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, 2004

OR

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

Commission File Number: 1-12579

OGE ENERGY CORP.

(Exact name of registrant as specified in its charter)

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes_X_ No___

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act).
Yes _X_ No___

As of October 31, 2004, 88,980,115 shares of common stock, par value $0.01 per share, were outstanding.

OGE ENERGY CORP.

FORM 10-Q

FOR THE QUARTER ENDED SEPTEMBER 30, 2004

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements.

OGE ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

(In millions)	**September 30, 2004**	December 31, 2003
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 28.1**	$ 245.6
Accounts receivable, less reserve of $4.6 and $4.2, respectively	**409.2**	350.2
Accrued unbilled revenues	**67.8**	38.0
Fuel inventories	**119.5**	163.3
Materials and supplies, at average cost	**50.3**	45.1
Price risk management	**141.6**	61.3
Gas imbalance	**33.1**	70.0
Accumulated deferred tax assets	**11.9**	9.4
Fuel clause under recoveries	**48.9**	4.0
Other	**7.3**	21.5
Total current assets	**917.7**	1,008.4
OTHER PROPERTY AND INVESTMENTS, at cost	**36.7**	34.7
PROPERTY, PLANT AND EQUIPMENT		
In service	**5,857.3**	5,596.3
Construction work in progress	**120.6**	56.7
Other	**9.6**	15.0
Total property, plant and equipment	**5,987.5**	5,668.0
Less accumulated depreciation	**2,456.2**	2,358.5
Net property, plant and equipment	**3,531.3**	3,309.5
DEFERRED CHARGES AND OTHER ASSETS		
Recoverable take or pay gas charges	**32.5**	32.5
Income taxes recoverable from customers, net	**31.0**	31.6
Intangible asset - unamortized prior service cost	**40.2**	40.2
Prepaid benefit obligation	**100.7**	55.7
Price risk management	**30.8**	13.5
Other	**65.1**	58.6
Total deferred charges and other assets	**300.3**	232.1

TOTAL ASSETS	**$4,786.0**	$4,584.7

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

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

(In millions)	**September 30, 2004**	December 31, 2003
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 10.2**	$ 202.5
Accounts payable	**312.3**	280.2
Dividends payable	**29.4**	29.1
Customers' deposits	**46.0**	41.6
Accrued taxes	**74.6**	18.7
Accrued interest	**24.9**	30.7
Accrued interest - unconsolidated affiliate	**3.5**	3.5
Tax collections payable	**9.9**	7.9
Accrued vacation	**18.1**	17.2
Long-term debt due within one year	**38.1**	52.1
Non-recourse debt of joint venture	**1.2**	1.2
Price risk management	**162.1**	46.9
Gas imbalance	**26.9**	22.5
Fuel clause over recoveries	---	32.4
Other	**35.2**	41.2
Total current liabilities	**792.4**	827.7
LONG-TERM DEBT		
Long-term debt	**1,288.0**	1,189.7
Non-recourse debt of joint venture	**39.6**	40.2
Long-term debt - unconsolidated affiliate	**206.2**	206.2
Total long-term debt	**1,533.8**	1,436.1
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued pension and benefit obligations	**175.4**	167.4
Accumulated deferred income taxes	**781.8**	747.3
Accumulated deferred investment tax credits	**38.1**	42.0
Accrued removal obligations, net	**122.1**	116.3
Price risk management	**16.4**	4.5
Provision for payments of take or pay gas	**32.5**	32.5
Asset retirement obligation	**1.1**	---
Other	**13.4**	9.3
Total deferred credits and other liabilities	**1,180.8**	1,119.3
STOCKHOLDERS' EQUITY		
Common stockholders' equity	**662.0**	636.1
Retained earnings	**680.0**	623.9
Accumulated other comprehensive loss, net of tax	**(63.0)**	(58.4)
Total stockholders' equity	**1,279.0**	1,201.6
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$4,786.0**	$4,584.7

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

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

(In millions, except per share data)	Three Months Ended September 30, 2004	Three Months Ended September 30, 2003	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
OPERATING REVENUES				
Electric Utility operating revenues	**$ 535.9**	$ 540.3	**$ 1,251.7**	$ 1,230.9
Natural Gas Pipeline operating revenues	**788.8**	519.7	**2,270.1**	1,731.9
Total operating revenues	**1,324.7**	1,060.0	**3,521.8**	2,962.8
COST OF GOODS SOLD				
Electric Utility cost of goods sold	**267.3**	254.3	**669.6**	634.0
Natural Gas Pipeline cost of goods sold	**737.0**	467.3	**2,108.5**	1,578.0
Total cost of goods sold	**1,004.3**	721.6	**2,778.1**	2,212.0
Gross margin on revenues	**320.4**	338.4	**743.7**	750.8
Other operation and maintenance	**89.0**	90.3	**273.2**	273.7
Depreciation	**43.5**	43.5	**133.7**	133.1
Impairment of assets	**8.6**	---	**8.6**	1.0
Taxes other than income	**16.7**	17.3	**52.4**	51.4
OPERATING INCOME	**162.6**	187.3	**275.8**	291.6
OTHER INCOME (EXPENSE)				
Other income	**5.2**	0.3	**10.9**	7.0
Other expense	**(0.1)**	(2.8)	**(3.1)**	(6.3)
Net other income (expense)	**5.1**	(2.5)	**7.8**	0.7
INTEREST INCOME (EXPENSE)				
Interest income	**0.4**	0.2	**1.3**	0.5
Interest on long-term debt	**(18.5)**	(18.5)	**(55.6)**	(56.7)
Interest on trust preferred securities	---	(4.3)	---	(13.0)
Interest expense - unconsolidated affiliate	**(4.3)**	---	**(13.0)**	---
Allowance for borrowed funds used during construction	**0.9**	0.1	**1.2**	0.5
Interest on short-term debt and other interest charges	**(0.6)**	(1.6)	**(2.6)**	(5.1)
Net interest expense	**(22.1)**	(24.1)	**(68.7)**	(73.8)
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	**145.6**	160.7	**214.9**	218.5
INCOME TAX EXPENSE	**51.0**	59.4	**71.5**	80.7
INCOME FROM CONTINUING OPERATIONS BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	**94.6**	101.3	**143.4**	137.8
DISCONTINUED OPERATIONS				
Income (loss) from discontinued operations	---	(0.5)	**0.7**	1.7
Income tax expense	---	1.3	**0.3**	2.2
Income (loss) from discontinued operations	---	(1.8)	**0.4**	(0.5)
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	**94.6**	99.5	**143.8**	137.3
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING FOR ENERGY TRADING CONTRACTS, NET OF TAX OF $3.7	---	---	---	(5.9)
NET INCOME	**$ 94.6**	$ 99.5	**$ 143.8**	$ 131.4
BASIC AVERAGE COMMON SHARES OUTSTANDING	**87.8**	82.4	**87.6**	80.1
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**88.3**	82.7	**88.1**	80.4
BASIC EARNINGS (LOSS) PER AVERAGE COMMON SHARE				
Income from continuing operations	**$ 1.08**	$ 1.23	**$ 1.64**	$ 1.72
Loss from discontinued operations, net of tax	---	(0.02)	---	(0.01)
Loss from cumulative effect of accounting change, net of tax	---	---	---	(0.07)
NET INCOME	**$ 1.08**	$ 1.21	**$ 1.64**	$ 1.64

DILUTED EARNINGS (LOSS) PER AVERAGE COMMON

SHARE								
Income from continuing operations	$	**1.07**	$	1.22	$	**1.63**	$	1.71
Loss from discontinued operations, net of tax		**---**		(0.02)		**---**		(0.01)
Loss from cumulative effect of accounting change, net of tax		**---**		---		**---**		(0.07)
NET INCOME	$	**1.07**	$	1.20	$	**1.63**	$	1.63
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)	**2004**	2003
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	**$ 143.8**	$ 131.4
Adjustments to reconcile net income to net cash provided from operating activities		
(Income) loss from discontinued operations	**(0.4)**	0.5
Cumulative effect of change in accounting principle	**---**	5.9
Depreciation	**133.7**	133.1
Impairment of assets	**8.6**	1.0
Deferred income taxes and investment tax credits, net	**29.2**	91.5
Gain on sale of assets	**(6.3)**	(5.7)
Price risk management assets	**(95.8)**	(22.0)
Price risk management liabilities	**122.2**	12.5
Other assets	**(50.3)**	(20.8)
Other liabilities	**7.5**	4.8
Change in certain current assets and liabilities		
Accounts receivable, net	**(49.0)**	(42.3)
Accrued unbilled revenues	**(29.8)**	(30.7)
Fuel, materials and supplies inventories	**38.6**	(29.8)
Gas imbalance asset	**36.9**	(12.3)
Fuel clause under recoveries	**(44.9)**	(6.6)
Other current assets	**5.6**	4.3
Accounts payable	**32.1**	(26.2)
Customers' deposits	**4.4**	1.3
Accrued taxes	**55.9**	2.5
Accrued interest	**(5.8)**	(7.5)
Fuel clause over recoveries	**(32.4)**	---
Gas imbalance liability	**4.4**	(2.2)
Other current liabilities	**3.5**	17.9
Net Cash Provided from Operating Activities	**311.7**	200.6
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	**(357.2)**	(140.1)
Proceeds from sale of assets	**9.1**	15.7
Other investing activities	**0.7**	0.3
Net Cash Used in Investing Activities	**(347.4)**	(124.1)
CASH FLOWS FROM FINANCING ACTIVITIES		
Retirement of long-term debt	**(57.2)**	(19.0)
Decrease in short-term debt, net	**(192.3)**	(178.2)
Proceeds from long-term debt	**138.6**	---
Premium on issuance of common stock	**15.8**	144.1
Distribution (to) from minority interest	**0.2**	(2.5)
Dividends paid on common stock	**(87.3)**	(72.2)
Net Cash Used in Financing Activities	**(182.2)**	(127.8)
DISCONTINUED OPERATIONS		
Net cash provided from (used in) operating activities	**0.4**	(2.0)

Net cash provided from investing activities	---	38.1
Net Cash Provided from Discontinued Operations	**0.4**	36.1
NET DECREASE IN CASH AND CASH EQUIVALENTS	**(217.5)**	(15.2)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**245.6**	44.4
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 28.1**	$ 29.2

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

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

1. Summary of Significant Accounting Policies

Organization

OGE Energy Corp. (collectively, with its subsidiaries, the “Company”) is an energy and energy services provider offering physical delivery and management of both electricity and natural gas 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 intercompany transactions have been eliminated in consolidation.

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

The operations of the Natural Gas Pipeline segment are conducted through Enogex Inc. and its subsidiaries (“Enogex”) and consist of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing of natural gas. Enogex’s focus is to utilize its gathering, processing, transportation and storage capacity to execute physical, financial and service transactions to capture revenues across different commodities, locations or time periods. The vast majority of Enogex’s natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. Through a 75 percent interest in the NOARK Pipeline System Limited Partnership (“NOARK”), Enogex also owns a controlling interest in and operates the Ozark Gas Transmission System (“Ozark”), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. During the third quarter of 2004, Enogex entered into a joint venture arrangement with a third party and contributed certain of its natural gas compression assets to use in the joint venture, whose primary business focus will be the rental of compression assets. Enogex created a wholly-owned limited liability company, Enogex Compression Company, LLC (“Enogex Compression”), to act as the participating entity in the joint venture. Enogex Compression holds a majority ownership in the joint venture and the third party acts as the manager and conducts the daily operations of the joint venture. Enogex Compression has been consolidated in the Company’s financial statements with a minority interest recorded.

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 “Distragas” method. The Distragas method is a three-factor formula that uses an equal weighting of payroll, operating income and assets. 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, 2004 and December 31, 2003, the results of its operations for the three and nine months ended September 30, 2004 and 2003, and the results of its cash flows for the nine months ended September 30, 2004 and 2003, 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, 2004 are not necessarily indicative of the results that may be expected for the year ending December 31, 2004 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, 2003.

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 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 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. Excluding recoverable take or pay gas charges and the regulatory asset associated with the McClain Plant acquisition, regulatory assets are being amortized and reflected in rates charged to customers over periods of up to 20 years.

OG&E initially records certain costs: (i) that are probable of future recovery as a deferred charge until such time as the cost is approved by a regulatory authority, then the cost is reclassified as a regulatory asset; and (ii) that are probable of future liability as a deferred credit until such time as the amount is approved by a regulatory authority, then the amount is reclassified as a regulatory liability.

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

(In millions)	**September 30, 2004**	December 31, 2003
Regulatory Assets		
Fuel clause under recoveries	**$ 48.9**	$ 4.0
Recoverable take or pay gas charges	**32.5**	32.5
Income taxes recoverable from customers, net	**31.0**	31.6
Unamortized loss on reacquired debt	**21.3**	22.1
Cogeneration capacity payments	**6.6**	---
McClain Plant operating and maintenance expenses	**4.1**	---
January 2002 ice storm	**1.8**	3.6
Miscellaneous	**0.7**	0.4
Total Regulatory Assets	**$ 146.9**	$ 94.2
Regulatory Liabilities		
Accrued removal obligations, net	**$ 122.1**	$ 116.3
Fuel clause over recoveries	**6.4**	32.4
Estimated refund on FERC fuel	**1.0**	1.0
Total Regulatory Liabilities	**$ 129.5**	$ 149.7

Fuel clause under recoveries are generated from under recoveries from OG&E's customers when OG&E's cost of fuel exceeds the amount billed to its customers. Fuel clause over recoveries are generated from over recoveries from OG&E's customers when the amount billed to its customers exceeds OG&E's cost of fuel. 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 allow OG&E to amortize under or over recovery.

Recoverable take or pay gas charges represent outstanding prepayments of gas related to a reserve for litigation that OG&E is currently involved in for which OG&E expects full recovery through its regulatorily approved fuel adjustment clause.

Income taxes recoverable from customers represent income tax benefits previously used to reduce OG&E's revenues. These amounts are being recovered in rates as the temporary differences that generated the income tax benefit turn around. The provisions of SFAS No. 71 allowed OG&E to treat these amounts as regulatory assets and liabilities and they are being amortized over the estimated remaining life of the assets to which they relate. The income tax related regulatory assets and liabilities are netted on the Company's Condensed Consolidated Balance Sheets in the line item, "Income Taxes Recoverable from Customers, Net."

Unamortized loss on reacquired debt is comprised of unamortized debt issuance costs related to the early retirement of OG&E's long-term debt. These amounts are being recovered over the term of the long-term debt which replaced the previous long-term debt.

Cogeneration capacity payments relate to customer savings of approximately $1.0 million per month that began in January 2004 to reflect the expiration of the PowerSmith Cogeneration Project, L.P. ("PowerSmith") contract in August 2004. These customer savings relate to the period from January to August 2004. OG&E started recovering this regulatory asset beginning in September and the remaining balance of approximately $6.6 million will be recovered in the fourth quarter pursuant to filed tariffs.

As a result of the McClain Plant acquisition (further discussed in Note 17) completed on July 9, 2004, OG&E has the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the acquisition and operation of the McClain Plant, consisting of the non-fuel operation and maintenance expenses, depreciation, cost of debt associated with the investment and ad valorem taxes. All prudently incurred costs accrued through the regulatory asset within the 12-month period would be included in OG&E's prospective cost of service and would be recovered over a period to be determined by the OCC.

Accrued removal obligations represent asset retirement costs previously recovered from ratepayers for other than legal obligations. In accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations," the Company was required to reclassify its accrued removal obligations, which had previously been recorded as a liability in Accumulated Depreciation, to a regulatory liability.

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.

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. Amortization of the federal investment tax credits was approximately $1.3 million for each of the three month periods ended September 30, 2004 and 2003 and was approximately $3.9 million for each of the nine month periods ended September 30, 2004 and 2003 and are recorded as income tax benefits in the Condensed Consolidated Statements of Income. During the nine months ended September 30, 2004, the Company recorded Oklahoma state tax credits of approximately $3.2 million, which are recorded as income tax benefits in the Condensed Consolidated Statements of Income.

The Company follows the provisions of SFAS No. 109, “Accounting for Income Taxes,” which uses an asset and liability approach to accounting for income taxes. Under SFAS No. 109,

deferred tax assets or liabilities are computed based on the difference between the financial statement and income tax bases of assets and liabilities using the enacted marginal tax rate. Deferred income tax expenses or benefits are based on the changes in the asset or liability from period to period.

Stock-Based Compensation

Pursuant to the provisions of SFAS No. 123, “Accounting for Stock-Based Compensation,” the Company has elected to continue using the intrinsic value method of accounting for its stock-based employee compensation plans in accordance with Accounting Principles Board (“APB”) Opinion No. 25, “Accounting for Stock Issued to Employees.” Accordingly, the Company has not recognized compensation expense for its stock-based awards to employees.

In December 2002, the FASB issued SFAS No. 148, “Accounting for Stock-Based Compensation – Transition and Disclosure – an amendment of FASB Statement No. 123.” SFAS No. 148 amended the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. The following table reflects pro forma net income and income per average common share had the Company elected to adopt the fair value based method of SFAS No. 123:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions, except per share data)	**2004**	2003	**2004**	2003
Net income, as reported	**$ 94.6**	$ 99.5	**$ 143.8**	$ 131.4
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	**0.3**	0.4	**1.0**	1.1
Pro forma net income	**$ 94.3**	$ 99.1	**$ 142.8**	$ 130.3
Income per average common share				
Basic - as reported	**$ 1.08**	$ 1.21	**$ 1.64**	$ 1.64
Basic - pro forma	**$ 1.07**	$ 1.20	**$ 1.63**	$ 1.63
Diluted - as reported	**$ 1.07**	$ 1.20	**$ 1.63**	$ 1.63
Diluted - pro forma	**$ 1.07**	$ 1.20	**$ 1.62**	$ 1.62

Reclassifications

Certain prior year amounts have been reclassified on the Condensed Consolidated Financial Statements to conform to the 2004 presentation.

2. Accounting Pronouncements

In June 2001, the FASB issued SFAS No. 143, which applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. The scope of SFAS No. 143 includes the Company’s accrued plant removal costs for generation, transmission, distribution, processing and pipeline assets. SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of the fair value can be made. If a reasonable estimate of the fair value cannot be made in the period the asset retirement obligation is incurred, the liability shall be recognized when a reasonable estimate of the fair value can be made. Asset retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes, written or oral contracts, including obligations arising under the doctrine of promissory estoppel. The recognition of an asset retirement obligation is capitalized as part of the carrying amount of the long-lived asset. Asset retirement obligations represent future liabilities and, as a result, accretion expense is accrued on this liability until such time as the obligation is satisfied. In connection with the adoption of SFAS No. 143, the Company assessed whether it had a legal obligation within the scope of SFAS No. 143. The Company determined that it had a legal obligation to retire certain assets. As the Company currently has no plans to retire any of these assets (except as discussed below) and the remaining life is indeterminable, an asset retirement obligation was not recognized; however, the Company will monitor these assets and record a liability when a reasonable estimate of the fair value can be made. During the third quarter of 2004, OG&E determined that it had a legal obligation within the scope of SFAS No. 143 to retire certain assets related to the expiration of a power supply contract in June 2006. OG&E recorded an asset retirement obligation of approximately $1.1 million at September 30, 2004 and plans to amortize this amount for 21 months beginning October 1, 2004.

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51." In October 2003, the FASB issued Interpretation No. 46-6, "Effective Date of FASB Interpretation No. 46, Consolidation of Variable Interest Entities," in which the FASB agreed to defer, for public companies, the required effective dates to implement Interpretation No. 46 for interests held in a variable interest entity ("VIE") or potential VIE that was created before February 1, 2003. The Company adopted this new interpretation effective December 31, 2003 resulting in approximately a $0.8 million pre-tax gain ($0.5 million after tax) which resulted in the consolidation of Energy Insurance Bermuda Ltd. ("EIB") Mutual Business Program No. 19 ("MBP 19"). Effective January 1, 2004, the reinsurer of the MBP 19 program agreed to remove the guarantee requirement which enabled the Company to terminate the standby letter of credit previously provided. However, the reinsurer added a ratings trigger requirement in the revised agreement such that if the commercial paper rating of the Company is lowered by two grades,

MBP 19 may be surcharged an additional premium, which may result in an additional premium to the Company. Since the guarantee requirement was removed, the total equity investment at risk of MBP 19 is sufficient to permit it to finance its activities without additional subordinated financial support from other parties. Therefore, MBP 19 was not considered a VIE as defined in Interpretation No. 46 which resulted in the deconsolidation of MBP 19 during the first quarter of 2004. The Company is currently in the process of terminating the MBP 19 program effective January 1, 2005 and does not expect that this termination will have a material affect on the Company's consolidated financial position or results of operations.

In October 2002, the Emerging Issues Task Force ("EITF") reached a consensus on certain issues covered in EITF Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." One consensus of EITF 02-3 was to rescind EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," as amended, effective for fiscal periods beginning after December 15, 2002. Effective October 25, 2002, all new contracts and physical inventories that would have been accounted for under EITF 98-10 were no longer marked to market through earnings unless the contracts met the definition of a derivative under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. Application of the consensus for energy contracts and inventory that existed on or before October 25, 2002 that remain in effect at the date this consensus was initially applied were recognized as a cumulative effect of a change in accounting principle in accordance with APB Opinion No. 20, "Accounting Changes." As a result, only energy contracts that meet the definition of a derivative in SFAS No. 133 are carried at fair value. The Company adopted this consensus effective January 1, 2003 resulting in a pre-tax loss of approximately $9.6 million ($5.9 million after tax). The loss, which was accounted for as a cumulative effect of a change in accounting principle during the first quarter of 2003, was primarily related to natural gas held in storage for trading purposes. This natural gas held in storage was sold during the first quarter of 2003 resulting in an increase in the gross margin on revenues ("gross margin") in excess of the cumulative effect loss described above.

3. Price Risk Management Assets and Liabilities

Non-Trading Activities

The Company periodically utilizes derivative contracts to manage the exposure of its assets to unfavorable changes in commodity prices, as well as to reduce exposure to adverse interest rate fluctuations. During the three and nine months ended September 30, 2004 and 2003, the Company's use of non-trading price risk management instruments involved the use of commodity price and interest rate swap agreements. These agreements involve the exchange of fixed price or rate payments in exchange for floating price or rate payments over the life of the instrument without an exchange of the underlying principal amount.

In accordance with SFAS No. 133, the Company recognizes all of its derivative instruments as Price Risk Management assets or liabilities in the Condensed Consolidated Balance Sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. The accounting for changes in the fair value of a derivative depends on

the intended use of the derivative and resulting designation. For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative instrument is recognized in current earnings on the same line item as the gain or loss recorded for the change in the fair value of the hedged item. For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of Accumulated Other Comprehensive Income and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portion of a derivative's change in fair value is recognized currently in earnings. As a matter of policy, all hedged items and the derivatives used for cash flow hedges must be identical with respect to time and location and must be in compliance with SFAS No. 133. Forecasted transactions designated as the hedged item in a cash flow hedge are regularly evaluated to assess whether they continue to be probable of occurring. If the forecasted transactions are no longer probable of occurring, hedge accounting will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings. Any amounts recorded in Accumulated Other Comprehensive Income will remain in other comprehensive income until such time as the forecasted transaction is deemed probable not to occur.

The Company's interest rate swap agreements include both fair value and cash flow hedges. The fair value hedges qualify for the shortcut method prescribed by SFAS No. 133. Under the shortcut method, the Company assumes that the hedged item's change in fair value is exactly as much as the derivative's change in fair value. The Company measures ineffectiveness of the cash flow hedges under the hypothetical derivative method prescribed by SFAS No. 133. Under the hypothetical derivative method, the Company has designated that the critical terms of the hedging instrument are the same as the critical terms of the hypothetical derivative used to value the forecasted transaction, and, as a result, no ineffectiveness is expected. See Notes 4 and 12 for a description of the Company's interest rate swap agreements.

Trading Activities

The Company, through its subsidiary, OGE Energy Resources, Inc. ("OERI"), engages in energy trading activities primarily related to the purchase and sale of natural gas. Contracts utilized in these activities generally include forward swap contracts as well as over-the-counter and exchange traded futures and options. Energy trading activities are accounted for in accordance with SFAS No. 133 and EITF 02-3. In accordance with SFAS No. 133, financial instruments that qualify as derivatives are reflected at fair value with the resulting unrealized gains and losses recorded as Price Risk Management assets or liabilities in the Condensed Consolidated Balance Sheets, classified as current or long-term based on their anticipated settlement. Unrealized gains and losses from changes in the market value of open contracts are included in Natural Gas Pipeline Operating Revenues in the Condensed Consolidated Statements of Income. Energy trading contracts resulting in delivery of a commodity that meet the requirements of EITF Issue No. 99-19, "Reporting Revenues Gross as a Principal or Net as an Agent," are included as sales or purchases in the Condensed Consolidated Statements of Income depending on whether the contract relates to the sale or purchase of the commodity.

4. Accumulated Other Comprehensive Loss

The components of total comprehensive income for the three and nine months ended September 30, 2004 and 2003, respectively, are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	**2004**	2003	**2004**	2003
Net income	**$ 94.6**	$ 99.5	**$ 143.8**	$ 131.4
Other comprehensive income (loss), net of tax:				
Deferred hedging gains (losses)	**(3.9)**	0.5	**(4.1)**	0.2
Reversal of unrealized gains on available-for-sale securities	---	---	**(0.4)**	---
Total comprehensive income	**$ 90.7**	$ 100.0	**$ 139.3**	$ 131.6

The components of accumulated other comprehensive loss at September 30, 2004 and December 31, 2003 are as follows:

(In millions)	**September 30, 2004**	December 31, 2003
Minimum pension liability adjustment, net of tax	**$ (59.7)**	$ (59.7)
Deferred hedging gains (losses), net of tax	**(3.3)**	0.9
Unrealized gains on available-for-sale securities, net of tax	---	0.4
Total accumulated other comprehensive loss	**$ (63.0)**	$ (58.4)

Accumulated other comprehensive loss at both September 30, 2004 and December 31, 2003 included approximately a $59.7 million after tax loss ($97.4 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, 2003. Any increases or decreases in the minimum pension liability will be reflected in Other Comprehensive Income or Loss in the fourth quarter.

Cash Flow Hedges

At September 30, 2004, the Company had four outstanding interest rate swap agreements that qualified as cash flow hedges. The Company entered into four separate interest rate swap agreements, effective April 16, 2004, April 21, 2004, May 17, 2004 and July 16, 2004, respectively, to hedge approximately $20.0 million, $30.0 million, $20.0 million and $10.0 million, respectively, of future interest payments of long-term debt expected to be issued later this year related to the redemption of $200.0 million of 8.375 percent trust preferred securities of OGE Energy Capital Trust I, a wholly-owned financing trust of the Company. These interest rate swap agreements originally matured on October 15, 2004 but the maturity date was extended to November 8, 2004. The objective of these interest rate swaps is to protect against the volatility of interest rates affecting future interest payments. These interest rate swaps qualified as cash flow hedges under SFAS No. 133 and met all of the requirements for a determination that there was no ineffective portion as allowed by the hypothetical derivative method under SFAS No. 133.

At September 30, 2004, the fair value for these interest rate swaps was approximately $4.2 million and the hedges were classified as Current Liabilities – Price Risk Management in

the Condensed Consolidated Balance Sheets. A corresponding net decrease of approximately $4.2 million was reflected in Accumulated Other Comprehensive Income at September 30, 2004 as these cash flow hedges were effective at September 30, 2004.

5. Enogex – Discontinued Operations

Enogex sold its interests in the NuStar Joint Venture ("NuStar") for approximately $37.0 million in February 2003. The Company recognized approximately a $1.4 million after tax gain related to the sale of these assets in the first quarter of 2003. Following completion of the final accounting for the NuStar sale, the Company recorded an additional charge of approximately $0.2 million after tax in the third quarter of 2003. The final accounting is subject to approval by all parties to the sale of the joint venture interest. During the first quarter of 2004, the Company recognized approximately $0.4 million after tax from funds received related to an overpayment for natural gas purchases in a prior period.

The Condensed Consolidated Financial Statements of the Company reflect NuStar, which was part of the Natural Gas Pipeline segment, as discontinued operations. Accordingly, revenues, costs and expenses and cash flows of NuStar have been excluded from the respective captions in the Condensed Consolidated Financial Statements and have been reported as "Income (loss) from Discontinued Operations" and "Net Cash Provided from Discontinued Operations." There were no outstanding balances related to NuStar on the Condensed Consolidated Balance Sheets. Summarized financial information for the discontinued operations is as follows:

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(In millions)	Three Months Ended September 30, 2004	2003	Nine Months Ended September 30, 2004	2003
Operating revenues from discontinued operations	**$ ---**	$ ---	**$ 0.7**	$ 7.8
Income (loss) from discontinued operations before taxes	**---**	(0.5)	**0.7**	1.7

6. Asset Disposals

Enogex sold approximately 29 miles of transmission lines of the Ozark pipeline, in which an Enogex subsidiary owns a 75 percent interest, located in Pittsburg and Latimer counties in Oklahoma for approximately $10.0 million in January 2003. Enogex recognized approximately a $5.3 million pre-tax gain and approximately $1.1 million in minority interest expense in the first quarter of 2003 related to the sale of these assets, which is recorded in Other Income and Other Expense, respectively, in the Condensed Consolidated Statements of Income. These assets were part of the Natural Gas Pipeline segment.

In September 2004, OG&E sold its interests in its natural gas producing properties for approximately $3.1 million. These interests had a carrying value of approximately $0.1 million and OG&E recognized a gain of approximately $3.0 million, which is recorded in Other Income in the Condensed Consolidated Statements of Income. These interests were part of the Electric Utility segment.

7. Impairment of Assets

Processing and Compression Assets

During the fourth quarter of 2002, the Company recognized a pre-tax impairment loss of approximately $48.3 million in the Natural Gas Pipeline segment related to Enogex natural gas processing and compression assets. In the fourth quarter of 2003, as a result of an ongoing initiative to improve asset utilization in the Natural Gas Pipeline segment, the Company concluded that certain idle Enogex natural gas compression assets may no longer be required to meet the Company’s future business needs. As a result, the Company recognized a pre-tax impairment loss of approximately $9.2 million related to these natural gas compression assets. The impairments recorded in the fourth quarters of 2002 and 2003 resulted from plans to dispose of these assets at prices below the carrying amount. The fair value of these assets was determined based on third-party evaluations, prices for similar assets, historical data and projected cash flows. Certain of these impaired assets were contributed to the joint venture discussed below.

During the three and nine months ended September 30, 2004, respectively, the Company sold certain of its compression and processing assets for approximately $0.3 million and $5.0 million, respectively, and recognized approximately $0.1 million and $1.8 million, respectively, in after tax gains related to the sale of these assets. The carrying amount of the remaining assets that were the subject of the impairment charges in the fourth quarters of 2002 and 2003 was approximately $2.9 million and $11.9 million at September 30, 2004 and December 31, 2003, respectively. Except as discussed below, these assets are held for sale and the Company plans to sell or otherwise dispose of these assets by the end of 2004.

During the third quarter of 2004, Enogex entered into a joint venture arrangement with a third party and contributed certain of its natural gas compression assets (with a carrying amount of approximately $3.9 million) to the joint venture. The objective of the joint venture is to derive value from the assets by renting the natural gas compressors. Enogex Compression was created to act as the participating entity in the joint venture. Enogex Compression holds a majority ownership in the joint venture, although the actual ownership percentages may fluctuate based on the relative capital contributions of Enogex Compression and the third party member. The third party acts as the manager and conducts the daily operations of the joint venture. These assets are part of the Natural Gas Pipeline segment.

During the third quarter of 2004, the Company reclassified an asset from assets held for sale to assets held and used. This decision was based on the fact that when this asset was previously impaired as discussed above, there was a declining natural gas processing market, declining volumes and a decline in the British thermal unit content of the gas flowing through the processing plants. Since the time of impairment, natural gas prices have increased, and with higher sustained natural gas prices, drilling activity has also significantly increased. Also, new producing wells are also producing richer natural gas that must be processed. As a result, in accordance with SFAS No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets,” the Company determined the fair value of this asset based on historical data and

projected cash flows and recorded a gain of approximately $0.3 million during the third quarter of 2004 related to reclassifying this asset from assets held for sale to assets held and used.

In October 2004, the Company reclassified a large electric compressor that was previously classified as assets held for sale to assets held and used. This compressor has a carrying amount of approximately $1.2 million at September 30, 2004, which is included in the carrying amount of the remaining assets held for sale of approximately $2.9 million discussed above. This decision was based on the fact that, when this asset was previously impaired as discussed above, there was excess horsepower available for compression on the pipeline system and this asset was identified as surplus that would be sold. Since the time of impairment, it has become economical to reactivate this compressor due to higher fuel costs related to natural gas compression and changes to the compression requirements for the pipeline. The Company is currently in the process of determining the fair value of this asset and does not expect this decision to have a material affect on the Company’s consolidated financial position or results of operations.

Pipeline Assets

During the third quarter of 2004, the Company recognized a pre-tax impairment loss of approximately $8.6 million in the Natural Gas Pipeline segment related to Enogex natural gas pipeline assets. During September 2004, Enogex received notification from a customer that a transportation agreement involving four of Enogex’s non-contiguous pipeline asset segments located in west Texas and used to serve the customer’s power plants would be terminated effective December 31, 2004. In connection with the preparation of these financial statements, Enogex performed an evaluation on these assets and concluded that an impairment charge needed to be recorded. The primary reason for this determination was that these four pipeline asset segments were originally built for the specific purpose of providing gas transmission service to this customers' four power plants that are now going to be shut down, and, as a result, other alternative commercial uses for these facilities are considered unlikely. The fair value of these assets was determined based on historical data and projected cash flows. Following the impairment charge, the carrying amount of these assets was approximately $0.9 million at September 30, 2004. The depreciation lives for these assets as of September 30, 2004 have been revised based on these circumstances. The Company is currently evaluating other commercial opportunities for these assets as well as contacting other parties that may be interested in acquiring any of these assets.

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)	**2004**	2003
NON-CASH INVESTING AND FINANCING ACTIVITIES		
Change in fair value of long-term debt due to interest rate swaps	**$ (2.5)**	$ (1.8)
Issuance of common stock	**10.0**	16.6

9. Common Stock

In April 2003, the Company filed a Form S-3 Registration Statement to register 7,000,000 shares of the Company's common stock pursuant to the Company's Automatic Dividend Reinvestment and Stock Purchase Plan ("DRIP"). Under the terms of the DRIP, the Company may accept requests for optional investments in amounts greater than $0.1 million per year and may offer a discount of up to three percent from current market prices. This program allows the Company to sell additional common stock at a smaller discount than that normally incurred in a secondary equity offering. During the nine months ended September 30, 2004, the Company issued 721,021 shares at a discount of 1.50 percent pursuant to the DRIP. In October 2004, the Company issued 396,530 shares of common stock at a discount price of 1.25 percent pursuant to the DRIP. Also, as part of the DRIP, the Company issued 49,662 shares of common stock at no discount during the nine months ended September 30, 2004.

For the three and nine months ended September 30, 2004, respectively, there were 50,599 shares of new common stock and 307,823 shares of new common stock issued pursuant to the Company's Stock Incentive Plan, related to exercised stock options.

10. 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)	**2004**	2003	**2004**	2003
Average Common Shares Outstanding				
Basic average common shares outstanding	**87.8**	82.4	**87.6**	80.1
Effect of dilutive securities:				
Employee stock options and unvested stock grants	**0.2**	0.1	**0.2**	0.1
Contingently issuable shares (performance units)	**0.3**	0.2	**0.3**	0.2
Diluted average common shares outstanding	**88.3**	82.7	**88.1**	80.4

For each of the three and nine month periods ended September 30, 2004, approximately 0.7 million shares related to outstanding employee stock options were not included in the calculation of diluted earnings per average common share because the effect of including those shares would be 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 month periods ended September 30, 2003, respectively, approximately 1.9 million shares and 2.0 million shares related to outstanding employee stock options were not included in the calculation of diluted earnings per average common share because the effect of including those shares was anti-dilutive as the exercise price of the stock options exceeded the average common stock market price during the respective period.

11. Trust Originated Preferred Securities

On October 21, 1999, OGE Energy Capital Trust I issued $200.0 million principal amount of 8.375 percent trust preferred securities that mature on October 15, 2039. On October

15, 2004, the Company redeemed all of the outstanding trust preferred securities at $25 per share and issued approximately $170.0 million in commercial paper. The Company expects to refinance a portion of this short-term debt with long-term debt during the fourth quarter of 2004. At September 30, 2004, the trust preferred securities were classified as long-term debt in the Condensed Consolidated Balance Sheets. In October 2004, the Company expects to write off approximately $5.9 million related to unamortized debt issuance costs for the trust preferred securities.

12. Long-Term Debt

At September 30, 2004, the Company is in compliance with all of its debt agreements.

Long-Term Debt with Optional Redemption Provisions

OG&E's 6.500 percent Senior Notes ("Senior Notes") were repayable on July 15, 2004, at the option of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to July 15, 2004. Only holders who submitted requests for repayment between May 15, 2004 and June 15, 2004 were entitled to such repayments. OG&E and the Senior Note Trustee received no such requests for repayment of the Senior Notes.

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 are redeemable at the option of the holder during the next 12 months, are as follows:

SERIES	DATE DUE		AMOUNT
Variable %	Garfield Industrial Authority, January 1, 2025	$	**47.0**
Variable %	Muskogee Industrial Authority, January 1, 2025		**32.4**
Variable %	Muskogee Industrial Authority, June 1, 2027		**56.0**
	Total (redeemable during next 12 months)	$	**135.4**

All of these Bonds are subject to redemption at the option 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. A third party remarketing agent for the Bonds will attempt to remarket any Bonds tendered for purchase. 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.

Early Retirement of Long-Term Debt

In 1998, Enogex issued a note of approximately $5.7 million payable to an unaffiliated former partial interest owner of NOARK. The note had a maturity date of July 1, 2020 and an

interest rate of 7.00 percent. Principal and interest payments of approximately $0.8 million were due annually beginning July 1, 2004. In July 2004, Enogex made the initial $0.8 million payment and also made a payment of approximately $7.8 million, which included accrued interest since inception of the note, to repay the outstanding note balance and satisfy its remaining obligations related to this note. Enogex recorded a pre-tax gain of approximately $0.1 million in the third quarter of 2004 related to this transaction.

Interest Rate Swap Agreements

Fair Value Hedges

At September 30, 2004 and December 31, 2003, the Company had three outstanding interest rate swap agreements that qualified as fair value hedges: (i) OG&E entered into an interest rate swap agreement, effective March 30, 2001, to convert $110.0 million of 7.30 percent fixed rate debt due October 15, 2025, to a variable rate based on the three month London InterBank Offering Rate ("LIBOR") and (ii) Enogex entered into two separate interest rate swap agreements, effective July 15, 2002 and October 24, 2002, to convert a total of $200.0 million ($100.0 million for each interest rate swap agreement) of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the six month LIBOR in arrears. The objective of these interest rate swaps was to achieve a lower cost of debt and to raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standards. These interest rate swaps qualified as fair value hedges under SFAS No. 133 and met all of the requirements for a determination that there was no ineffective portion as allowed by the shortcut method under SFAS No. 133.

At September 30, 2004 and December 31, 2003, the fair values pursuant to the interest rate swaps were approximately $9.3 million and $7.6 million, respectively, and the hedges were classified as Deferred Charges and Other Assets – Price Risk Management in the Condensed Consolidated Balance Sheets. A corresponding net increase of approximately $9.3 million and $7.6 million was reflected in Long-Term Debt at September 30, 2004 and December 31, 2003, respectively, as these fair value hedges were effective at September 30, 2004 and December 31, 2003.

Cash Flow Hedges

At September 30, 2004, the Company had four outstanding interest rate swap agreements that qualified as cash flow hedges. The Company entered into four separate interest rate swap agreements, effective April 16, 2004, April 21, 2004, May 17, 2004 and July 16, 2004, respectively, to hedge approximately $20.0 million, $30.0 million, $20.0 million and $10.0 million, respectively, of future interest payments of long-term debt expected to be issued later this year related to the redemption of $200.0 million of 8.375 percent trust preferred securities of OGE Energy Capital Trust I. See Note 4 for a further discussion of these interest rate swap agreements.

13. Short-Term Debt

The short-term debt balance was approximately $10.2 million and $202.5 million at September 30, 2004 and December 31, 2003, respectively. The balance at December 31, 2003 was primarily due to the incurrence of short-term debt in anticipation of the expected 2003 year-end closing of the acquisition of the McClain Plant, which was completed on July 9, 2004. In conjunction with the acquisition of the McClain Plant, the Company issued short-term debt to fund a portion of the acquisition, and, as a result, the short-term debt balance was approximately $216.1 million at July 31, 2004. On August 4, 2004, OG&E issued $140.0 million of long-term debt to replace these short-term borrowings. See Note 17 for a further discussion of the recent McClain Plant acquisition.

The following table shows the Company's lines of credit in place and available cash at September 30, 2004. Short-term borrowings could include a combination of bank borrowings and commercial paper.

Lines of Credit and Available Cash *(In millions)*

Entity	Amount Available	Amount Outstanding	Maturity
OGE Energy Corp.	$ 15.0	$ ---	April 6, 2005
OG&E (A)	100.0	---	December 9, 2004
OGE Energy Corp. (A)	300.0	---	December 9, 2004
	415.0	---	
Cash	28.1	N/A	N/A
Total	$ 443.1	$ ---	

(A) These lines of credit are used to back up the Company's commercial paper borrowings, which were approximately $10.2 million at September 30, 2004.

On October 20, 2004, the Company and OG&E entered into revolving credit agreements totaling $550 million. These agreements, which include two separate credit facilities, one for the Company in an amount up to $450 million and one for OG&E in an amount up to $100 million, replaced the Company's and OG&E's current credit facilities in the table above that were to expire on December 9, 2004. Each of the new credit facilities has a five-year term with two options to extend the term for one year. For the OG&E credit facility, OG&E filed an application to issue securities with the OCC in September 2004 and received approval of this transaction in October 2004.

The Company's and OG&E's ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade. Their respective back-up lines of credit contain rating grids that require annual fees and borrowing rates to increase if they suffer an adverse ratings impact. The impact of additional downgrades would result in an increase in the cost of short-term borrowings of approximately five to 20 basis points, 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. In October 2004, OG&E filed an application with the FERC to request a two-year renewal of its current regulatory

approval to incur up to $400 million in short-term borrowings at any one time. OG&E's current short-term borrowing authorization expires December 31, 2004.

14. Retirement Plans and Postretirement Benefit Plans

In December 2003, the FASB issued SFAS No. 132 (Revised), "Employer's Disclosures about Pension and Postretirement Benefits, an amendment of FASB Statements No. 87, 88 and 106," which revised the disclosure requirements applicable to employers' pension plans and other postretirement benefit plans. This Statement requires additional disclosures for defined benefit pension plans and other defined benefit postretirement plans, including disclosures describing the components of net periodic benefit cost recognized during interim periods.

The details of the net periodic benefit cost related to the Company's pension plan and postretirement benefit plans included in the Condensed Consolidated Financial Statements is as follows:

Net Periodic Benefit Cost

	Pension Plan			
	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(In millions)	**2004**	2003	**2004**	2003
Service cost	**$ 4.3**	$ 3.8	**$ 12.7**	$ 11.4
Interest cost	**7.4**	7.3	**22.2**	21.9
Return on plan assets	**(7.9)**	(6.2)	**(23.7)**	(18.3)
Amortization of net loss	**2.9**	3.3	**8.9**	9.9
Amortization of unrecognized prior service cost	**1.6**	1.6	**4.8**	4.5
Net periodic benefit cost	**$ 8.3**	$ 9.8	**$ 24.9**	$ 29.4

Postretirement Benefit Plans

(In millions)	Three Months Ended September 30, 2004	Three Months Ended September 30, 2003	Nine Months Ended September 30, 2004	Nine Months Ended September 30, 2003
Service cost	**$ 0.8**	$ 0.8	**$ 2.3**	$ 2.3
Interest cost	**2.8**	2.8	**8.3**	8.2
Return on plan assets	**(1.4)**	(1.4)	**(4.2)**	(4.1)
Amortization of transition obligation	**0.6**	0.7	**2.0**	2.1
Amortization of net loss	**1.3**	0.8	**3.8**	2.5
Amortization of unrecognized prior service cost	**0.5**	0.4	**1.5**	1.4
Net periodic benefit cost	**$ 4.6**	$ 4.1	**$ 13.7**	$ 12.4

Pension Plan Funding

The Company previously disclosed in its Form 10-K for the year ended December 31, 2003 that it expected to contribute approximately $56.0 million to its pension plan in 2004. After the benefit liability was remeasured as of January 1, 2004, the Company decided to make an additional contribution of $13.0 million (for a total anticipated contribution of $69.0 million in 2004) to ensure the pension plan maintains an adequate funded status. The Company

funded this $69.0 million contribution to its pension plan during the second and third quarters of 2004. 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.

Medicare Prescription Drug, Improvement and Modernization Act of 2003

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the “Medicare Act”). The Medicare Act expanded Medicare to include, for the first time, coverage for prescription drugs. Due to various uncertainties related to the Company’s response to this legislation in relation to its postretirement medical plan and the appropriate accounting methodology for this event, the Company elected to defer financial recognition of this legislation until the FASB issued final accounting guidance. This deferral election was permitted under FASB Staff Position No. FAS 106-1, “Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.” In May 2004, the FASB issued FASB Staff Position No. FAS 106-2, “Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.” FAS 106-2 provides guidance on the accounting for the effects of the Medicare Act for employers that sponsor postretirement heath care plans that provide prescription drug benefits. FAS 106-2 also requires those employers to provide certain disclosures regarding the effect of the federal subsidy provided by the Medicare Act. For employers who elected to defer financial recognition, FAS 106-2 provides two alternative methods of adoption which include a retroactive application to the date of the Medicare Act’s enactment or a prospective application as of the date of adoption. For employers who elected not to defer financial recognition, FAS 106-2 requires these employers to recognize a cumulative effect of a change in accounting principle in accordance with APB Opinion No. 20. Adoption of FAS 106-2 is required for financial statements issued for periods beginning after June 15, 2004. The Company adopted this new standard effective July 1, 2004 with retroactive application to the date of the Medicare Act’s enactment. Management expects that the accumulated plan benefit obligation (“APBO”) for the Company’s postretirement medical plan will be reduced by approximately $13.3 million as a result of savings to the Company’s postretirement medical plan resulting from the Medicare Act, which will reduce the Company’s costs for its postretirement medical plan by approximately $2.5 million annually. The $2.5 million in annual savings is comprised of a reduction of approximately $1.5 million from amortization of the $13.3 million gain due to the reduction of the APBO, a reduction in the interest cost on the APBO of approximately $0.8 million and a reduction in the service cost due to the subsidy of approximately $0.2 million.

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. For the three and nine months ended September 30, 2003, Other Operations primarily includes unallocated corporate expenses, interest expense on the trust preferred securities and interest expense on commercial paper. As a result of the adoption of

FASB Interpretation No. 46 on December 31, 2003, and the resulting deconsolidation of the trust preferred securities, Other Operations for the three and nine months ended September 30, 2004 primarily includes unallocated corporate expenses, interest expense to unconsolidated affiliate and interest expense on commercial paper. 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, 2004 and 2003.

Three Months Ended September 30, 2004	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	**$ 535.9**	**$ 816.6**	**$ ---**	**$ (27.8)**	**$ 1,324.7**
Fuel	**220.1**	**---**	**---**	**(13.6)**	**206.5**
Purchased power	**60.8**	**---**	**---**	**---**	**60.8**
Gas and electricity purchased for resale	**---**	**727.9**	**---**	**(14.2)**	**713.7**
Natural gas purchases - other	**---**	**23.3**	**---**	**---**	**23.3**

Cost of goods sold	**280.9**	**751.2**	**---**	**(27.8)**	**1,004.3**
Gross margin on revenues	**255.0**	**65.4**	**---**	**---**	**320.4**
Other operation and maintenance	**65.7**	**25.4**	**(2.1)**	**---**	**89.0**
Depreciation	**30.2**	**11.7**	**1.6**	**---**	**43.5**
Impairment of assets	**---**	**8.6**	**---**	**---**	**8.6**
Taxes other than income	**11.7**	**4.3**	**0.7**	**---**	**16.7**
Operating income (loss)	**147.4**	**15.4**	**(0.2)**	**---**	**162.6**
Other income	**3.5**	**1.5**	**0.2**	**---**	**5.2**
Other expense	**(0.1)**	**0.2**	**(0.2)**	**---**	**(0.1)**
Interest income	**0.2**	**0.6**	**0.6**	**(1.0)**	**0.4**
Interest expense	**(8.9)**	**(9.4)**	**(5.2)**	**1.0**	**(22.5)**
Income tax expense (benefit)	**50.8**	**2.0**	**(1.8)**	**---**	**51.0**
Net income (loss)	**$ 91.3**	**$ 6.3**	**$ (3.0)**	**$ ---**	**$ 94.6**

(A) Natural Gas Pipeline's operations consisted 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, 2004	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	**$ 76.2**	**$ 144.2**	**$ 703.7**	**$ (107.5)**	**$ 816.6**
Operating income (loss)	**$ 8.4**	**$ 17.0**	**$ (10.0)**	**$ ---**	**$ 15.4**

Three Months Ended September 30, 2003	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	$ 540.3	$ 533.3	$ ---	$ (13.6)	$ 1,060.0
Fuel	181.9	---	---	(11.8)	170.1
Purchased power	84.2	---	---	---	84.2
Gas and electricity purchased for resale	---	460.0	---	(1.8)	458.2
Natural gas purchases - other	---	9.1	---	---	9.1
Cost of goods sold	266.1	469.1	---	(13.6)	721.6
Gross margin on revenues	274.2	64.2	---	---	338.4
Other operation and maintenance	71.5	22.1	(3.3)	---	90.3
Depreciation	29.9	11.0	2.6	---	43.5
Taxes other than income	12.0	4.6	0.7	---	17.3
Operating income	160.8	26.5	---	---	187.3
Other income	---	0.1	0.2	---	0.3
Other expense	(0.9)	(0.5)	(1.4)	---	(2.8)
Interest income	0.4	0.2	4.5	(4.9)	0.2
Interest expense	(9.9)	(9.8)	(9.5)	4.9	(24.3)
Income tax expense (benefit)	55.3	6.3	(2.2)	---	59.4
Income (loss) from continuing operations	95.1	10.2	(4.0)	---	101.3
Loss from discontinued operations	---	(1.8)	---	---	(1.8)
Net income (loss)	$ 95.1	$ 8.4	$ (4.0)	$ ---	$ 99.5

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

Three Months Ended	Transportation	Gathering	Marketing	Eliminations	Total

September 30, 2003	and Storage	and Processing			
(In millions)					
Operating revenues	$ 62.4	$ 117.3	$ 435.9	$ (82.3)	$ 533.3
Operating income (loss)	$ 21.0	$ 6.2	$ (0.7)	$ ---	$ 26.5

Nine Months Ended September 30, 2004	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	**$ 1,251.7**	**$ 2,341.3**	**$ ---**	**$ (71.2)**	**$ 3,521.8**
Fuel	**490.9**	**---**	**---**	**(37.7)**	**453.2**
Purchased power	**216.4**	**---**	**---**	**---**	**216.4**
Gas and electricity purchased for resale	**---**	**2,076.7**	**---**	**(33.5)**	**2,043.2**
Natural gas purchases - other	**---**	**65.3**	**---**	**---**	**65.3**
Cost of goods sold	**707.3**	**2,142.0**	**---**	**(71.2)**	**2,778.1**
Gross margin on revenues	**544.4**	**199.3**	**---**	**---**	**743.7**
Other operation and maintenance	**208.7**	**73.8**	**(9.3)**	**---**	**273.2**
Depreciation	**92.4**	**34.6**	**6.7**	**---**	**133.7**
Impairment of assets	**---**	**8.6**	**---**	**---**	**8.6**
Taxes other than income	**36.2**	**13.6**	**2.6**	**---**	**52.4**
Operating income	**207.1**	**68.7**	**---**	**---**	**275.8**
Other income	**4.8**	**4.7**	**1.4**	**---**	**10.9**
Other expense	**(1.3)**	**(0.1)**	**(1.7)**	**---**	**(3.1)**
Interest income	**0.4**	**1.1**	**1.2**	**(1.4)**	**1.3**
Interest expense	**(28.2)**	**(28.8)**	**(14.4)**	**1.4**	**(70.0)**
Income tax expense (benefit)	**61.1**	**15.4**	**(5.0)**	**---**	**71.5**
Income (loss) from continuing operations	**121.7**	**30.2**	**(8.5)**	**---**	**143.4**
Income from discontinued operations	**---**	**0.4**	**---**	**---**	**0.4**
Net income (loss)	**$ 121.7**	**$ 30.6**	**$ (8.5)**	**$ ---**	**$ 143.8**

(A) Natural Gas Pipeline's operations consisted 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, 2004	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	**$ 246.3**	**$ 402.2**	**$ 2,058.8**	**$ (366.0)**	**$ 2,341.3**
Operating income (loss)	**$ 40.0**	**$ 39.5**	**$ (10.8)**	**$ ---**	**$ 68.7**

Nine Months Ended September 30, 2003	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	$ 1,230.9	$ 1,786.1	$ ---	$ (54.2)	$ 2,962.8
Fuel	448.8	---	---	(33.0)	415.8
Purchased power	218.2	---	---	---	218.2
Gas and electricity purchased for resale	---	1,556.3	---	(21.2)	1,535.1
Natural gas purchases - other	---	42.9	---	---	42.9

Cost of goods sold	667.0	1,599.2	---	(54.2)	2,212.0
Gross margin on revenues	563.9	186.9	---	---	750.8
Other operation and maintenance	218.3	66.9	(11.5)	---	273.7
Depreciation	91.7	33.2	8.2	---	133.1
Impairment of assets	---	---	1.0	---	1.0
Taxes other than income	35.7	13.4	2.3	---	51.4
Operating income	218.2	73.4	---	---	291.6
Other income	0.5	5.9	0.6	---	7.0
Other expense	(2.1)	(2.0)	(2.2)	---	(6.3)
Interest income	0.5	0.8	14.3	(15.1)	0.5
Interest expense	(30.0)	(30.1)	(29.3)	15.1	(74.3)
Income tax expense (benefit)	67.4	20.0	(6.7)	---	80.7
Income (loss) from continuing operations	119.7	28.0	(9.9)	---	137.8
Loss from discontinued operations	---	(0.5)	---	---	(0.5)
Income (loss) before cumulative effect of change in accounting principle	119.7	27.5	(9.9)	---	137.3
Cumulative effect on prior years of change in accounting principle, net to tax	---	(5.9)	---	---	(5.9)
Net income (loss)	$ 119.7	$ 21.6	$ (9.9)	$ ---	$ 131.4

(A) Natural Gas Pipeline's operations consisted 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, 2003	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	$ 185.1	$ 392.9	$ 1,514.1	$ (306.0)	$ 1,786.1
Operating income	$ 48.9	$ 14.5	$ 10.0	$ ---	$ 73.4

16. Commitments and Contingencies

Except as set forth below and in Note 17, the circumstances set forth in Note 17 to the Company's Consolidated Financial Statements included in the Company's Form 10-K for the year ended December 31, 2003 and in Note 15 to the Company's Condensed Consolidated Financial Statements included in the Company's Form 10-Q for the quarters ended March 31, 2004 and June 30, 2004, appropriately represent, in all material respects, the current status of any material commitments and contingent liabilities.

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

As reported in Note 17 to the Company's Consolidated Financial Statements in the Company's Form 10-K for the year ended December 31, 2003, Enogex, Central Oklahoma Oil and Gas Corp. ("COOG"), Natural Gas Storage Corporation ("NGSC") and certain individual shareholders of COOG and NGSC, have been involved in legal proceedings relating to a gas storage agreement and associated agreements. The parties participated in the Oklahoma County arbitration in May 2004 and the arbitration panel rendered a decision in the Company's favor for approximately $5.0 million on July 15, 2004. On September 13, 2004 the District Court of Oklahoma County confirmed the arbitration award and the judgment was entered. In the Texas case, on August 20, 2004, a hearing was held and the judge confirmed the decision as to Enogex. Also in the Texas case, on October 4, 2004, the plaintiffs filed a first amended petition seeking: (i) declaratory judgment based on collusion to impair collateral; (ii) gross negligence; and (iii) declaratory judgment and confirmation of certain aspects of the award. The plaintiffs have added a request for punitive damages. The jury trial in the United States District Court, Western District of Oklahoma fraudulent transfer cases against certain of the individual shareholders of COOG and NGSC was held from October 12-26, 2004. The case was submitted to the jury on October 25, 2004 and the jury ruled in favor of the Company and Enogex for approximately $6.6 million.

Farmland Industries

As earlier reported, Farmland Industries, Inc. ("Farmland") voluntarily filed for Chapter 11 bankruptcy protection from creditors on May 31, 2002. Enogex filed its proof of claim on January 7, 2003 for approximately $5.4 million. In April 2003, Enogex negotiated a settlement and received approximately $1.9 million in May 2003. As a general unsecured creditor of Farmland and pursuant to the terms of the settlement agreement referenced above, Enogex received an additional payment of approximately $0.8 million, with the final payment being received on July 30, 2004 for a total payment on Enogex's proof of claim of approximately $2.7 million.

National Steel Corporation

As previously reported in the Company's Form 10-Q for the quarter ended March 31, 2004, National Steel Corporation ("National Steel") voluntarily filed for Chapter 11 bankruptcy protection from creditors in 2002. OERI filed its proof of claim for approximately $0.9 million. In March 2004, National Steel filed an adversary proceeding in the pending bankruptcy against

OERI seeking the refund and return of payments made by National Steel to OERI during the 90 days preceding its bankruptcy filing totaling approximately $2.7 million. A settlement of the pending bankruptcy issues was reached in October 2004 between the parties wherein OERI agreed to not pursue its claim in the bankruptcy (approximately a $12,000 claim based on the filed bankruptcy plan) in exchange for National Steel dismissing the pending preference claim.

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 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. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of currently 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. This assessment of currently pending or threatened lawsuits is subject to change.

17. Rate Matters and Regulation

OG&E's retail electric tariffs are regulated by the OCC in Oklahoma and by the APSC in Arkansas. The issuance of certain securities by OG&E is also regulated by the OCC and the APSC. OG&E's wholesale electric tariffs, short-term borrowing authorization and accounting practices are subject to the jurisdiction of the FERC. The Secretary of the Department of Energy has jurisdiction over some of OG&E's facilities and operations.

Recent Regulatory Matters

2002 Settlement Agreement

On November 22, 2002, the OCC signed a rate order containing the provisions of an agreed-upon settlement (the "Settlement Agreement") of OG&E's rate case. The Settlement Agreement provides for, among other items: (i) a $25.0 million annual reduction in the electric rates of OG&E's Oklahoma customers which went into effect January 6, 2003; (ii) recovery by OG&E, through rate base, of the capital expenditures associated with the January 2002 ice storm; (iii) OG&E to acquire electric generation of not less than 400 megawatts ("MW") ("New Generation") to be integrated into OG&E's generation system; and (iv) recovery by OG&E, over three years, of the $5.4 million in deferred operating costs, associated with the January 2002 ice storm, through OG&E's rider for sales to other utilities and power marketers ("off-system sales"). Previously, OG&E had a 50/50 sharing mechanism in Oklahoma for any off-system sales. The Settlement Agreement provided that the first $1.8 million in annual net profits from OG&E's off-system sales will go to OG&E, the next $3.6 million in annual net profits from off-system sales will go to OG&E's Oklahoma customers, and any net profits of off-system sales in excess of these amounts will be credited in each sales year with 80 percent to OG&E's

Oklahoma customers and the remaining 20 percent to OG&E. If any of the $5.4 million is not recovered at the end of the three years, the OCC will authorize the recovery of any remaining costs. During the first nine months of 2004, OG&E recovered approximately $1.8 million in annual net profits from off-system sales, gave approximately $3.6 million in annual net profits from off-system sales to OG&E's Oklahoma customers and currently, the net profits from off-system sales have exceeded the $5.4 million and are being shared with 80 percent to OG&E's Oklahoma customers and the remaining 20 percent to OG&E.

OCC Order Confirming Savings

The Settlement Agreement requires that, if OG&E did not acquire the New Generation by December 31, 2003, OG&E must credit $25.0 million annually (at a rate of 1/12 of $25.0 million per month for each month that the New Generation is not in place) to its Oklahoma customers beginning January 1, 2004 and continuing through December 31, 2006. As discussed in more detail below, in August 2003 OG&E signed an agreement to purchase a 77 percent interest in the 520 MW NRG McClain Station (the "McClain Plant"), but due to a delay at the FERC, the acquisition was not completed by December 31, 2003. In the interim, OG&E entered into a power purchase agreement with the McClain Plant that delivered the savings guaranteed to OG&E's customers. OG&E requested that the OCC confirm that the steps it had taken, including the power purchase agreement, were satisfying the customer savings obligation under the Settlement Agreement and that OG&E would not be required to begin crediting its customers. On April 28, 2004, the OCC issued an order confirming that OG&E was delivering savings to its customers as required under the Settlement Agreement. The order removed any uncertainty over whether the OCC believed OG&E had to reduce its rates, effective January 1, 2004, while it awaited action by the FERC on its application to purchase the McClain Plant. A party to the OCC proceeding has appealed the OCC's order to the Oklahoma Supreme Court. OG&E currently believes that the appeal is without merit.

Recent Acquisition of Power Plant

On August 18, 2003, OG&E signed an asset purchase agreement to acquire NRG McClain LLC's 77 percent interest in the McClain Plant. The acquisition of this 77 percent interest was intended to satisfy the requirement in the Settlement Agreement to acquire New Generation. The McClain Plant includes natural gas-fired combined cycle combustion turbine units and is located near Newcastle, Oklahoma in McClain County, Oklahoma. The McClain Plant began operating in 2001. The owner of the remaining 23 percent in the McClain Plant is the Oklahoma Municipal Power Authority ("OMPA").

OG&E completed the acquisition of the McClain Plant on July 9, 2004. The purchase price for the interest in the McClain Plant was approximately $160.0 million. The closing was subject to customary conditions including receipt of certain regulatory approvals. Because NRG McClain LLC had filed for bankruptcy protection, the acquisition was subject to approval by the bankruptcy court. As part of the bankruptcy approval process, NRG McClain LLC's interest in the plant was subject to an auction process and on October 28, 2003, the bankruptcy court approved the sale of NRG McClain LLC's interest in the plant to OG&E.

The final approval OG&E had been waiting for was the approval from the FERC. On July 2, 2004, the FERC authorized OG&E to acquire the McClain Plant. The FERC's approval was based on an offer of settlement OG&E filed in a proceeding on March 8, 2004. Under the offer of settlement, 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. Two other parties, InterGen Services, Inc. and AES Shady Point, opposed OG&E's offer of settlement and filed competing settlement offers. In the July 2, 2004 order, the FERC: (i) approved OG&E's offer of settlement subject to conditions; (ii) rejected the competing offers of settlement; and (iii) approved OG&E's acquisition of the McClain Plant. As part of the July 2, 2004 order, OG&E agreed to undertake the following mitigation measures: (i) install transformers at two of its facilities at a cost of approximately $18.5 million; (ii) upgrade one transmission line in OG&E's local service territory; (iii) hire an independent market monitor to oversee OG&E's activity in its control area; and (iv) provide a 600 MW bridge into its control area from the Redbud plant. On October 13, 2004, the independent market monitor filed its first report with the FERC. The market monitoring plan is designed to detect any anticompetitive conduct by OG&E from operation of its generation resources or its transmission system. The market monitoring function is performed daily and periodic reviews are also performed with any findings reported to the FERC. The purpose of this first report is to provide an account of monitoring activities and significant events on OG&E's system during the period from July 10, 2004 to September 30, 2004. During this period, transmission congestion data on OG&E's system, along with data on purchases and sales, generation dispatch data and power flows on OG&E's tie lines were analyzed. The market monitor concluded that OG&E did not act in an anticompetitive manner through either dispatch of its generation or operation of its transmission system. Additionally, OG&E's operations under the ongoing mitigation measures that require OG&E to make available transmission capability available to the Redbud power plant for access to the OG&E system were analyzed. Based on this analysis, the market monitor concluded that OG&E has complied with this requirement. OG&E expects to complete the installation and implementation of these measures by June 2005. One party has filed a request for rehearing of the FERC's July 2, 2004 order. The outcome of that request for rehearing cannot be determined at this time.

OG&E is operating the plant in accordance with a joint ownership and operating agreement with the OMPA. Under this agreement, OG&E operates the facility, and OG&E and the OMPA are entitled to the net available output of the plant based on their respective ownership percentages. All fixed and variable costs, except fuel and gas transportation costs, are shared in proportion to the respective ownership interests. Fuel and gas transportation costs are paid in accordance with each individual owner's respective transportation contract and consumption. OG&E expects to utilize its portion of the output, 400 MWs, to serve its native load. As a result, OG&E expects to file with the OCC a request to increase its rates to its Oklahoma customers to recover, among other things, its investment in, and the operating expenses of, the McClain Plant no later than July 8, 2005. OG&E expects to file a rate case by mid-year 2005 using 2004 as a test year with new approved rates expected to be in effect by the first quarter of 2006. As provided in the Settlement Agreement, until OG&E seeks and obtains approval of a request to increase base rates to recover, among other things, the investment in the plant, OG&E will have the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the acquisition and operation of the McClain Plant, consisting of the non-

fuel operation and maintenance expenses, depreciation, cost of debt associated with the investment and ad valorem taxes. If the OCC were to approve OG&E's request, all prudently incurred costs accrued through the regulatory asset within the 12-month period would be included in OG&E's prospective cost of service and would be recovered over a period to be determined by the OCC.

OG&E temporarily funded the McClain Plant acquisition with short-term borrowings from the Company. On August 4, 2004, OG&E issued $140.0 million of long-term debt to replace these short-term borrowings. Also, on August 9, 2004, the Company made a capital contribution to OG&E of approximately $153.0 million.

OG&E expects the acquisition of the McClain Plant, including the effects of an interim power purchase agreement OG&E had with NRG McClain LLC while OG&E was awaiting regulatory approval to complete the acquisition, will provide savings, over a three-year period, in excess of $75.0 million to its Oklahoma customers. These savings will be derived from: (i) the avoidance of purchase power contracts otherwise needed; (ii) an above market cogeneration contract with PowerSmith when it terminated at the end of August 2004; and (iii) fuel savings associated with operating efficiencies of the new plant. These savings, while providing real savings to Oklahoma customers, are not expected to affect OG&E's profitability because its rates are not expected to be reduced to accomplish these savings. In the event OG&E is unable to demonstrate at least $75.0 million in savings to its customers during this 36-month period, OG&E will be required to credit its Oklahoma customers any unrealized savings below $75.0 million as determined at the end of the 36-month period ending December 31, 2006. At this time, OG&E believes that it will be able to demonstrate at least $75.0 million in savings during this period.

Contract with PowerSmith

In September 2003, PowerSmith filed an application with the OCC seeking to compel OG&E to continue purchasing power from PowerSmith's qualified cogeneration facility under the Public Utility Regulatory Policy Act of 1978 at a price that would include an avoided capacity charge equal to the avoided cost of the McClain Plant. On June 7, 2004, OG&E and PowerSmith signed a 15-year power sales agreement under which OG&E would contract to purchase electric power from PowerSmith. On August 27, 2004, the new 15-year power sales agreement was approved by the OCC and became effective September 1, 2004. OG&E's ability to meet its guarantee of customer savings of at least $75 million over three years is not expected to be materially affected by this new agreement to purchase electric power from PowerSmith.

FERC Section 311 Rate Case

In December 2001, Enogex made its filing at the FERC under Section 311 of the Natural Gas Policy Act to establish rates and a default processing fee and to address various other issues for the combined Enogex and Transok L.L.C. pipeline systems. In May 2003, the FERC accepted the stipulation and settlement agreement and entered an order modifying Enogex's Statement of Operating Conditions ("SOC"). The settlement included a fee to be assessed under certain market conditions to process customer gas gathered behind processing plants so that it meets the heating value standards of natural gas transmission pipelines ("default processing

fee"). This default processing fee, which reduces Enogex's exposure to keep whole processing arrangements, is implemented in the event the natural gas liquids revenue less the associated fuel and shrinkage costs is negative. Pursuant to Enogex's SOC that is effective through September 30, 2004, if Enogex's annual processing gross margin exceeds a specified threshold, Enogex is required to record a default processing fee refund obligation in an amount equal to the lesser of the default processing fees or the amount of the processing margin in excess of the specified threshold.

During the third and fourth quarters of 2003, the Company established approximately a $4.9 million reserve to cover such refund obligations. During April 2004, the Company refunded its default processing fee refund obligation under the SOC to the applicable customers. For the three and nine months ended September 30, 2004, the Company billed default processing fees of approximately $0.2 million, which has been recorded as deferred revenue. For the three months ended September 30, 2003, the Company recorded a net default processing fee reserve of approximately $1.1 million. For the nine months ended

September 30, 2003, the Company recorded net default processing fee revenue of approximately $3.0 million. Based on the forecasted processing gross margin for 2004, any default processing fees billed to customers will be recorded as deferred revenue until it becomes probable that the 2004 gross margin threshold in the SOC will not be exceeded. The accounting for default processing fees is not expected to impact full-year earnings, but could affect the timing of those earnings. Also, during the three months ended September 30, 2004 and 2003, respectively, the Company recognized revenue of approximately $0.1 million and $0.2 million of low flow meter charges. During the nine months ended September 30, 2004 and 2003, respectively, the Company recognized revenue of approximately $0.4 million and $0.6 million of low flow meter charges.

On September 1, 2004, Enogex made a filing at the FERC to revise its previously approved SOC to permit, among other things, the unbundling, effective October 1, 2004, of its previously bundled gathering and transportation services. Thereafter, the FERC will regulate Enogex's Section 311 transportation and any regulation of gathering will be pursuant to Oklahoma statute. Several parties challenged the SOC changes and the filing is currently under review at the FERC. On September 30, 2004, Enogex made a filing at the FERC to update Enogex's Section 311 maximum transportation rate and Enogex expects certain parties to challenge aspects of the rate filing as well. In addition, on September 29, 2004, Enogex filed an updated fuel factor with the FERC. Enogex charges a fixed fuel percentage for natural gas shipped on the Enogex system, and Enogex submits an updated fuel factor annually. One intervenor challenged Enogex's fuel factor filing. The timing of the FERC action on these three filings is uncertain.

Pending Regulatory Matters

Currently, OG&E has two significant matters pending at the OCC: (i) a review of the process completed by OG&E in its selection of gas transportation and storage services to meet its system operating needs; and (ii) security investments on OG&E's system. These matters, as well as several other pending matters, are discussed below.

Gas Transportation and Storage Agreement

As part of the Settlement Agreement, OG&E also agreed to consider competitive bidding for gas transportation service to its natural gas-fired generation facilities pursuant to the terms set forth in the Settlement Agreement. The prescribed bidding process detailed in the Settlement Agreement provided that each generation facility bid separately for the services required. OG&E believes that in order for it to achieve maximum coal generation, which delivers the lowest cost energy to its customers, and ensure reliable electric service, it must have integrated, firm no-notice load following service for both gas transportation and gas storage. This type of service is required to satisfy the daily swings in customer demand placed on OG&E's system and still permit natural gas units to not impede coal energy production. OG&E also believes that gas storage is an integral part of providing gas supply to OG&E's generation facilities. Accordingly, OG&E evaluated its competitive bid options in light of these circumstances. OG&E's evaluation clearly demonstrates that the Enogex integrated gas system provides superior integrated, firm no-notice load following service to OG&E that is not available from other companies serving the OG&E marketplace. On April 29, 2003, as required by the Settlement Agreement, OG&E filed an application with the OCC in which 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 at an annual cost of approximately $46.8 million. During the three months ended September 30, 2004 and 2003, OG&E paid Enogex approximately $13.6 million and $11.8 million, respectively, for gas transportation and storage services. During the nine months ended September 30, 2004 and 2003, OG&E paid Enogex approximately $37.7 million and $33.0 million, respectively, for gas transportation and storage services. Based upon requests for information from intervenors, OG&E requested from Enogex and Enogex retained a "cost of service" consultant to assist in the preparation of testimony related to this case. On January 30, 2004, the OCC issued a procedural schedule for this case. On March 31, 2004, OG&E filed testimony and exhibits with the OCC, which completed the initial documentation required to be filed in this case. On July 12, 2004, several parties filed responsive testimony reflecting various positions on the issues related to this case. In particular, the testimony of the OCC Staff recommended that OG&E be entitled to recover the $46.8 million requested, which results in no refund, and also recommended that OG&E provide at its next general rate review the results of an open competitive bidding process or a comprehensive market study. If OG&E does not provide such open bidding or market study, the OCC Staff recommendation would cap recovery at approximately $40 million at OG&E's next general rate review. The recommendations in the testimony of the Attorney General's office and the Oklahoma Industrial Energy Consumers ("OIEC") would cap recovery at approximately $35 million and $30 million, respectively, with the difference between what OG&E has been collecting through its automatic fuel adjustment clause and these recommended amounts being refunded to customers. On July 26, 2004, the OCC issued a new procedural schedule. OG&E filed rebuttal testimony on August 16, 2004 in this case. Hearings in this case before an administrative law judge occurred from September 16-22, 2004. On October 22, 2004, the administrative law judge overseeing the proceeding recommended approximately $41.9 million annual recovery with OG&E refunding to its customers any amounts collected in excess of this amount. If this recommendation is ultimately accepted, OG&E believes its refund obligation

would be approximately $6.1 million, which the Company does not believe is material in light of previously established reserves. OG&E believes the amount currently paid to Enogex for integrated, firm no-notice load following transportation and storage services is fair, just and reasonable. OG&E appealed the administrative law judge's recommendation on November 1 and a hearing in this case is currently scheduled for November 19. An OCC order in the case is expected by the end of 2004.

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 August 14, 2002, OG&E filed testimony with the OCC outlining proposed expenditures and related actions for security enhancement and a proposed recovery rider. Attempting to make security investments at the proper level, OG&E has developed a set of guidelines intended to minimize long-term or widespread outages, minimize the impact on critical national defense and related customers, maximize the ability to respond to and recover from an attack, minimize the financial impact on OG&E that might be caused by an attack and accomplish these efforts with minimal impact on ratepayers. The OCC Staff retained a security expert to review the report filed by OG&E. On July 13, 2004, the security expert filed testimony that recommended: (i) $19.0 million in capital expenditures and $2.5 million annually in operating and maintenance expenses are justified to enhance the security of OG&E's infrastructure; and (ii) a security rider should be authorized to recover costs as these projects are completed. On August 4, 2004, OG&E filed responsive testimony that quantified the minimal customer impact and revised its request for security investments so that it was consistent with the OCC Staff's recommendations. On August 13, 2004, the only intervening party, the OIEC, filed a statement of position which supported the OCC Staff's recommendations. On October 28, 2004, all parties signed a joint stipulation that contains the OCC Staff's recommendations and authorizes a $5 million annual recovery from OG&E's customers for security enhancement. The hearing in this case is currently scheduled for November 9-11, 2004 and an OCC order in the case is expected in early 2005.

On October 17, 2003, the OCC filed a notice of inquiry to consider the issues related to the role of the OCC and Oklahoma regulated companies in addressing the security of the utility system infrastructure and key assets. On March 4, 2004, the OCC deliberated the notice of inquiry and directed the OCC Staff to file a rulemaking proceeding for each utility industry regarding security of the utility system infrastructure and key assets. On August 27, 2004, the OCC Staff filed a Notice of Proposed Rulemaking. The first technical conference was held on September 23, 2004 and written comments were filed by all the parties on October 1, 2004. A second technical conference was held on October 21, 2004 and a hearing is currently scheduled for December 3, 2004.

Cogeneration Credit Rider

On September 17, 2004, OG&E filed an application and testimony with the OCC requesting a cogeneration credit rider. The requested rider would reduce charges to customers because of decreasing cogeneration payments made by OG&E beginning January 2005. The cogeneration credit rider is necessary as amounts recovered from customers in base rates include historically higher cogeneration payments. OG&E's current cogeneration credit rider expires

December 31, 2004. On October 29, 2004, the OCC Staff and other parties filed responsive testimony. Hearings in this case are scheduled from November 15-17, 2004. An OCC order is expected by the end of 2004 regarding the new cogeneration credit rider.

Southwest Power Pool

OG&E is a member of the Southwest Power Pool ("SPP"), the regional reliability organization for all or parts of Oklahoma, Arkansas, Kansas, Louisiana, New Mexico, Mississippi, Missouri and Texas. OG&E participated with the SPP in the development of regional transmission tariffs and executed an Agency Agreement with the SPP to facilitate interstate transmission operations within this region in 1998. In October 2003, the SPP filed an application with the FERC seeking authority to form a regional transmission organization ("RTO"). On February 10, 2004, the FERC conditionally approved the SPP's application. The SPP must meet certain conditions before it may commence operations as an RTO. On April 27, 2004, the SPP Board of Directors took actions to meet the conditions to satisfy the FERC requirement for formal approval of the RTO. The SPP compliance filing at the FERC was made on May 3, 2004. In response to a subsequent FERC order on July 2, 2004, the SPP made a compliance filing on August 6, 2004 stating that all requirements had been met to achieve RTO status. In a FERC order dated October 1, 2004, the FERC accepted the SPP's compliance filing and the SPP was granted RTO status, subject to the SPP submitting a further compliance filing, within 30 days. On November 1, 2004, the SPP made a compliance filing as required under the October 1 FERC order. Also, on November 1, the SPP filed a request for rehearing of the FERC's October 1 order.

FERC Standards of Conduct

On November 25, 2003, the FERC issued new rules regulating the relationships between electric and natural gas transmission providers, as defined in the rules, and those entities' merchant personnel and energy affiliates. The new rules will replace the existing rules governing these relationships. The new rules expand the definition of "affiliate" and further limit communications between transmission providers and those entities' merchant personnel and energy affiliates.

In February 2004, OG&E and Enogex submitted plans and schedules to the FERC which detail the necessary actions to be in compliance with these new rules and expected that their initial costs to comply with the final rules would not exceed $1.6 million in 2004. On April 16, 2004 and August 2, 2004, the FERC issued orders on rehearing in which the FERC largely rejected requests to revise its November 25 final rule. However, the FERC did extend the compliance date until September 22, 2004 and did clarify certain aspects of the rule. OG&E and Enogex believe that they have taken the necessary actions to comply with the new rules and estimate that the initial costs of compliance incurred in the first nine months of 2004 were less than $0.5 million and the recurring cost of compliance in future years is expected to be immaterial to OGE Energy Corp.

On September 21, 2004, Ozark filed a request for clarification of the FERC's Order 2004 regulations to permit Ozark to share a common gas control group with its energy affiliates.

Granting the request would eliminate the need for Ozark to establish a separate gas control group. Ozark does not know when the FERC will act on the request for clarification.

Department of Energy Blackout Report

On April 6, 2004, the U.S. Department of Energy issued its final report regarding the August 14, 2003 electric blackout in the eastern United States, which did not have an adverse affect on OG&E's electric system. The report recommends a number of specific changes to current statutes, rules or practices in order to improve the reliability of the infrastructure used to transmit electric power. The recommendations include the establishment of mandatory reliability standards and financial penalties for noncompliance. On April 14, 2004, the FERC issued a policy statement requiring electric utilities, including OG&E, to submit a report on vegetation management practices and indicating the FERC's intent to make North American Electric Reliability Council reliability standards mandatory. On June 17, 2004, OG&E filed its report on vegetation management practices with the FERC. During 2004, OG&E has spent less than $0.2 million related to the implementation of blackout report recommendations. Implementation of the blackout report recommendations and the FERC policy statement could increase future transmission costs, but the extent of the increased costs is not known at this time.

Redbud Tariff Filing

On March 5, 2004, Redbud Energy LP ("Redbud") filed a rate schedule with the FERC in Docket No. ER04-622-000 under which Redbud proposed to charge OG&E a rate for transmission service Redbud alleges it provides to OG&E over certain facilities that Redbud constructed to connect its generation facility to the OG&E transmission grid. Redbud claims that the facilities cost approximately $19.3 million, and seeks to recover this amount from OG&E over a 60-month period. Also on March 5, 2004, Redbud filed an application with the FERC in Docket No. EG04-38-000 asking the FERC to rule that Redbud can charge OG&E this fee for transmission service and remain an exempt wholesale generator under Section 32 of the Public Utility Holding Company Act of 1935. OG&E opposed Redbud's filings in the two dockets on the grounds that Redbud is not entitled to impose such a transmission rate, and that the imposition of such a rate is inconsistent with Redbud's status as an exempt wholesale generator. On May 4, 2004, the FERC issued an order rejecting Redbud's proposed rate schedule. Redbud has since asked the FERC to rehear and reverse its May 4 order rejecting Redbud's filing. At this time, OG&E does not know when the FERC will rule on Redbud's request for rehearing. On November 1, 2004, the FERC issued an order denying Redbud's request for rehearing. Redbud has 60 days to file a petition for review with the FERC.

State Legislative Initiatives

Oklahoma

As previously reported, the Oklahoma legislature originally adopted the Electric Restructuring Act of 1997 (the “1997 Act”) to provide retail customers in Oklahoma with a choice of their electric supplier. The scheduled start date for customer choice has been indefinitely postponed. In the 2003 legislative session, attempts to repeal the 1997 Act were

initiated, but the session ended without repeal of the 1997 Act. It is unknown at this time whether the 1997 Act will be repealed.

In the 2004 legislative session, legislation was enacted requiring a study to determine the feasibility of providing investor-owned utilities an incentive to enter into purchase power agreements in Oklahoma by allowing the utilities to earn a return on purchased power. The study committee held its first meeting in late August and will continue holding two meetings a month through November. At the conclusion of the meetings, a final report with any recommendations will be filed with the legislature in January 2005.

Arkansas

In April 1999, Arkansas passed a law (the “Restructuring Law”) calling for restructuring of the electric utility industry at the retail level. The Restructuring Law, which had initially targeted customer choice of electricity providers by January 1, 2002, was repealed in March 2003 before it was implemented. As part of the repeal legislation, electric public utilities were permitted to recover transition costs. OG&E incurred approximately $2.4 million in transition costs necessary to carry out its responsibilities associated with efforts to implement retail open access. On January 20, 2004, the APSC issued an order which authorized OG&E to recover approximately $1.9 million in transition costs over an 18-month period beginning February 2004.

In the 2003 legislative session, legislation was enacted requiring a study relating to the restructuring of the electric utility industry at the industrial level to provide customer choice of electricity providers for large customers. A roundtable discussion regarding the study was held on July 22, 2004 and comments were filed on August 20, 2004. The APSC released the report on September 30, 2004 and the Insurance and Commerce Committee heard the issue on October 20, 2004. The commissioners concluded that circumstances in the current electric generation market have not changed sufficiently since adoption of Act 204 (The Electric Utility Regulatory Reform Act of 2003) to be able to structure a large user access program that would produce economic benefits for large users while also ensuring no cost-shifting or net cost increases to remaining customers. The commissioners also concluded that there are no clear economic benefits, and more likely economic harm, that would result from moving forward with the large user access program concept at this time.

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, 2003.

	September 30, 2004		December 31, 2003	
(In millions)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Price Risk Management Assets				
Energy Trading Contracts	**$ 163.1**	**$ 163.1**	$ 67.2	$ 67.2
Interest Rate Swaps	**9.3**	**9.3**	7.6	7.6
Price Risk Management Liabilities				
Energy Trading Contracts	**$ 174.3**	**$ 174.3**	$ 51.4	$ 51.4
Interest Rate Swaps	**4.2**	**4.2**	---	---
Long-Term Debt				
Senior Notes	**$ 711.9**	**$ 766.3**	$ 571.8	$ 611.8
Enogex Notes	**519.6**	**562.2**	576.0	674.7

The carrying value of the financial instruments on the Condensed Consolidated Balance Sheets not otherwise discussed above approximates fair value except for long-term debt which is valued at the carrying amount. The valuation of the Company’s interest rate swaps and energy trading contracts was determined 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.

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

The operations of the Natural Gas Pipeline segment are conducted through Enogex Inc. and its subsidiaries ("Enogex") and consist of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing of natural gas. Enogex's focus is to utilize its gathering, processing, transportation and storage capacity to execute physical, financial and service transactions to capture revenues across different commodities, locations or time periods. The vast majority of Enogex's natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. Through a 75 percent interest in the NOARK Pipeline System Limited Partnership ("NOARK"), Enogex also owns a controlling interest in and operates the Ozark Gas Transmission System ("Ozark"), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. During the third quarter of 2004, Enogex entered into a joint venture arrangement with a third party and contributed certain of its natural gas compression assets to use in the joint venture, whose primary business focus will be the rental of compression assets. Enogex created a wholly-owned limited liability company, Enogex Compression Company, LLC ("Enogex Compression"), to act as the participating entity in the joint venture. Enogex Compression holds a majority ownership in the joint venture and the third party acts as the manager and conducts the daily operations of the joint venture. Enogex Compression has been consolidated in the Company's financial statements with a minority interest recorded.

Forward-Looking Statements

Except for the historical statements contained herein, the matters discussed in the following discussion and analysis, including the discussion in "Outlook", are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate", "believe", "estimate", "expect", "intend", "objective", "plan", "possible", "potential" 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, 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; federal or state legislation and regulatory decisions and initiatives that affect cost and investment recovery, have an impact on rate structures and affect the speed and degree to which competition enters the Company's markets; changes in accounting standards, rules or guidelines; creditworthiness of suppliers, customers and other contractual parties; the higher degree of risk associated with the Company's nonregulated business compared with the Company's regulated utility business; and other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission including Exhibit 99.01 to the Company's Form 10-K for the year ended December 31, 2003.

Overview

General

The following discussion and analysis presents factors which affected the Company's consolidated results of operations for the three and nine months ended September 30, 2004 as compared to the same period in 2003 and the Company's consolidated financial position at September 30, 2004. The following information should be read in conjunction with the Condensed Consolidated Financial Statements and Notes thereto and the Company's Form 10-K for the year ended December 31, 2003. Known trends and contingencies of a material nature are discussed to the extent considered relevant.

In the first quarter of 2003, Enogex sold its interests in certain gas gathering and processing assets that were owned by Enogex through its interest in the NuStar Joint Venture ("NuStar"). As required by accounting principles generally accepted in the United States, these dispositions have been reported as discontinued operations for the three and nine months ended September 30, 2004 and 2003 in the Condensed Consolidated Financial Statements.

Summary of Operating Results

Quarter ended September 30, 2004 as compared to quarter ended September 30, 2003

The Company reported net income of approximately $94.6 million, or $1.07 per diluted share, as compared to approximately $99.5 million, or $1.20 per diluted share, for the three months ended September 30, 2004 and 2003, respectively. The decrease in net income during the three months ended September 30, 2004 as compared to the same period in 2003 was primarily due to cooler weather in OG&E's service territory, lower gross margins on revenues ("gross margin") in Enogex's transportation and storage business and Enogex's marketing business, an impairment charge and higher operating expenses at Enogex. These decreases were partially offset by higher gross margins in Enogex's gathering and processing business, lower

operating expenses at OG&E, a gain from the sale of assets, lower interest expenses and lower income tax expense. The Company's results of operations for the three months ended September 30, 2003 include a loss of approximately $1.8 million, or $0.02 per diluted share, from the discontinued operations discussed below. There were no discontinued operations for the three months ended September 30, 2004. See "Results of Operations – Enogex – Discontinued Operations" below for a further discussion.

OG&E reported net income of approximately $91.3 million, or $1.03 per diluted share of the Company's common stock, as compared to approximately $95.1 million, or $1.15 per diluted share, for the three months ended September 30, 2004 and 2003, respectively. The decrease in net income at OG&E during the three months ended September 30, 2004 as compared to the same period in 2003 was primarily attributable to lower gross margins due to cooler weather in OG&E's service territory partially offset by a gain from the sale of assets, lower operating expenses, lower interest expenses and lower income tax expense.

Enogex's operations, including discontinued operations, reported net income of approximately $6.3 million, or $0.07 per diluted share of the Company's common stock, as compared to approximately $8.4 million, or $0.10 per diluted share, for the three months ended September 30, 2004 and 2003, respectively. The decrease in net income at Enogex during the three months ended September 30, 2004 as compared to the same period in 2003 was primarily attributable to lower gross margins in Enogex's transportation and storage business from, among other things, a reclassification of contractual revenues to the gathering and processing business in 2004 and mark-to-market timing losses on natural gas storage inventory, lower gross margins in Enogex's marketing business from, among other things, mark-to-market timing losses on natural gas storage inventory, an impairment charge and higher operating expenses. These decreases were partially offset by higher gross margins in Enogex's gathering and processing business from, among other things, revenue improvements generated from the negotiation of both new contracts and replacement contracts at better terms that resulted in increases in gathering fees and reductions in the purchase price of gas and an overall favorable business environment coupled with higher commodity prices, lower interest expenses and lower income tax expense.

As stated above, Enogex's interest in NuStar has been reported as discontinued operations for the three months ended September 30, 2003 in the Condensed Consolidated Financial Statements as these assets have been sold. There were no discontinued operations for the three months ended September 30, 2004. The Company's results of operations for the three months ended September 30, 2003 include a loss of approximately $1.8 million, or $0.02 per diluted share, from the discontinued operations discussed above. This change was attributable to the sale of NuStar in the first quarter of 2003 in addition to a final accounting charge recorded in the third quarter 2003. See "Results of Operations – Enogex – Discontinued Operations" below for a further discussion.

During the three months ended September 30, 2004, Enogex had a reduction to net income of approximately $2.2 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex's business, including an impairment charge of approximately $5.1 million partially offset by income tax adjustments of approximately $1.6 million, authorized recovery of previously under recovered fuel of

approximately $1.2 million and a gain on the sale of Enogex compression and processing assets of approximately $0.1 million. During the three months ended September 30, 2003, Enogex had an increase in net income of approximately $1.5 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex's business, including authorized recovery of previously under recovered fuel of approximately $3.3 million partially offset by a loss from discontinued operations of approximately $1.8 million.

The results of the holding company reflect a loss of approximately $0.03 per diluted share and $0.05 per diluted share for the three months ended September 30, 2004 and 2003, respectively, primarily due to lower interest expenses.

Earnings per share for the three months ended September 30, 2004 as compared to the same period in 2003 were affected by a higher amount of common stock outstanding from the Company's equity issuance in August 2003 and the issuance of common stock in 2003 and 2004 pursuant to the Company's Automatic Dividend Reinvestment and Stock Purchase Plan ("DRIP").

Nine months ended September 30, 2004 as compared to nine months ended September 30, 2003

The Company reported net income of approximately $143.8 million, or $1.63 per diluted share, as compared to approximately $131.4 million, or $1.63 per diluted share, for the nine months ended September 30, 2004 and 2003, respectively. The increase in net income during the nine months ended September 30, 2004 as compared to the same period in 2003 was primarily due to higher gross margins in Enogex's gathering and processing business, lower operating expenses at OG&E, a gain from the sale of assets, lower interest expenses and lower income tax expense. Also contributing to the increase in net income for the nine months ended September 30, 2004 was a loss recorded during the first quarter of 2003 related to a cumulative effect of a change in accounting principle of which there is not a comparable item recorded in the nine months ended September 30, 2004. These increases were partially offset by cooler weather in OG&E's service territory, lower gross margins in Enogex's transportation and storage business and Enogex's marketing business, an impairment charge and higher operating expenses at Enogex. The Company's results of operations for the nine months ended September 30, 2004 and 2003, respectively, include income of approximately $0.4 million, or less than $0.01 per diluted share, and a loss of approximately $0.5 million, or $0.01 per diluted share, from the discontinued operations discussed above. See "Results of Operations – Enogex – Discontinued Operations" below for a further discussion.

OG&E reported net income of approximately $121.7 million, or $1.38 per diluted share, as compared to approximately $119.7 million, or $1.49 per diluted share, for the nine months ended September 30, 2004 and 2003, respectively. The increase in net income at OG&E during the nine months ended September 30, 2004 as compared to the same period in 2003 was primarily attributable to a gain from the sale of assets, lower operating expenses, lower interest expenses and lower income tax expense partially offset by lower gross margins due to cooler weather in OG&E's service territory.

Enogex's operations, including discontinued operations, reported net income of approximately $30.6 million, or $0.35 per diluted share, as compared to approximately $21.6 million, or $0.27 per diluted share, for the nine months ended September 30, 2004 and 2003, respectively. The increase in net income at Enogex during the nine months ended September 30, 2004 as compared to the same period in 2003 was primarily attributable to higher gross margins in Enogex's gathering and processing business from, among other things, revenue improvements generated from the negotiation of both new contracts and replacement contracts at better terms that resulted in increases in gathering fees and reductions in the purchase price of gas and an overall favorable business environment coupled with higher commodity prices, lower interest expenses and lower income tax expense. Also contributing to the increase in net income for the nine months ended September 30, 2004 was a loss recorded during the first quarter of 2003 related to a cumulative effect of a change in accounting principle of which there is not a comparable item recorded in the nine months ended September 30, 2004. These increases were partially offset by lower gross margins in Enogex's transportation and storage business from, among other things, a reclassification of contractual revenues to the gathering and processing business in 2004 and mark-to-market timing losses on natural gas storage inventory, lower gross margins in Enogex's marketing business from, among other things, mark-to-market timing losses on natural gas storage inventory, an impairment charge and higher operating expenses.

As stated above, Enogex's interest in NuStar has been reported as discontinued operations for the nine months ended September 30, 2004 and 2003 in the Condensed Consolidated Financial Statements as these assets have been sold. The Company's results of operations for the nine months ended September 30, 2004 and 2003, respectively, include income of approximately $0.4 million, or less than $0.01 per diluted share, and a loss of approximately $0.5 million, or $0.01 per diluted share, from the discontinued operations discussed above. The positive results for 2004 are attributable to funds received in the first quarter of 2004 related to an overpayment of natural gas purchases in a prior period. See "Results of Operations – Enogex – Discontinued Operations" below for a further discussion.

During the nine months ended September 30, 2004, Enogex had an increase in net income of approximately $4.2 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex's business, including authorized recovery of previously under recovered fuel that provided a positive earnings contribution of approximately $3.9 million and the Oklahoma investment tax credit that provided a positive earnings contribution of approximately $2.0 million. In addition, a gain on the sale of Enogex compression and processing assets of approximately $1.8 million, income tax adjustments of approximately $1.6 million and income from discontinued operations of approximately $0.4 million provided positive earnings contributions. These increases were partially offset by an impairment charge of approximately $5.1 million and approximately $0.4 million due to other miscellaneous items. During the nine months ended September 30, 2003, Enogex had an increase in net income of approximately $7.1 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex's business, including authorized recovery of previously under recovered fuel of approximately $5.6 million, the gain on the sale of assets of approximately $2.6 million and a prior period adjustment of approximately $1.1 million. These increases were partially offset by an income tax adjustment

of approximately $1.7 million and a loss from discontinued operations of approximately $0.5 million.

The results of the holding company reflect a loss of approximately $0.10 per diluted share and $0.13 per diluted share for the nine months ended September 30, 2004 and 2003, respectively, primarily due to lower interest expenses.

Earnings per share for the nine months ended September 30, 2004 as compared to the same period in 2003 was affected by a higher amount of common stock outstanding from the Company's equity issuance in August 2003 and the issuance of common stock in 2003 and 2004 pursuant to the Company's DRIP.

Regulatory Matters and Plant Acquisition

In November 2002, the OCC issued an order containing provisions of an agreed-upon settlement of OG&E's rate case. The terms of this settlement included, among other things, a $25.0 million annual reduction in electric rates and a requirement for OG&E to acquire 400 megawatts ("MW") of electric generation. On July 9, 2004, OG&E completed its acquisition of a 77 percent interest in the 520 MW McClain Plant. The purchase price was approximately $160.0 million. OG&E temporarily funded the McClain Plant acquisition with short-term borrowings from the Company. On August 4, 2004, OG&E issued $140.0 million of long-term debt to replace these short-term borrowings. For additional information regarding the McClain Plant acquisition and related regulatory matters, see Note 17 of Notes to Condensed Consolidated Financial Statements.

Outlook

For 2004, the Company expects consolidated earnings to be near $1.60 per share. This estimate recognizes the impact of mild summer weather at OG&E which had cooling degree days 14 percent below normal during the third quarter. The mild third quarter weather, as compared to normal, negatively impacted OG&E's revenues by approximately $20 million, or $0.14 per share. OG&E's earnings range is now expected to be between $111 million and $115 million, or $1.26 to $1.30 per share. In addition, Enogex has recorded an impairment charge of approximately $8.6 million in the third quarter of 2004 related to notification received from a customer that a transportation agreement involving four of Enogex's non-contiguous pipeline asset segments located in west Texas and used to serve the customer's power plants would be terminated effective December 31, 2004. In connection with the preparation of these financial statements, Enogex performed an evaluation on these assets and concluded that an impairment charge needed to be recorded. Enogex still expects to meet its previous 2004 earnings guidance of between $40 million and $44 million, or $0.45 to $0.50 per share. The 2004 earnings guidance for the holding company remains unchanged at a projected loss of approximately $13 million to $14 million, or $0.15 to $0.16 per share and includes approximately $5.9 million of additional interest expense for unamortized debt issuance costs associated with calling the trust preferred securities.

For 2005, the Company's earnings guidance is $136 million to $145 million of net income, or $1.50 to $1.60 per share, assuming approximately 90.4 million average diluted shares outstanding. OG&E's contribution to consolidated earnings is projected to be $108 million to $112 million, or $1.19 to $1.23 per share. OG&E assumes that margin growth approximating two percent will be more than offset by increased operating expenses and higher interest costs associated with the acquisition of the McClain Plant and capital expenditures for investment in OG&E's generation, transmission and distribution system. The guidance further assumes no change in base rates and normal weather. OG&E expects to file a rate case by mid-year 2005 to recover, among other things, its investment in, and the operating expenses of, the McClain Plant and expects new approved rates to be in effect by the first quarter of 2006. The earnings guidance also assumes a recovery of the costs associated with the Enogex natural gas transportation and storage services at a level consistent with a recent recommendation by the administrative law judge overseeing this proceeding. On October 22, 2004, the administrative law judge overseeing the proceeding recommended approximately $41.9 million annual recovery with OG&E refunding to its customers any amounts collected in excess of this amount. If this recommendation is ultimately accepted, OG&E believes its refund obligation will be approximately $6.1 million, which the Company does not believe is material in light of previously established reserves. An OCC order in this case is expected by the end of 2004.

For 2005, Enogex projects earnings of between $39 million and $43 million, or $0.43 to $0.48 per share. Enogex forecasts lower margins due to assumed lower commodity spreads of $1.53 per Million British thermal unit ("MMBtu") in 2005 as compared to $2.21 per MMBtu in 2004. These lower margins also assume lower average natural gas liquids prices of $0.71 per gallon in 2005 as compared to $0.78 per gallon in 2004. These lower commodity prices are only partially offset by higher gross margins in the marketing business, lower operating expenses due to the $8.6 million impairment charge recorded in the third quarter of 2004 and lower interest expenses due to the retirement of long-term debt.

For 2005, the holding company, which primarily has interest expense but no operating revenue, projects a loss between $6 million and $8 million, or $0.07 to $0.09 per share. The decrease in the projected loss as compared to 2004 is primarily due to lower interest expenses associated with the retirement of $200 million of trust preferred securities on October 15, 2004.

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 determined or included in the 2004 or 2005 earnings guidance.

Results of Operations

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(In millions, except per share data)	**2004**	2003	**2004**	2003
Operating income	**$ 162.6**	$ 187.3	**$ 275.8**	$ 291.6
Net income	**$ 94.6**	$ 99.5	**$ 143.8**	$ 131.4
Basic average common shares outstanding	**87.8**	82.4	**87.6**	80.1

Diluted average common shares outstanding		**88.3**		82.7		**88.1**		80.4
Basic earnings per average common share	**$**	**1.08**	$	1.21	**$**	**1.64**	$	1.64
Diluted earnings per average common share	**$**	**1.07**	$	1.20	**$**	**1.63**	$	1.63
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 was approximately $162.6 million and $187.3 million for the three months ended September 30, 2004 and 2003, respectively. Operating income was approximately $275.8 million and $291.6 million for the nine months ended September 30, 2004 and 2003, respectively. These amounts exclude the results of NuStar, which as explained above, was sold in the first quarter of 2003 and which is reported as discontinued operations. See "Enogex – Discontinued Operations" below for a further discussion.

Operating Income (Loss) by Business Segment

	Three Months Ended September 30,				Nine Months Ended September 30,			
(In millions)		**2004**		2003		**2004**		2003
OG&E (Electric Utility)	**$**	**147.4**	$	160.8	**$**	**207.1**	$	218.2
Enogex (Natural Gas Pipeline) (A)		**15.4**		26.5		**68.7**		73.4
Other Operations (B)		**(0.2)**		---		---		---
Consolidated operating income	**$**	**162.6**	$	187.3	**$**	**275.8**	$	291.6

(A) Excludes discontinued operations.
(B) Other Operations primarily includes unallocated corporate expenses.

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)		**2004**		2003		**2004**		2003
Operating revenues	**$**	**535.9**	$	540.3	**$**	**1,251.7**	$	1,230.9
Fuel		**220.1**		181.9		**490.9**		448.8
Purchased power		**60.8**		84.2		**216.4**		218.2
Gross margin on revenues		**255.0**		274.2		**544.4**		563.9
Other operating and maintenance		**65.7**		71.5		**208.7**		218.3
Depreciation		**30.2**		29.9		**92.4**		91.7
Taxes other than income		**11.7**		12.0		**36.2**		35.7
Operating income	**$**	**147.4**	$	160.8	**$**	**207.1**	$	218.2
Operating revenues by classification								
Residential	**$**	**218.7**	$	243.2	**$**	**495.3**	$	508.5
Commercial		**134.2**		131.4		**309.7**		301.6
Industrial		**100.4**		86.8		**254.0**		224.9
Public authorities		**53.3**		49.1		**124.4**		115.4
Sales for resale		**17.9**		17.5		**44.3**		45.6
Other		**11.2**		11.4		**23.5**		31.2
System sales revenues		**535.7**		539.4		**1,251.2**		1,227.2
Off-system sales revenues		**0.2**		0.9		**0.5**		3.7
Total operating revenues	$	**535.9**	$	540.3	$	**1,251.7**	$	1,230.9
MWH (A) sales by classification (in millions)								
Residential		**2.6**		3.0		**6.3**		6.6
Commercial		**1.7**		1.7		**4.4**		4.5
Industrial		**1.8**		1.7		**5.2**		5.0
Public authorities		**0.7**		0.8		**2.0**		2.0
Sales for resale		**0.4**		0.4		**1.1**		1.2
System sales		**7.2**		7.6		**19.0**		19.3
Off-system sales		---		---		---		0.1

Total sales	**7.2**	7.6	**19.0**	19.4
Number of customers	**733,243**	724,549	**733,243**	724,549
Average cost of energy per KWH (B) - cents				
Fuel	**3.244**	2.759	**2.891**	2.607
Fuel and purchased power	**3.635**	3.293	**3.462**	3.227
Degree days (C)				
Heating				
Actual	**---**	22	**1,962**	2,279
Normal	**29**	29	**2,247**	2,228
Cooling				
Actual	**1,120**	1,325	**1,760**	1,803
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 degrees days, with each degree of difference equaling one cooling degree day. If the calculated average is below 65 degrees, than 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, 2004 as compared to quarter ended September 30, 2003

OG&E’s operating income for the three months ended September 30, 2004 decreased approximately $13.4 million or 8.3 percent as compared to the same period in 2003. The decrease in operating income was primarily attributable to cooler weather in OG&E’s service territory and lower margins related to sales to wholesale customers. These decreases were partially offset by growth in OG&E’s service territory, the timing of fuel recoveries and lower operating expenses.

Gross margin, which is operating revenues less cost of goods sold, was approximately $255.0 million for the three months ended September 30, 2004 as compared to approximately $274.2 million during the same period in 2003, a decrease of approximately $19.2 million or 7.0 percent. The gross margin decreased approximately $21.9 million due to cooler weather in OG&E’s service territory and approximately $1.1 million due to lower margins related to sales to wholesale customers primarily resulting from reduced sales of power under a new wholesale contract with an existing customer. These decreases were partially offset by an increase of approximately $2.2 million due to growth in OG&E’s service territory and an increase of approximately $1.9 million due to the timing of fuel recoveries.

Cost of goods sold for OG&E consists of fuel used in electric generation and purchased power. Fuel expense was approximately $220.1 million for the three months ended September 30, 2004 as compared to approximately $181.9 million during the same period in 2003, an increase of approximately $38.2 million or 21.0 percent. The increase was due to an increase in the average cost of fuel per kwh, primarily due to higher natural gas prices, despite lower mwh sales. Purchased power costs were approximately $60.8 million for the three months ended September 30, 2004 as compared to approximately $84.2 million during the same period in 2003, a decrease of approximately $23.4 million or 27.8 percent. The decrease was primarily due to OG&E’s acquisition of the McClain Plant in July 2004, lower volumes of purchased power and the termination of a power purchase contract in December 2003.

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component included in the cost-of-service for ratemaking, are passed through to OG&E’s customers through automatic fuel adjustment clauses. While the regulatory mechanisms for recovering fuel costs differ in Oklahoma, Arkansas and the FERC, in each jurisdiction the costs are passed through to customers and are intended to provide neither an ultimate benefit nor detriment to OG&E. The automatic fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC. The OCC, the APSC and the FERC have authority to review the appropriateness of gas transportation charges or other fees OG&E pays to Enogex. See Note 17 of Notes to Condensed Consolidated Financial Statements for a discussion of current proceedings at the OCC regarding OG&E’s gas transportation and storage contract with Enogex.

Operating and maintenance expenses decreased approximately $5.8 million or 8.1 percent for the three months ended September 30, 2004 as compared to the same period in 2003. This decrease was primarily due to a decrease of approximately $3.8 million in pension and benefit expense and a decrease of approximately $1.7 million in salaries and wages expense during the

three months ended September 30, 2004 as compared to the same period in 2003 due to more projects on which the costs are capitalized and are not being expensed currently. A contributing factor to the overall decrease in operating and maintenance expense was that a number of OG&E employees provided assistance for hurricane restoration efforts in the southeastern United States and, as a result, were not available for OG&E projects. Also contributing to the decrease was a decrease of approximately $2.0 million in corporate allocations due to over allocations during the first six months of 2004. These decreases in operating and maintenance expense were partially offset by an increase of approximately $3.3 million in outside services expense primarily due to Southwest Power Pool (“SPP”) membership fees. Depreciation expense increased approximately $0.3 million or 1.0 percent for the three months ended September 30, 2004 as compared to the same period in 2003 primarily due to a higher level of depreciable plant. Taxes other than income decreased approximately $0.3 million or 2.5 percent for the three months ended September 30, 2004 as compared to the same period in 2003 primarily due to a decrease of approximately $0.2 million in ad valorem taxes.

Nine months ended September 30, 2004 as compared to nine months ended September 30, 2003

OG&E’s operating income for the nine months ended September 30, 2004 decreased approximately $11.1 million or 5.1 percent as compared to the same period in 2003. The decrease in operating income was primarily attributable to cooler weather in OG&E’s service territory, lower margins related to sales to wholesale customers and the timing of fuel recoveries. These decreases were partially offset by growth in OG&E’s service territory and lower operating expenses.

Gross margin was approximately $544.4 million for the nine months ended September 30, 2004 as compared to approximately $563.9 million during the same period in 2003, a decrease of approximately $19.5 million or 3.5 percent. The gross margin decreased approximately $23.5 million due to cooler weather in OG&E's service territory, approximately $2.6 million due to lower margins related to sales to wholesale customers primarily resulting from reduced sales of power under a new wholesale contract with an existing customer and approximately $0.6 million due to the timing of fuel recoveries. These decreases were partially offset by an increase of approximately $7.5 million due to growth in OG&E's service territory.

Fuel expense was approximately $490.9 million for the nine months ended September 30, 2004 as compared to approximately $448.8 million during the same period in 2003, an increase of approximately $42.1 million or 9.4 percent. The increase was due to an increase in the average cost of fuel per kwh, primarily due to higher natural gas prices, despite lower mwh sales. Purchased power costs were approximately $216.4 million for the nine months ended September 30, 2004 as compared to approximately $218.2 million during the same period in 2003, a decrease of approximately $1.8 million or 0.8 percent. The decrease was primarily due to OG&E's acquisition of the McClain Plant in July 2004 and the termination of a power purchase contract in December 2003.

Operating and maintenance expenses decreased approximately $9.6 million or 4.4 percent for the nine months ended September 30, 2004 as compared to the same period in 2003. This

decrease was primarily due to a decrease of approximately $6.5 million in pension and benefit expense and a decrease of approximately $5.1 million in salaries and wages expense during the nine months ended September 30, 2004 as compared to the same period in 2003 due to more projects on which the costs are capitalized and are not being expensed currently. A contributing factor to the overall decrease in operating and maintenance expense was that a number of OG&E employees provided assistance for hurricane restoration efforts in the southeastern United States and, as a result, were not available for OG&E projects. Also contributing to the decrease was a decrease of approximately $2.1 million in corporate allocations primarily due to a decrease in depreciation expense allocated to OG&E related to one of the Company's systems being fully depreciated in 2003 and a decrease of approximately $0.6 million in property insurance costs. These decreases in operating and maintenance expense were partially offset by an increase of approximately $4.1 million in outside services expense primarily due to SPP membership fees and approximately $2.2 million in bad debt expense. Depreciation expense increased approximately $0.7 million or 0.8 percent for the nine months ended September 30, 2004 as compared to the same period in 2003 primarily due to a higher level of depreciable plant. Taxes other than income increased approximately $0.5 million or 1.4 percent for the nine months ended September 30, 2004 as compared to the same period in 2003 primarily due to an increase of approximately $0.4 million in ad valorem taxes.

Enogex – Continuing Operations

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Dollars in millions)	**2004**	2003	**2004**	2003
Operating revenues	**$ 816.6**	$ 533.3	**$ 2,341.3**	$ 1,786.1
Gas and electricity purchased for resale	**727.9**	460.0	**2,076.7**	1,556.3
Natural gas purchases - other	**23.3**	9.1	**65.3**	42.9
Gross margin on revenues	**65.4**	64.2	**199.3**	186.9
Other operating and maintenance	**25.4**	22.1	**73.8**	66.9
Depreciation	**11.7**	11.0	**34.6**	33.2
Impairment of assets	**8.6**	---	**8.6**	---
Taxes other than income	**4.3**	4.6	**13.6**	13.4
Operating income	**$ 15.4**	$ 26.5	**$ 68.7**	$ 73.4
New well connects	**77**	57	**194**	167
Gathered volumes - TBtu/d (A)	**1.02**	0.95	**1.01**	0.99
Incremental transportation volumes - TBtu/d	**0.53**	0.47	**0.49**	0.46
Total throughput volumes - TBtu/d	**1.55**	1.42	**1.50**	1.45
Natural gas processed - Mmcf/d (B)	**479**	541	**486**	480
Natural gas liquids produced (keep whole) - million gallons	**73**	50	**176**	150
Natural gas liquids produced (POL and fixed-fee) - million gallons	**4**	5	**12**	13
Total natural gas liquids produced - million gallons	**77**	55	**188**	163
Average sales price per gallon	**$ 0.727**	$ 0.582	**$ 0.693**	$ 0.591

(A) Trillion British thermal units per day.
(B) Million cubic feet per day.

Quarter ended September 30, 2004 as compared to quarter ended September 30, 2003

Enogex's operating income for the three months ended September 30, 2004 decreased approximately $11.1 million or 41.9 percent as compared to the same period in 2003. The decrease was primarily attributable to lower gross margins in Enogex's transportation and storage business from, among other things, a reclassification of contractual revenues to the gathering and processing business in 2004 and mark-to-market timing losses on natural gas storage inventory, lower gross margins in Enogex's marketing business from, among other things, mark-to-market timing losses on natural gas storage inventory, an impairment charge and higher operating expenses. These decreases were partially offset by higher gross margins in Enogex's gathering and processing business from, among other things, revenue improvements generated from the negotiation of both new contracts and replacement contracts at better terms that resulted in increases in gathering fees and reductions in the purchase price of gas and an overall favorable business environment coupled with higher commodity prices. Enogex sold its interest in NuStar during the first quarter of 2003; accordingly this is reported as discontinued operations for the three months ended September 30, 2003 in the Condensed Consolidated Financial Statements. See "Enogex – Discontinued Operations" below for a further discussion.

Transportation and storage contributed approximately $33.2 million of Enogex's gross margin for the three months ended September 30, 2004 as compared to approximately $38.9 million during the same period in 2003, a decrease of approximately $5.7 million or 14.7 percent. Gross margins decreased approximately $3.5 million for the three months ended September 30, 2004 as compared to the same period in 2003 due to certain contractual revenues

recorded in transportation and storage in 2003 being recorded in gathering and processing in 2004. Gross margins also decreased approximately $2.6 million due to mark-to-market timing losses on natural gas storage inventory. Gross margins decreased approximately $2.3 million due to lower demand fees as a result of the Calpine Energy settlement and an increase in related demand fees recognized in the third quarter of 2003. Gross margins also decreased approximately $1.6 million due to the net change between fuel retained and fuel consumed. Partially offsetting these decreases in gross margin was an increase from higher storage revenues of approximately $1.9 million for the three months ended September 30, 2004 as compared to the same period in 2003. The increased storage revenues were mainly due to fees charged to certain customers for additional services in excess of the services previously contracted primarily due to cooler weather in which certain customers needed to inject more gas than anticipated. Gross margin increased by approximately $1.2 million due to a reduction in the imbalance collection reserve due to reserves for imbalances recorded in 2003. Gross margin also was positively impacted for the three months ended September 30, 2004 by increased crosshaul revenues of approximately $1.1 million reflecting increases in crosshaul margins and volumes.

Gathering and processing contributed approximately $38.7 million of Enogex's gross margin for the three months ended September 30, 2004 as compared to approximately $23.5 million during the same period in 2003, an increase of approximately $15.2 million or 64.7 percent. Gathering gross margins increased approximately $6.8 million for the three months ended September 30, 2004 as compared to the same period in 2003, of which approximately $3.5 million reflects the change in 2004 discussed above of recording certain contractual revenues in gathering and processing rather than in transportation and storage. Gross margins also increased due to revenue improvements generated from the negotiation of both new contracts and replacement contracts at better terms that resulted in increases in gathering fees and reductions in the purchase price of gas and an overall favorable business environment coupled with higher commodity prices. Processing gross margins increased approximately $8.4 million for the three months ended September 30, 2004 as compared to the same period in 2003. The increase reflects increased keep whole, percent of liquids and condensate margins due to favorable commodity prices and recording a default processing fee reserve during the three months ended September 30, 2003. There was no default processing fee reserve recorded during the three months ended September 30, 2004.

Marketing reduced Enogex's gross margin by approximately $6.5 million for the three months ended September 30, 2004 as compared to a contribution of approximately $1.8 million during the same period in 2003, a decrease of approximately $8.3 million. The decrease was primarily due to an increase of approximately $6.5 million in mark-to-market timing losses on natural gas storage inventory due to different pricing environments during the three months ended September 30, 2004 as compared to the same period in 2003. Also contributing to the decrease was a net decrease of approximately $3.2 million related to activity in the marketing portfolio and the exit from the power marketing business in 2004. These decreases also were partially offset by an increase in the gross margin resulting from a decrease in demand fees expense of approximately $1.4 million for storage services due to establishing new rates for the new storage season which began April 1.

Operating and maintenance expenses increased approximately $3.3 million or 14.9 percent for the three months ended September 30, 2004 as compared to the same period in 2003.

The increase is primarily due to an increase of approximately $1.5 million in outside services due to a study performed related to the integrity and safety of Enogex's pipeline, an increase in bad debt expense of approximately $0.8 million due to Enogex formerly recording bad debt expense on a case-by-case basis and now utilizing an allowance method as a percentage of Enogex sales, an increase in materials and supplies expense for repairs and maintenance of systems of approximately $0.6 million and an increase of approximately $0.4 million in payroll, benefits and pension expense due to hiring new employees, payment of overtime and salary increases. Depreciation expense increased approximately $0.7 million or 6.4 percent primarily due to a higher level of depreciable plant. Impairment of assets increased approximately $8.6 million or 100.0 percent for the three months ended September 30, 2004 as a result of recording an impairment charge during the third quarter of 2004 related to Enogex natural gas pipeline assets. During September 2004, Enogex received notification from a customer that a transportation agreement involving four of Enogex's non-contiguous pipeline asset segments located in west Texas and used to serve the customer's power plants would be terminated effective December 31, 2004. In connection with the preparation of these financial statements, Enogex performed an evaluation on these assets and concluded that an impairment charge needed to be recorded. The primary reason for this determination was that these four pipeline asset segments were originally built for the specific purpose of providing gas transmission service to this customers' four power plants that are now going to be shut down, and, as a result, other alternative commercial uses for these facilities are considered unlikely. Taxes other than income decreased approximately $0.3 million or 6.5 percent for the three months ended September 30, 2004 as compared to the same period in 2003 primarily due to a decrease of approximately $0.2 million in franchise taxes.

Nine months ended September 30, 2004 as compared to nine months ended September 30, 2003

Enogex's operating income for the nine months ended September 30, 2004 decreased approximately $4.7 million or 6.4 percent as compared to the same period in 2003. The decrease was primarily attributable to lower gross margins in Enogex's transportation and storage business from, among other things, a reclassification of contractual revenues to the gathering and processing business in 2004 and mark-to-market timing losses on natural gas storage inventory, lower gross margins in Enogex's marketing business from, among other things, mark-to-market timing losses on natural gas storage inventory, an impairment charge and higher operating expenses. These decreases were partially offset by a higher gross margins in Enogex's gathering and processing business from, among other things, revenue improvements generated from the negotiation of both new contracts and replacement contracts at better terms that resulted in increases in gathering fees and reductions in the purchase price of gas and an overall favorable business environment coupled with higher commodity prices. Enogex sold its interest in NuStar during the first quarter of 2003; accordingly this is reported as discontinued operations for the nine months ended September 30, 2004 and 2003 in the Condensed Consolidated Financial Statements. See "Enogex – Discontinued Operations" below for a further discussion.

Transportation and storage contributed approximately $97.1 million of Enogex's gross margin for the nine months ended September 30, 2004 as compared to approximately $101.8 million during the same period in 2003, a decrease of approximately $4.7 million or 4.6 percent. Gross margins decreased approximately $9.4 million due to certain contractual revenues recorded in transportation and storage in 2003 being recorded in gathering and processing in 2004. Gross margins also decreased approximately $3.7 million due to mark-to-market timing losses on natural gas storage inventory. Gross margins decreased approximately $2.4 million due to lower demand fees as a result of the Calpine Energy settlement and an increase in related demand fees recognized in the third quarter of 2003. These decreases were partially offset by an increase in gross margins of approximately $4.1 million from higher storage revenues for the nine months ended September 30, 2004 as compared to the same period in 2003. The increased storage revenues were mainly due to additional demand fees from the storage contract with OG&E, which was effective May 2003, in addition to fees charged to certain customers for additional services in excess of the services previously contracted primarily due to cooler weather in which certain customers needed to inject more gas than anticipated. Gross margins increased approximately $2.1 million from higher interruptible revenues and approximately $1.7 million in crosshaul revenues due to an increase in interruptible contract volumes and increased crosshaul margins and volumes. Gross margin increased by approximately $2.1 million due to the net change between fuel retained and fuel consumed. Gross margin also was favorably impacted by increased transportation revenues of approximately $0.7 million for the nine months ended September 30, 2004 from additional demand fees from the transportation contract with OG&E, which was effective May 2003.

Gathering and processing contributed approximately $102.6 million of Enogex's gross margin for the nine months ended September 30, 2004 as compared to approximately $67.0 million during the same period in 2003, an increase of approximately $35.6 million or 53.1 percent. Gathering gross margins increased approximately $23.0 million for the nine months ended September 30, 2004 as compared to the same period in 2003, of which approximately $9.4 million reflects the change in 2004 discussed above of recording certain contractual revenues in gathering and processing rather than in transportation and storage. Gross margins also increased due to revenue improvements generated from the negotiation of both new contracts and replacement contracts at better terms that resulted in increases in gathering fees and reductions in the purchase price of gas and an overall favorable business environment coupled with higher commodity prices. Processing gross margins increased approximately $12.6 million for the nine months ended September 30, 2004 as compared to the same period in 2003. The increase was primarily due to increased keep whole, percent of liquids and condensate margins due to favorable commodity prices and an expense reallocation due to field compressor fuel recorded in processing in 2003 being recorded in transportation and storage in 2004. These increases were partially offset by default processing fee revenue recorded during the nine months ended September 30, 2003. There was no default processing fee revenue recorded during the nine months ended September 30, 2004.

Marketing reduced Enogex's gross margin by approximately $0.4 million for the nine months ended September 30, 2004 as compared to a contribution of approximately $18.1 million during the same period in 2003, a decrease of approximately $18.5 million. Gross margin included gains from the sale of natural gas in storage of approximately $2.2 million and $10.2 million, respectively, during the nine months ended September 30, 2004 and 2003. The decrease in the gains of the sale of natural gas in storage was primarily due to Enogex recording approximately a $9.0 million pre-tax loss as a cumulative effect of a change in accounting principle in the first quarter of 2003 rather than this loss being included as a reduction of the

gross margin. The cumulative effect of a change in accounting principle was the result of accounting for certain energy contracts and natural gas in storage at the lower of cost or market rather than on a mark-to-market basis. See Note 2 of Notes to Condensed Consolidated Financial Statements for a further discussion. Also contributing to the decrease was an increase of approximately $7.3 million in mark-to-market timing losses on natural gas storage inventory due to different pricing environments during the nine months ended September 30, 2004 as compared to the same period in 2003. The gross margin was also negatively impacted by a net decrease of approximately $5.4 million related to activity in the marketing portfolio and the exit from the power marketing business in 2004. These decreases were also partially offset by an increase in the gross margin resulting from a decrease in demand fees expense of approximately $2.3 million for storage services due to establishing new rates for the new storage season which began April 1.

Operating and maintenance expenses increased approximately $6.9 million or 10.3 percent for the nine months ended September 30, 2004 as compared to the same period in 2003. The increase reflects higher allocations from the holding company of approximately $2.3 million due to a change in allocation methods, higher outside service costs of approximately $1.9 million due to a study performed related to the integrity and safety of Enogex's pipeline, an increase of approximately $1.8 million in payroll, benefit and pension expenses due to hiring new employees, payment of overtime and salary increases, higher materials and supplies expense for repairs and maintenance of systems of approximately $1.3 million and an increase in bad debt expense of approximately $1.0 million due to Enogex formerly recording bad debt expense on a case-by-case basis and now utilizing an allowance method as a percentage of Enogex sales. Depreciation expense increased approximately $1.4 million or 4.2 percent for the nine months ended September 30, 2004 as compared to the same period in 2003 primarily due to a higher level of depreciable plant. Impairment of assets increased approximately $8.6 million or 100.0 percent for the nine months ended September 30, 2004 as a result of recording an impairment charge during the third quarter of 2004 related to Enogex natural gas pipeline assets. During September 2004, Enogex received notification from a customer that a transportation agreement involving four of Enogex's non-contiguous pipeline asset segments located in west Texas and used to serve the customer's power plants would be terminated effective December 31, 2004. In connection with the preparation of these financial statements, Enogex performed an evaluation on these assets and concluded that an impairment charge needed to be recorded. The primary reason for this determination was that these four pipeline asset segments were originally built for the specific purpose of providing gas transmission service to this customers' four power plants that are now going to be shut down, and, as a result, other alternative commercial uses for these facilities are considered unlikely. Taxes other than income increased approximately $0.2 million or 1.5 percent for the nine months ended September 30, 2004 as compared to the same period in 2003 primarily due to an increase of approximately $0.4 million in ad valorem taxes and an increase of approximately $0.2 million in payroll taxes partially offset by a decrease of approximately $0.5 million in franchise taxes.

Consolidated Other Income and Expense, Interest Expense and Income Tax Expense

Other income includes, among other things, contract work performed by OG&E, non-operating rental income, gain on the sale of assets, minority interest income and miscellaneous non-operating income. Other income was approximately $5.2 million for the three months ended

September 30, 2004 as compared to approximately $0.3 million during the same period in 2003, an increase of approximately $4.9 million. The increase was primarily due to gains of approximately $3.0 million from the sale of OG&E's interests in its natural gas producing properties, approximately $0.6 million from the repurchase of outstanding heat pump loans and approximately $0.2 million on the sale of certain of Enogex's compression and processing assets during the three months ended September 30, 2004, in addition to approximately $0.8 million received related to a bankruptcy settlement from one of the Company's customers, partially offset by a decrease of approximately $0.2 million in the assets associated with the deferred compensation plan and retirement restoration plan.

Other income was approximately $10.9 million for the nine months ended September 30, 2004 as compared to approximately $7.0 million during the same period in 2003, an increase of approximately $3.9 million or 55.7 percent. In the first quarter of 2003, the Company recognized a pre-tax gain of approximately

$5.3 million related to the sale of approximately 29 miles of transmission lines of the Ozark pipeline. During the nine months ended September 30, 2004, the Company realized gains of approximately $3.0 million from the sale of OG&E's interests in its natural gas producing properties, approximately $3.0 million on the sale of certain of Enogex's compression and processing assets, approximately $0.6 million from the repurchase of outstanding heat pump loans and approximately $0.3 million from the sale of land near the Company's principal executive offices, in addition to an increase of approximately $0.8 million in the assets associated with the deferred compensation plan and retirement restoration plan and approximately $0.8 million received related to a bankruptcy settlement from one of the Company's customers.

Other expense includes, among other things, expenses from the losses on the sale of assets, minority interest expense, miscellaneous charitable donations, expenditures for certain civic, political and related activities and miscellaneous deductions. Other expense was approximately $0.1 million for the three months ended September 30, 2004 as compared to approximately $2.8 million during the same period in 2003, a decrease of approximately $2.7 million or 96.4 percent. The decrease was primarily due to a decrease of approximately $0.9 million in the liability associated with the deferred compensation plan and retirement restoration plan, a loss of approximately $0.7 million related to the dissolution of a lease in the third quarter of 2003 and a decrease of approximately $0.5 million related to an increase in the allowance for funds used during construction.

Other expense was approximately $3.1 million for the nine months ended September 30, 2004 as compared to approximately $6.3 million during the same period in 2003, a decrease of approximately $3.2 million or 50.8 percent. This difference reflects the recognition, in the first quarter of 2003, of approximately $1.1 million in minority interest expense related to the gain from the sale of approximately 29 miles of transmission lines of the Ozark pipeline that was attributable to the minority interest, a loss of approximately $0.7 million related to the dissolution of a lease in the third quarter of 2003 and a decrease of approximately $0.6 million related to an increase in the allowance for funds used during construction, that was partially offset by an increase of approximately $0.1 million in the liability associated with the deferred compensation plan and retirement restoration plan.

Net interest expense includes interest income, interest expense and other interest charges. Net interest expense was approximately $22.1 million for the three months ended September 30, 2004 as compared to approximately $24.1 million during the same period in 2003, a decrease of approximately $2.0 million or 8.3 percent. This decrease was primarily due to an increase in the allowance for borrowed funds used during construction (approximately $0.8 million), lower interest expense accruals (approximately $0.6 million) during the three months ended September 30, 2004 as compared to the same period in 2003 due to a reduction in long-term debt and lower interest rates, a reduction in interest expense of approximately $0.3 million due to the early retirement of long-term debt and a decrease of approximately $0.2 million in interest expense due to a lower average commercial paper balance for the three months ended September 30, 2004 as compared to the same period in 2003.

Net interest expense was approximately $68.7 million for the nine months ended September 30, 2004 as compared to approximately $73.8 million during the same period in 2003, a decrease of approximately $5.1 million or 6.9 percent. This decrease was primarily due to lower interest expense accruals (approximately $1.7 million) during the nine months ended September 30, 2004 as compared to the same period in 2003 due to a reduction in long-term debt and lower interest rates, a decrease of approximately $1.6 million in interest expense due to a lower average commercial paper balance for the nine months ended September 30, 2004 as compared to the same period in 2003, an increase in the allowance for borrowed funds used during construction (approximately $0.7 million) and a reduction in interest expense of approximately $0.3 million due to the early retirement of long-term debt.

Income tax expense was approximately $51.0 million for the three months ended September 30, 2004 as compared to approximately $59.4 million during the same period in 2003, a decrease of approximately $8.4 million or 14.1 percent. The decrease was primarily due to lower pre-tax income for Enogex and OG&E and a change in the timing of the recognition of book and tax permanent differences in 2004. Amortization of the federal investment tax credits was approximately $1.3 million for each of the three month periods ended September 30, 2004 and 2003.

Income tax expense was approximately $71.5 million for the nine months ended September 30, 2004 as compared to approximately $80.7 million during the same period in 2003, a decrease of approximately $9.2 million or 11.4 percent. The decrease was primarily due to lower pre-tax income for Enogex and OG&E, the recognition of additional Oklahoma state tax credits of approximately $3.2 million during the nine months ended September 30, 2004 and a change in the timing of the recognition of book and tax permanent differences in 2004. Amortization of the federal investment tax credits was approximately $3.9 million for each of the nine month periods ended September 30, 2004 and 2003.

Enogex – Discontinued Operations

Enogex sold its interests in NuStar for approximately $37.0 million in February 2003. The Company recognized approximately a $1.4 million after tax gain related to the sale of these assets in the first quarter of 2003. Following completion of the final accounting for the NuStar sale, the Company recorded an additional charge of approximately $0.2 million after tax in the

third quarter of 2003. The final accounting is subject to approval by all parties to the sale of the joint venture interest. During the first quarter of 2004, the Company recognized approximately $0.4 million after tax from funds received related to an overpayment for natural gas purchases in a prior period.

As a result of this sale transaction, Enogex's interest in NuStar, which was part of the Natural Gas Pipeline segment, has been reported as discontinued operations for the three and nine months ended September 30, 2004 and 2003 in the Condensed Consolidated Financial Statements. Results for the discontinued operations are summarized and discussed below.

	Three Months Ended September 30,		**Nine Months Ended September 30,**	
(In millions)	**2004**	2003	**2004**	2003
Operating revenues	**$ ---**	$ ---	**$ 0.7**	$ 7.8
Gas purchased for resale	---	---	---	5.9
Natural gas purchases - other	---	---	---	0.6
Gross margin on revenues	---	---	**0.7**	1.3
Other operation and maintenance	---	---	---	1.1
Depreciation	---	---	---	0.2

Taxes other than income	---	---	---	0.1
Operating income (loss)	---	---	**0.7**	(0.1)
Other income	---	(0.5)	---	1.9
Net interest expense	---	---	---	0.1
Income tax expense	---	1.3	**0.3**	2.2
Net income (loss)	**$** ---	$ (1.8)	**$ 0.4**	$ (0.5)

Following the sale of NuStar in February 2003, no operations of NuStar are reflected in the Condensed Consolidated Financial Statements except for approximately $0.7 million received during the first quarter of 2004 related to an overpayment of natural gas purchases in a prior period.

Financial Condition

The balance of Cash and Cash Equivalents was approximately $28.1 million and $245.6 million at September 30, 2004 and December 31, 2003, respectively, a decrease of approximately $217.5 million or 88.6 percent. The balance at December 31, 2003 was primarily due to an increase in short-term investments at December 31, 2003 in anticipation of the need for funds to purchase the McClain Plant, which was originally expected to occur by December 31, 2003, and, which was ultimately completed on July 9, 2004.

The balance of Accounts Receivable was approximately $409.2 million and $350.2 million at September 30, 2004 and December 31, 2003, respectively, an increase of approximately $59.0 million or 16.8 percent. The increase was primarily due to higher natural gas prices and volumes associated with Enogex's activities in the third quarter of 2004 in addition to an increase in OG&E's billings to its customers reflecting higher fuel costs and increased usage due to warmer weather during September 2004 as compared to December 2003.

The balance of Accrued Unbilled Revenues was approximately $67.8 million and $38.0 million at September 30, 2004 and December 31, 2003, respectively, an increase of approximately $29.8 million or 78.4 percent. The increase reflects higher seasonal electric rates and increased usage due to warmer weather during September 2004 as compared to December 2003.

The balance of Fuel Inventories was approximately $119.5 million and $163.3 million at September 30, 2004 and December 31, 2003, respectively, a decrease of approximately $43.8 million or 26.8 percent. The decrease was primarily due to inventory sales at Enogex during the nine months ended September 30, 2004.

The balance of current Price Risk Management assets was approximately $141.6 million and $61.3 million at September 30, 2004 and December 31, 2003, respectively, an increase of approximately $80.3 million. The increase was primarily due to an increase in park and loan transactions and natural gas storage injections and withdrawals associated with OGE Energy Resources, Inc.'s ("OERI") activities during the nine months ended September 30, 2004. This increase is offset by an increase in current Price Risk Management liabilities.

The balance of the Gas Imbalance asset was approximately $33.1 million and $70.0 million at September 30, 2004 and December 31, 2003, respectively, a decrease of approximately $36.9 million or 52.7 percent. The Gas Imbalance asset is comprised of planned or managed imbalances related to Enogex's marketing 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 $23.8 million and $45.4 million at September 30, 2004 and December 31, 2003, respectively, a decrease of approximately $21.6 million or 47.6 percent. The decrease was due to the completion of the park and loan transactions during the nine months ended September 30, 2004. The Company expects to obtain and sell approximately half of this gas during the fourth quarter of 2004. Operational imbalances were approximately $9.3 million and $24.6 million at September 30, 2004 and December 31, 2003, respectively, a decrease of approximately $15.3 million or 62.2 percent. The decrease was due to a reduction of volumes partially offset by an increase in natural gas prices.

The balance of Fuel Clause Under Recoveries was approximately $48.9 million at September 30, 2004. The balance of Fuel Clause Over Recoveries (net of Fuel Clause Under Recoveries) was approximately $28.4 million at December 31, 2003. The increase in fuel clause under recoveries was due to under recoveries from OG&E's customers as OG&E's cost of fuel exceeded the amount billed during 2004. The cost of fuel subject to recovery through the fuel clause mechanism was approximately $2.41 per MMBtu in September 2004, and was approximately $1.21 per MMBtu in December 2003. 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 allow OG&E to amortize under or over recovery.

The balance of Prepaid Benefit Obligation was approximately $100.7 million and $55.7 million at September 30, 2004 and December 31, 2003, respectively, an increase of

approximately $45.0 million or 80.8 percent. The increase was primarily due to the Company funding its pension plan during the second and third quarters of 2004 partially offset by pension accruals being credited to the prepaid benefit obligation.

The balance of Short-Term Debt was approximately $10.2 million and $202.5 million at September 30, 2004 and December 31, 2003, respectively, a decrease of approximately $192.3 million or 95.0 percent. The balance at December 31, 2003 was primarily due to the incurrence of short-term debt in anticipation of the expected 2003 year-end closing of the acquisition of the McClain Plant, which was ultimately completed on July 9, 2004. In conjunction with the acquisition of the McClain Plant, the Company issued short-term debt to fund a portion of the acquisition, and, as a result, the short-term debt balance was approximately $216.1 million at July 31, 2004. On August 4, 2004, OG&E issued $140.0 million of long-term debt to replace these short-term borrowings.

The balance of Accounts Payable was approximately $312.3 million and $280.2 million at September 30, 2004 and December 31, 2003, respectively, an increase of approximately $32.1 million or 11.5 percent. The increase was primarily due to higher natural gas prices and volumes associated with Enogex's activities in the third quarter of 2004.

The balance of Accrued Taxes was approximately $74.6 million and $18.7 million at September 30, 2004 and December 31, 2003, respectively, an increase of approximately $55.9 million. The increase was primarily due to the Company's results of operations for the nine months ended September 30, 2004 and the timing of income tax payments in 2004.

The balance of current Price Risk Management liabilities was approximately $162.1 million and $46.9 million at September 30, 2004 and December 31, 2003, respectively, an increase of approximately $115.2 million. The increase was primarily due to an increase in park and loan transactions and natural gas storage injections and withdrawals associated with OERI's activities during the nine months ended September 30, 2004. This increase was partially offset by an increase in current Price Risk Management assets.

The balance of Long-Term Debt was approximately $1.5 billion and $1.4 billion at September 30, 2004 and December 31, 2003, respectively, an increase of approximately $0.1 billion or 7.1 percent. The increase was primarily due to the issuance of $140.0 million of long-term debt in August 2004 by OG&E to replace the short-term borrowings initially issued to finance the McClain Plant acquisition. This increase was partially offset by long-term debt maturities and the early retirement of long-term debt during the nine months ended September 30, 2004.

Off-Balance Sheet Arrangements

Off-balance sheet arrangements include any transactions, agreements or other contractual arrangements to which an unconsolidated entity is a party and under which the Company has: (i) any obligation under a guarantee contract having specific characteristics as defined in Financial Accounting Standards Board ("FASB") Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of

Others"; (ii) a retained or contingent interest in assets transferred to an unconsolidated entity or similar arrangement that serves as credit, liquidity or market risk support to such entity for such assets; (iii) any obligation, including a contingent obligation, under a contract that would be accounted for as a derivative instrument but is indexed to the Company's own stock and is classified in stockholders' equity in the Company's consolidated balance sheet; or (iv) any obligation, including a contingent obligation, arising out of a variable interest as defined in FASB Interpretation No. 46, "Consolidation of Variable Interest Entities an interpretation of Accounting Research Bulletin No. 51," in an unconsolidated entity that is held by, and material to, the Company, where such entity provides financing, liquidity, market risk or credit risk support to, or engages in leasing, hedging or research and development services with, the Company. Except as set forth below, there have been no significant changes in the Company's off-balance sheet arrangements reported in the Company's Form 10-K for the year ended December 31, 2003.

Heat Pump Loans

OG&E had a heat pump loan program whereby, qualifying customers could obtain a loan from OG&E to purchase a heat pump. In November 1999, OG&E sold approximately $12.7 million of its heat pump loans in a securitization transaction through OGE Consumer Loan II LLC. In October 2004, OG&E repurchased the outstanding heat pump loan balance of approximately $1.1 million. OG&E expects to record a loss of less than $0.1 million in the fourth quarter of 2004 related to this transaction.

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 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 and permanent financings.

Early Retirement of Long-Term Debt

In 1998, Enogex issued a note of approximately $5.7 million payable to an unaffiliated former partial interest owner of NOARK. The note had a maturity date of July 1, 2020 and an interest rate of 7.00 percent. Principal and interest payments of approximately $0.8 million were due annually beginning July 1, 2004. In July 2004, Enogex made the initial $0.8 million payment and also made a payment of approximately $7.8 million, which included accrued interest since inception of the note, to repay the outstanding note balance and satisfy its remaining obligations related to this note. Enogex recorded a pre-tax gain of approximately $0.1 million in the third quarter of 2004 related to this transaction.

Interest Rate Swap Agreements

Fair Value Hedges

At September 30, 2004 and December 31, 2003, the Company had three outstanding interest rate swap agreements that qualified as fair value hedges: (i) OG&E entered into an interest rate swap agreement, effective March 30, 2001, to convert $110.0 million of 7.30 percent fixed rate debt due October 15, 2025, to a variable rate based on the three month London InterBank Offering Rate ("LIBOR") and (ii) Enogex entered into two separate interest rate swap agreements, effective July 15, 2002 and October 24, 2002, to convert a total of $200.0 million ($100.0 million for each interest rate swap agreement) of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the six month LIBOR in arrears. The objective of these interest rate swaps was to achieve a lower cost of debt and to raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standards. These interest rate swaps qualified as fair value hedges under Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, and met all of the requirements for a determination that there was no ineffective portion as allowed by the shortcut method under SFAS No. 133.

At September 30, 2004 and December 31, 2003, the fair values pursuant to the interest rate swaps were approximately $9.3 million and $7.6 million, respectively, and the hedges were classified as Deferred Charges and Other Assets – Price Risk Management in the Condensed Consolidated Balance Sheets. A corresponding net increase of approximately $9.3 million and $7.6 million was reflected in Long-Term Debt at September 30, 2004 and December 31, 2003, respectively, as these fair value hedges were effective at September 30, 2004 and December 31, 2003.

Cash Flow Hedges

At September 30, 2004, the Company had four outstanding interest rate swap agreements that qualified as cash flow hedges. The Company entered into four separate interest rate swap agreements, effective April 16, 2004, April 21, 2004, May 17, 2004 and July 16, 2004, respectively, to hedge approximately $20.0 million, $30.0 million, $20.0 million and $10.0 million, respectively, of future interest payments of long-term debt expected to be issued later this year related to the redemption of $200.0 million of 8.375 percent trust preferred securities of OGE Energy Capital Trust I, a wholly-owned financing trust of the Company. These interest rate swap agreements originally matured on October 15, 2004 but the maturity date was extended to November 8, 2004. The objective of these interest rate swaps is to protect against the volatility of interest rates affecting future interest payments. These interest rate swaps qualified as cash flow hedges under SFAS No. 133 and met all of the requirements for a determination that there was no ineffective portion as allowed by the hypothetical derivative method under SFAS No. 133.

At September 30, 2004, the fair values for these interest rate swaps was approximately $4.2 million and the hedges were classified as Current Liabilities – Price Risk Management in the Condensed Consolidated Balance Sheets. A corresponding net decrease of approximately

$4.2 million was reflected in Accumulated Other Comprehensive Income at September 30, 2004 as these cash flow hedges were effective at September 30, 2004.

Trust Originated Preferred Securities

On October 21, 1999, OGE Energy Capital Trust I issued $200.0 million principal amount of 8.375 percent trust preferred securities that mature on October 15, 2039. On October 15, 2004, the Company redeemed all of the outstanding trust preferred securities at $25 per share and issued approximately $170.0 million in commercial paper. The Company expects to refinance a portion of this short-term debt with long-term debt during the fourth quarter of 2004. At September 30, 2004, the trust preferred securities were classified as long-term debt in the Condensed Consolidated Balance Sheets. In October 2004, the Company expects to write off approximately $5.9 million related to unamortized debt issuance costs for the trust preferred securities.

Future Capital Requirements

Capital Expenditures

The Company's current 2004 to 2006 construction program includes the purchase of New Generation as discussed below. OG&E has approximately 430 MWs of contracts with qualified cogeneration facilities and small power production producers' ("QF contracts") that will expire at the end of 2007, unless extended by OG&E. In addition, effective September 1, 2004, OG&E entered into a new 15-year power sales agreement with PowerSmith Cogeneration Project, L.P. ("PowerSmith"). OG&E will continue reviewing all of the supply alternatives to these expiring QF contracts that minimize the total cost of generation to its customers, including exercising its options (if applicable) to extend these QF contracts at pre-determined rates. Accordingly, OG&E will continue to explore opportunities to build or buy power plants in order to serve its native load. As a result of the high volatility of current natural gas prices and the increase in natural gas prices, OG&E will also assess the feasibility of constructing additional base load coal-fired units. See Note 17 of Notes to Condensed Consolidated Financial Statements for a description of the new PowerSmith QF contract.

OG&E completed the acquisition of NRG McClain LLC's 77 percent interest in the McClain Plant on July 9, 2004. The purchase price for the interest in the McClain Plant was approximately $160.0 million. See "Overview – Regulatory Matters and Plant Acquisition." OG&E temporarily funded the acquisition with short-term borrowings from the Company. On August 4, 2004, OG&E issued $140.0 million of long-term debt to replace these short-term borrowings. Also, on August 9, 2004, the Company made a capital contribution to OG&E of approximately $153.0 million. To reliably meet the increased electricity needs of OG&E's customers during the foreseeable future, OG&E will continue to invest to maintain the integrity of the delivery system. Approximately $10.5 million of the Company's capital expenditures budgeted for 2004 are to comply with environmental laws and regulations.

Pension and Postretirement Benefit Plans

The Company previously disclosed in its Form 10-K for the year ended December 31, 2003 that it expected to contribute approximately $56.0 million to its pension plan in 2004. After the benefit liability was remeasured as of January 1, 2004, the Company decided to make an additional contribution of $13.0 million (for a total anticipated contribution of $69.0 million in 2004) to ensure the pension plan maintains an adequate funded status. The Company funded this $69.0 million contribution to its pension plan during the second and third quarters of 2004. 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.

Future Sources of Financing

Management expects that internally generated funds, funds received from the 2003 equity offering, proceeds from the sales of common stock pursuant to the Company's DRIP and long and short-term debt will be adequate over the next three years to meet anticipated capital expenditures, operating needs, payment of dividends and maturities of long-term debt. As discussed below, the Company utilizes short-term debt to satisfy temporary working capital needs and as an interim source of financing capital expenditures until permanent financing is arranged. The Company issued equity in the third quarter of 2003 and issued common stock pursuant to the DRIP during 2003. With the acquisition of the McClain Plant complete, OG&E issued long-term debt to permanently finance the McClain Plant acquisition in August 2004 and the Company issued common stock pursuant to the DRIP during the third quarter of 2004.

Short-Term Debt

Short-term borrowings generally are used to meet working capital requirements. The short-term debt balance was approximately $10.2 million and $202.5 million at September 30, 2004 and December 31, 2003, respectively. The balance at December 31, 2003 was primarily due to the incurrence of short-term debt in anticipation of the expected 2003 year-end closing of the acquisition of the McClain Plant, which was ultimately completed on July 9, 2004. In conjunction with the acquisition of the McClain Plant, the Company issued short-term debt to fund a portion of the acquisition, and, as a result, the short-term debt balance was approximately $216.1 million at July 31, 2004. On August 4, 2004, OG&E issued $140.0 million of long-term debt to replace these short-term borrowings.

The following table shows the Company's lines of credit in place and available cash at September 30, 2004. Short-term borrowings could include a combination of bank borrowings and commercial paper.

Lines of Credit and Available Cash *(In millions)*

Entity	Amount Available	Amount Outstanding	Maturity
OGE Energy Corp.	$ 15.0	$ ---	April 6, 2005
OG&E (A)	100.0	---	December 9, 2004
OGE Energy Corp. (A)	300.0	---	December 9, 2004
	415.0	---	
Cash	28.1	N/A	N/A
Total	$ 443.1	$ ---	

(A) These lines of credit are used to back up the Company's commercial paper borrowings, which were approximately $10.2 million at September 30, 2004.

On October 20, 2004, the Company and OG&E entered into revolving credit agreements totaling $550 million. These agreements, which include two separate credit facilities, one for the Company in an amount up to $450 million and one for OG&E in an amount up to $100 million, replaced the Company's and OG&E's current credit facilities in the table above that were to expire on December 9, 2004. Each of the new credit facilities has a five-year term with two options to extend the term for one year. For the OG&E credit facility, OG&E filed an application to issue securities with the OCC in September 2004 and received approval of this transaction in October 2004. Planned uses of the revolving credit include working capital needs, back-up for the Company's commercial paper program, the issuance of letters of credit and for general corporate purposes.

The Company's and OG&E's ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade. Their respective back-up lines of credit contain rating grids that require annual fees and borrowing rates to increase if they suffer an adverse ratings impact. The impact of additional downgrades would result in an increase in the cost of short-term borrowings of approximately five to 20 basis points, 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. In October 2004, OG&E filed an application with the FERC to request a two-year renewal of its current regulatory approval to incur up to $400 million in short-term borrowings at any one time. OG&E's current short-term borrowing authorization expires December 31, 2004.

Asset Sales

Also contributing to the liquidity of the Company have been numerous asset sales by Enogex. Since January 1, 2002, completed sales generated net proceeds of approximately $106.3 million. Sales proceeds generated to date have been used to reduce debt at Enogex and commercial paper at the holding company.

The Company continues to evaluate opportunities to enhance shareowner returns and achieve long-term financial objectives through acquisitions of assets that may complement its existing portfolio and divestitures of idle or under performing assets. Permanent financing may be required for any such acquisitions.

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 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, the allowance for uncollectible accounts receivable, the valuation of energy purchase and sale contracts and natural gas storage inventory and fair value and cash flow hedging policies. 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, 2003.

Accounting Pronouncements

See Note 2 of Notes to Condensed Consolidated Financial Statements for a discussion of recent accounting pronouncements.

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 it appears unlikely in the near future that changes will occur to retail regulation in the states served by OG&E due to the significant problems faced by California in its electric deregulation efforts and other factors, significant changes are possible, which could significantly change the manner in which OG&E conducts its business. These developments at the federal and state levels are described in more detail in Note 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, 2003. The Company currently has two important matters pending before the OCC. See Note 17 of Notes of Condensed Consolidated Financial Statements for a further discussion.

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 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 set forth in Notes 16 and 17 of Notes to Condensed Consolidated Financial Statements in this Form 10-Q, in Note 17 to the Company's Consolidated Financial Statements included in the Company's Form 10-K for the year ended December 31, 2003 and in Note 15 to the Company's Condensed Consolidated Financial Statements included in the Company's Form 10-Q for the quarters ended March 31, 2004 and June 30, 2004, management, after consultation with legal counsel, does not anticipate that liabilities arising out of currently 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. This assessment of currently pending or threatened lawsuits is subject to change.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

Risk Management

The risk management process established by the Company is designed to measure both quantitative and qualitative risks in its businesses. A corporate risk management department, under the direction of a corporate risk oversight committee, has been established to review these risks on a regular basis. The Company is exposed to market risk in its normal course of business, including changes in certain commodity prices and interest rates. The Company also engages in price risk management activities for both trading and non-trading purposes.

To manage the volatility relating to these exposures, the Company enters into various derivative and other forward transactions pursuant to the Company's policies on hedging practices. These positions are monitored using techniques such as mark-to-market valuation, value-at-risk and sensitivity analysis.

Interest Rate Risk

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

The Company's exposure to interest rate risk for changes in interest rates has not significantly changed since December 31, 2003. See Notes 12 and 13 of Notes to Condensed Consolidated Financial Statements in this Form 10-Q for a discussion of the Company's long-term and short-term debt activity.

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 are broken into trading, which includes transactions that are voluntarily entered into to capture subsequent changes in commodity prices, and non-trading, which result from the exposure some of the Company's assets have to commodity prices.

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, subject to a $1.5 million limit, as well as other quantitative risk measurement techniques. These limits are designed to mitigate the possibility of trading activities having a material adverse effect on the Company's operating income.

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 operating income received by the Company as compensation for operating some of its assets. To partially reduce non-trading commodity price risk incurred in the Company's normal course of business caused by these market fluctuations, the Company hedges, through the utilization of derivatives and other forward transactions, the effects these market fluctuations have on the operating income received by the Company as compensation for operating these assets. 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.

Sensitivity analyses have been prepared to estimate the trading and non-trading commodity price exposure to the market risk of the Company's natural gas and natural gas liquids commodity positions. 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. 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. Because quoted market prices are not available for all of the Company's non-trading positions, 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 results of these analyses, which may differ from actual results, are as follows as of September 30, 2004.

(In millions)	Trading	Non-Trading
Commodity price risk, net	$ 1.7	$ 7.8

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. 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 Chief Executive Officer ("CEO") and Chief Financial Officer ("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 recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

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, 2003 and Part II, Item 1 of the Company's Form 10-Q for the quarters ended March 31, 2004 and June 30, 2004, 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.

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

As reported in Note 17 to the Company's Consolidated Financial Statements in the Company's Form 10-K for the year ended December 31, 2003, Enogex, Central Oklahoma Oil and Gas Corp. ("COOG"), Natural Gas Storage Corporation ("NGSC") and certain individual shareholders of COOG and NGSC, have been involved in legal proceedings relating to a gas storage agreement and associated agreements. The parties participated in the Oklahoma County arbitration in May 2004 and the arbitration panel rendered a decision in the Company's favor for approximately $5.0 million on July 15, 2004. On September 13, 2004 the District Court of Oklahoma County confirmed the arbitration award and the judgment was entered. In the Texas case, on August 20, 2004, a hearing was held and the judge confirmed the decision as to Enogex. Also in the Texas case, on October 4, 2004, the plaintiffs filed a first amended petition seeking: (i) declaratory judgment based on collusion to impair collateral; (ii) gross negligence; and (iii) declaratory judgment and confirmation of certain aspects of the award. The plaintiffs have added a request for punitive damages. The jury trial in the United States District Court, Western District of Oklahoma fraudulent transfer cases against certain of the individual shareholders of COOG and NGSC was held from October 12-26, 2004. The case was submitted to the jury on October 25, 2004 and the jury ruled in favor of the Company and Enogex for approximately $6.6 million.

National Steel Corporation

As previously reported in the Company's Form 10-Q for the quarter ended March 31, 2004, National Steel Corporation ("National Steel") voluntarily filed for Chapter 11 bankruptcy protection from creditors in 2002. OERI filed its proof of claim for approximately $0.9 million. In March 2004, National Steel filed an adversary proceeding in the pending bankruptcy against OERI seeking the refund and return of payments made by National Steel to OERI during the 90 days preceding its bankruptcy filing totaling approximately $2.7 million. A settlement of the pending bankruptcy issues was reached in October 2004 between the parties wherein OERI agreed to not pursue its claim in the bankruptcy (approximately a $12,000 claim based on the filed bankruptcy plan) in exchange for National Steel dismissing the pending preference claim.

Item 2. Changes in Securities, Use of Proceeds and Issuer Purchases of Equity Securities.

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

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan
1/1/04 - 1/31/04	105,900	$24.06	N/A	N/A
2/1/04 - 2/29/04	16,400	$24.56	N/A	N/A
3/1/04 - 3/31/04	16,900	$26.01	N/A	N/A
4/1/04 - 4/30/04	138,900	$24.55	N/A	N/A
5/1/04 - 5/31/04	16,600	$24.24	N/A	N/A
6/1/04 - 6/30/04*	51,144	$24.39	N/A	N/A
7/1/04 - 7/31/04	108,500	$24.48	N/A	N/A
8/1/04 - 8/31/04	16,300	$25.21	N/A	N/A
9/1/04 - 9/30/04	26,700	$25.57	N/A	N/A

* This month reflects the following transactions: (i) the surrender to the Company of 7,244 shares of common stock at an average price of $25.14 per share to satisfy tax withholding obligations in connection with the vesting of restricted stock issued to employees; and (ii) the purchase of 43,900 shares of common stock at an average price of $24.27 per share relating to the Company's Stock Ownership and Retirement Savings Plan.

Item 6. Exhibits.

Exhibit No.	Description
31.01	Certifications Pursuant to Rule 13a-15(e)/15d-15(e) 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/ Donald R. Rowlett

Donald R. Rowlett
Vice President and Controller

(On behalf of the registrant and in his capacity as Chief Accounting Officer)

November 4, 2004

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)) 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) 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

c) 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 4, 2004

/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)) 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) 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

c) 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 4, 2004

/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, 2004, 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 4, 2004

/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