin by approximately $10.8 million in 2006.

Marketing contributed approximately $6.6 million of Enogex s gross margin during the nine months ended September 30, 2006 as compared to a reduction in the gross margin of approximately $9.0 million during the same period in 2005, an increase in the gross margin of approximately $15.6 million. The gross margin increased primarily due to:

gains in storage activity, which increased the gross margin by approximately $12.7 million;

more favorable market conditions on transportation contracts, which increased the gross margin by approximately $5.6 million; and

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 15 of Notes to Condensed Consolidated Financial Statements).

These increases in the marketing gross margin were partially offset by a lower of cost or market adjustment related to natural gas in storage during 2006, which reduced the 2006 gross margin by approximately $9.9 million.

Enogex s other operating and maintenance expenses were approximately $80.3 million during the nine months ended September 30, 2006 as compared to approximately $67.7 million during the same period in 2005, an increase of approximately $12.6 million or 18.6 percent. The increase in other operating and maintenance expenses was primarily due to:

higher salaries, wages, pension and other employee expenses of approximately $10.3 million primarily due to incentive compensation and hiring additional employees to support business growth;

higher outside service costs of approximately $3.2 million primarily related to business development projects and work performed to maintain the integrity and safety of Enogex s pipeline; and

higher materials and supplies costs of approximately $1.0 million primarily related to work performed to maintain the integrity and safety of Enogex s pipeline, higher cost of materials and increased materials used at newly added facilities.

These increases in other operating and maintenance expenses 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.

Depreciation expense was approximately $31.2 million during the nine months ended September 30, 2006 as compared to approximately $29.8 million during the same period in 2005, an increase of approximately $1.4 million or 4.7 percent, primarily due to new assets placed into service during 2006.

Taxes other than income was approximately $12.6 million during the nine months ended September 30, 2006 as compared to approximately $11.9 million during the same period in 2005, an increase of approximately $0.7 million or 5.9 percent, primarily due to increased ad valorem taxes in 2006 and a franchise tax refund received in 2005.

Other income was approximately $6.4 million during the nine months ended September 30, 2006 as compared to approximately $0.7 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 16 of Notes to Condensed Consolidated 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 $15.1 million during the nine months ended September 30, 2006 as compared to approximately $23.0 million during the same period in 2005, a decrease of approximately $7.9 million or 34.3 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 $33.9 million during the nine months ended September 30, 2006 as compared to approximately $15.2 million during the same period in 2005, an increase of approximately $18.7 million primarily due to higher pre-tax income for Enogex.

For the nine months ended September 30, 2006, Enogex s net income, including the discontinued operations discussed below under the caption Enogex Discontinued Operations, was approximately $90.4 million. During 2006, Enogex had an increase in net income of approximately $40.6 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 $36.0 million;
- litigation settlement (see Note 16 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.

These increases in net income were partially offset by a decrease in net income of approximately $0.2 million related to the impairment of certain long-lived assets.

For the nine months ended September 30, 2005, Enogex s net income, including the discontinued operations discussed below under the caption Enogex Discontinued Operations, was approximately $34.3 million. During 2005, Enogex had an increase in net income of approximately $6.5 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 $11.0 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 $34.1 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 nine months ended September 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 nine months ended September 30, 2006. Results for the discontinued operations are summarized and discussed below.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	**2006**	2005	**2006**	2005
Operating revenues	**$ ---**	$ 29.5	**$ 9.4**	$ 83.7
Cost of goods sold	**---**	21.0	**4.9**	53.9
Gross margin on revenues	**---**	8.5	**4.5**	29.8
Other operation and maintenance	**---**	2.2	**1.0**	6.4
Depreciation	**---**	1.4	**0.3**	4.8
Taxes other than income	**---**	0.4	**0.1**	1.2
Operating income	**---**	4.5	**3.1**	17.4
Other income (loss)	**(1.0)**	3.0	**56.0**	3.0
Other expense	**---**	(0.7)	**---**	(0.3)
Net interest expense	**---**	1.1	**---**	3.4
Income tax expense (benefit)	**(0.4)**	2.4	**23.1**	6.3
Net income (loss)	**$ (0.6)**	$ 4.7	**$ 36.0**	$ 11.0

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

Following the sale of EAPC in October 2005 and the Kinta gathering assets in May 2006, no operations of EAPC or the Kinta gathering assets are reflected in the Condensed Consolidated Financial Statements except as discussed below.

Other income decreased approximately $4.0 million during the three months ended September 30, 2006 as compared to the same period in 2005 due to a reduction in the gain previously recorded for the sale of the Kinta gathering assets in May 2006.

Net interest expense decreased approximately $1.1 million during the three months ended September 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 decreased approximately $2.8 million during the three months ended September 30, 2006 as compared to the same period in 2005 primarily due to the sale of Enerven in August 2005.

Nine months ended September 30, 2006 as compared to nine months ended September 30, 2005

Gross margin decreased approximately $25.3 million or 84.9 percent during the nine months ended September 30, 2006 as compared to the same period in 2005 primarily due to the sale of EAPC in October 2005, the sale of the Kinta gathering assets in May 2006 and a decrease in natural gas purchases and sales due to a decrease in natural gas transported prior to these assets being sold.

Operating and maintenance expense decreased approximately $5.4 million or 84.4 percent during the nine months ended September 30, 2006 as compared to the same period in 2005 primarily due to the sale of EAPC in October 2005 and the sale of the Kinta gathering assets in May 2006.

Depreciation expense decreased approximately $4.5 million or 93.8 percent during the nine months ended September 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 $53.0 million during the nine months ended September 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 $3.4 million during the nine months ended September 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 $16.8 million during the nine months ended September 30, 2006 as compared to the same period in 2005 primarily due to the sale of the Kinta gathering assets in May 2006 partially offset by the sale of Enerven in August 2005.

Financial Condition

The balance of Deposit with the IRS was approximately $32.0 million at September 30, 2006 due to the Company making a deposit with the IRS on August 17, 2006 in anticipation that a portion of prior year deductions will be disallowed. The deposit enabled the Company to cease accruing interest effective August 17, 2006. See Note 9 of Notes to Condensed Consolidated Financial Statements for a further discussion.

The balance of Accounts Receivable was approximately $449.4 million and $591.4 million at September 30, 2006 and December 31, 2005, respectively, a decrease of approximately $142.0 million or 24.0 percent, primarily due to lower natural gas sales prices by Enogex partially offset by an increase in OG&E s billings to its customers reflecting higher seasonal sales in September 2006 as compared to December 2005.

The balance of current Price Risk Management assets was approximately $73.6 million and $116.5 million at September 30, 2006 and December 31, 2005, respectively, a decrease of approximately $42.9 million or 36.8 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 September 30, 2006 from December 31, 2005 also contributed to the decrease.

The balance of Gas Imbalance asset was approximately $12.0 million and $32.0 million at September 30, 2006 and December 31, 2005, respectively, a decrease of approximately $20.0 million or 62.5 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 $6.2 million and $15.7 million at September 30, 2006 and December 31, 2005, respectively, a decrease of approximately $9.5 million or 60.5 percent due to the expiration of 2005 park and loan transactions in OERI s business activities. Operational imbalances were approximately $5.8 million and $16.3 million at September 30, 2006 and December 31, 2005, respectively, a decrease of approximately $10.5 million or 64.4 percent primarily due to lower pricing.

The balance of Construction Work in Progress was approximately $199.8 million and $101.8 million at September 30, 2006 and December 31, 2005, respectively, an increase of approximately $98.0 million or 96.3 percent, 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 $155.2 million and $90.2 million at September 30, 2006 and December 31, 2005, respectively, an increase of approximately $65.0 million or 72.1 percent, primarily due to pension plan contributions during 2006.

The balance of Accounts Payable was approximately $251.0 million and $510.4 million at September 30, 2006 and December 31, 2005, respectively, a decrease of approximately $259.4 million or 50.8 percent, primarily due to lower natural gas prices in September 2006 as compared to December 2005.

The balance of Accrued Taxes was approximately $97.8 million and $67.1 million at September 30, 2006 and December 31, 2005, respectively, an increase of approximately $30.7 million or 45.8 percent, primarily due to an increase in the Company s estimated income tax liability and the timing of payments and accruals of ad valorem taxes.

The balance of Long-Term Debt Due Within One Year was approximately $128.0 million at September 30, 2006 due to OG&E s $125.0 million principal amount 6.65 percent Senior Notes containing a one-time option of the holders to request repayment between May 15, 2007 and June 15, 2007. There was no long-term debt due within one year at December 31, 2005. See Future Capital Requirements Long-Term Debt with Optional Redemption Provisions for a further discussion.

The balance of current Price Risk Management liabilities was approximately $39.1 million and $109.5 million at September 30, 2006 and December 31, 2005, respectively, a decrease of approximately $70.4 million or 64.3 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 September 30, 2006 from December 31, 2005 also contributed to the decrease.

The balance of Gas Imbalance liability was approximately $13.0 million and $36.0 million at September 30, 2006 and December 31, 2005, respectively, a decrease of approximately $23.0 million or 63.9 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 $10.2 million at December 31, 2005. There were no park and loan transactions that were in a liability position at September 30, 2006. The decrease in park and loan transactions was due to the expiration of 2005 park and loan transactions in OERI s business activities. Operational imbalances were approximately $13.0 million and $25.8 million at September 30, 2006 and December 31, 2005, respectively, a decrease of approximately $12.8 million or 49.6 percent primarily due to lower pricing.

The balance of Fuel Clause Over Recoveries was approximately $39.8 million at September 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 nine months ended September 30, 2006 exceeding OG&E s cost of fuel primarily due to lower than expected 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.

Off-Balance Sheet Arrangements

There have been no significant changes in the Company s off-balance sheet arrangements from those discussed in the Company s Form 10-K for the year ended December 31, 2005.

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

The Company s current estimate for 2006 capital expenditures is approximately $535 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 early 2007. The Company s current estimate for 2007 and 2008 capital expenditures is approximately $415 million and $420 million, respectively. These capital expenditures do not include capital expenditures related to environmental expenditures for regional haze or capital expenditures related to the construction of a proposed power plant with American Electric Power s subsidiary, Public Service Company of Oklahoma, and the Oklahoma Municipal Power Authority (OMPA).

Other Regulatory Matters

In October 2006, OG&E issued requests for proposal (RFP) for energy purchases for the summer of 2007, coal purchases for periods beginning in January 2007 through December 2011 and gas supply purchases for periods beginning in November 2006 through March 2007. In late 2006 or early 2007, OG&E expects to issue an RFP for additional capacity and/or firm energy for the summer periods of 2008 through 2010.

Pension and Postretirement Benefit Plans

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 nine months of 2006 as compared to the first nine 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 last quarter of a particular year, the Company currently expects that it could be required to record a pension settlement charge for 2006 of between $18 million and $20.6 million in the fourth quarter of 2006. 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.

Pension Plan Costs and Assumptions

On August 17, 2006, President Bush signed The Pension Protection Act of 2006 (the Pension Protection Act) into law. The Pension Protection Act makes changes to important aspects of qualified retirement plans. Among other things, it introduces a new funding requirement for single- and multi-employer defined benefit pension plans, provides legal certainty on a prospective basis for cash balance and other hybrid plans and addresses contributions to defined contribution plans, deduction limits for contributions to retirement plans and investment advice provided to plan participants. The Company is currently analyzing the impact of the Pension Protection Act on its pension plans.

Long-Term Debt with Optional Redemption Provisions

OG&E s $125.0 million principal amount 6.65 percent Senior Notes (Senior Notes) due July 15, 2027, are repayable on July 15, 2007, at the option of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to July 15, 2007. Only holders who submit requests for repayment between May 15, 2007 and June 15, 2007 are entitled to such repayments. In accordance with SFAS No. 6, Classification of Short-Term Obligations Expected to Be Refinanced, OG&E reclassified the Senior Notes from long-term debt to long-term debt due within one year at September 30, 2006 due to the one-time put option of the Senior Notes. However, based on where the Senior Notes have recently traded, OG&E does not believe it is probable that this option will be exercised by the note holders.

SPP Letter of Credit

On October 31, 2006, OG&E submitted a letter of credit to the SPP for approximately $2.9 million related to the costs of upgrades required for OG&E to obtain transmission service from its new wind farm.

Future Sources of Financing

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

Short-Term Debt

OG&E expects to increase its available borrowing capacity under its revolving credit agreement in the fourth quarter of 2006. Also, in October 2006, OG&E filed applications with the FERC and the OCC to increase its authorized short-term borrowing capacity. See Note 13 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 16 and 17 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 16 and 17 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 September 30, 2006.

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

Non-Trading Activities

The prices of natural gas, natural gas liquids and natural gas liquids processing spreads are subject to fluctuations resulting from changes in supply and demand. The changes in these prices have a direct effect on the compensation 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 September 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

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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 quarters ended March 31, 2006 and June 30, 2006 for a description of certain legal proceedings presently pending. Except as set forth below and in Notes 16 and 17 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 filed a motion to dismiss the amended petition on August 2, 2006. The hearing on the dismissal motion is expected to be scheduled in the fourth quarter of 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.

Natural Gas Measurement Case

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, the Company has been involved in legal proceedings with Jack J. Grynberg related to the improper or intentional measurement of gas. On October 20, 2006, the District Court of Wyoming ruled on Grynberg s appeal, following and confirming the recommendation of the special master as it relates to Enogex Inc., Enogex Services Corp., Transok, Inc. and OG&E, dismissing all claims for lack of subject matter jurisdiction. The time for appeal for the October 20, 2006 order has not yet run.

Item 1A. Risk Factors.

There have been no significant changes in the Company s risk factors from those 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
7/1/06 7/31/06	26,400	$37.65	N/A	N/A
8/1/06 8/31/06	---	---	N/A	N/A
9/1/06 9/30/06	14,566	$35.09	N/A	N/A

N/A 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

November 1, 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: November 1, 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: November 1, 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 September 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.

November 1, 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