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, 2002

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___

As of October 31, 2002, 78,442,426 shares of common stock, par value $0.01 per share, were outstanding.

OGE ENERGY CORP.

FORM 10-Q

FOR THE QUARTER ENDED SEPTEMBER 30, 2002

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

OGE ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	September 30, 2002	December 31, 2001
	(In millions)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 7.1	$ 32.5
Accounts receivable - customers, less reserve of $13.8 and $8.9, respectively	289.4	198.3
Accrued unbilled revenues	53.3	35.6
Accounts receivable - other	19.3	17.0
Fuel inventories	100.1	77.2
Materials and supplies, at average cost	41.5	38.5
Price risk management	20.3	21.2
Accumulated deferred tax assets	14.5	10.0
Prepayments	2.5	7.8
Fuel clause under recoveries	17.1	---
Provision for payments of take or pay gas	0.4	30.8
Current assets of discontinued operations	8.0	8.0
Other	1.5	1.7
Total current assets	575.0	478.6
OTHER PROPERTY AND INVESTMENTS, at cost	76.4	40.3
PROPERTY, PLANT AND EQUIPMENT		
In service	5,515.8	5,372.0
Construction work in progress	41.7	47.8
Total property, plant and equipment	5,557.5	5,419.8
Less accumulated depreciation	2,320.2	2,243.0
Net property, plant and equipment	3,237.3	3,176.8
In service of discontinued operations	110.2	135.2
Less accumulated depreciation	40.4	48.3
Net property, plant and equipment of discontinued operations	69.8	86.9
Net property, plant and equipment	3,307.1	3,263.7
DEFERRED CHARGES AND OTHER ASSETS		
Provision for payments of take or pay gas	32.5	8.5
Income taxes recoverable through future rates, net	36.8	37.6
Intangible asset - unamortized prior service cost	47.3	47.3
Prepaid benefit obligation	51.0	21.3
Price risk management	13.1	13.4
Deferred charges and other assets of discontinued operations	0.8	0.7
Other	113.2	85.2
Total deferred charges and other assets	294.7	214.0
TOTAL ASSETS	$ 4,253.2	$ 3,996.6

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

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

	September 30, 2002	December 31, 2001

LIABILITIES AND STOCKHOLDERS' EQUITY	(In millions)	
CURRENT LIABILITIES		
Short-term debt	$ 289.6	$ 115.0
Accounts payable	195.1	145.8
Dividends payable	26.0	25.9
Customers' deposits	31.0	28.4
Accrued taxes	105.8	28.4
Accrued interest	29.1	40.3
Tax collections payable	9.3	4.7
Accrued vacation	17.5	16.9
Long-term debt due within one year	10.0	115.0
Provision for payments of take or pay gas	0.4	30.8
Fuel clause over recoveries	---	23.4
Price risk management	12.8	7.9
Capital lease obligation	0.7	0.4
Labor accrued but not paid	3.9	0.7
Current liabilities of discontinued operations	4.4	3.1
Other	15.6	13.0
Total current liabilities	751.2	599.7
LONG-TERM DEBT	1,533.7	1,526.3
DEFERRED CREDITS AND OTHER LIABILITIES		
Capital lease obligation - non-current	8.6	8.9
Accrued pension and benefit obligations	102.4	100.1
Accumulated deferred income taxes	659.0	634.9
Accumulated deferred investment tax credits	48.4	52.3
Price risk management	0.4	3.8
Provision for payments of take or pay gas	32.5	8.5
Deferred credits and other liabilities of discontinued operations	9.4	10.5
Other	19.3	11.0
Total deferred credits and other liabilities	880.0	830.0
STOCKHOLDERS' EQUITY		
Common stockholders' equity	449.0	444.7
Retained earnings	661.2	617.9
Accumulated other comprehensive loss, net of tax	(21.9)	(22.0)
Total stockholders' equity	1,088.3	1,040.6
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 4,253.2	$ 3,996.6

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

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	**2001 ***	**2002**	**2001**
	(In millions, except per share data)			
OPERATING REVENUES	$ 612.7	$ 656.0	$ 1,488.4	$ 1,710.4
COST OF GOODS SOLD	276.9	322.0	767.4	1,009.0
Gross margin on revenues	335.8	334.0	721.0	701.4
Other operation and maintenance	88.9	87.9	270.8	272.2
Depreciation and amortization	45.5	42.7	136.7	129.6
Taxes other than income	15.6	16.0	48.7	48.7
OPERATING INCOME	185.8	187.4	264.8	250.9
OTHER INCOME	1.0	0.6	3.7	4.7
OTHER EXPENSE	(1.7)	(0.8)	(3.7)	(5.1)
EARNINGS BEFORE INTEREST AND TAXES	185.1	187.2	264.8	250.5
INTEREST INCOME (EXPENSE)				
Interest income	0.5	0.7	1.5	2.9
Interest on long-term debt	(21.6)	(24.0)	(65.2)	(75.4)

Interest on trust preferred securities...	(4.3)	(4.3)	(13.0)	(13.0)
Allowance for borrowed funds used during construction....................	0.1	0.2	0.8	0.6
Other interest charges..................	(2.2)	(3.8)	(6.4)	(11.0)
Net interest expense..................	(27.5)	(31.2)	(82.3)	(95.9)
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES....................................	157.6	156.0	182.5	154.6
INCOME TAX EXPENSE.........................	60.9	59.5	68.0	57.5
INCOME FROM CONTINUING OPERATIONS..........	96.7	96.5	114.5	97.1
DISCONTINUED OPERATIONS (NOTE 5)				
Income from discontinued operations......	0.1	0.1	3.6	12.5
Income tax expense (benefit)............	(2.2)	(0.5)	(3.1)	2.7
Income from discontinued operations......	2.3	0.6	6.7	9.8
NET INCOME................................	$ 99.0	$ 97.1	$ 121.2	$ 106.9
BASIC AVERAGE COMMON SHARES OUTSTANDING....	78.1	77.9	78.0	77.9
DILUTED AVERAGE COMMON SHARES OUTSTANDING..	78.1	77.9	78.1	77.9
BASIC EARNINGS PER AVERAGE COMMON SHARE				
Income from continuing operations........	$ 1.24	$ 1.24	$ 1.47	$ 1.25
Income from discontinued operations, net of tax.............................	0.03	0.01	0.08	0.12
NET INCOME..............................	$ 1.27	$ 1.25	$ 1.55	$ 1.37
DILUTED EARNINGS PER AVERAGE COMMON SHARE				
Income from continuing operations........	$ 1.24	$ 1.24	$ 1.47	$ 1.25
Income from discontinued operations, net of tax.............................	0.03	0.01	0.08	0.12
NET INCOME..............................	$ 1.27	$ 1.25	$ 1.55	$ 1.37
DIVIDENDS PAID PER SHARE..................	$ 0.3325	$ 0.3325	$ 0.9975	$ 0.9975

*These amounts have been restated as described in Notes 2 and 5 to Condensed Consolidated Financial Statements.

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, 2002	Nine Months Ended September 30, 2001
	(In millions)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income..	$ 121.2	$ 106.9
Adjustments to reconcile net income to net cash provided from operating activities		
Income from discontinued operations.........................	(6.7)	(9.8)
Depreciation and amortization...............................	136.7	129.6
Deferred income taxes and investment tax credits, net........	1.3	20.8
Gain on sale of assets......................................	(2.1)	(0.2)
Price risk management.......................................	15.3	(32.3)
Accumulated other comprehensive income (loss)................	0.1	(1.1)
Other assets..	(185.6)	41.6
Other liabilities...	109.3	(56.2)
Change in certain current assets and liabilities		
Accounts receivable - customers..........................	(91.1)	168.9
Accrued unbilled revenues................................	(17.7)	(2.3)
Fuel, materials and supplies inventories..................	(25.8)	124.0
Accumulated deferred tax assets..........................	(4.5)	0.2
Other current assets.....................................	16.3	38.0
Accounts payable...	54.5	(195.7)
Accrued taxes..	74.2	47.5
Accrued interest...	(11.3)	(10.2)
Other current liabilities................................	(44.4)	11.7
Net Cash Provided from Operating Activities.............	139.7	381.4

CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(188.8)	(171.6)
Proceeds from sale of assets	10.8	0.8
Other investing activities	(0.5)	0.2
Net Cash Used in Investing Activities	(178.5)	(170.6)
CASH FLOWS FROM FINANCING ACTIVITIES		
Retirement of long-term debt	(114.0)	(10.4)
Increase (decrease) in short-term debt, net	177.2	(159.0)
Premium on issuance (retirement) of common stock	4.3	(0.1)
Distribution from minority interest	---	1.4
Capital lease obligation	---	(0.3)
Cash dividends declared on common stock	(77.9)	(77.7)
Net Cash Used in Financing Activities	(10.4)	(246.1)
DISCONTINUED OPERATIONS		
Net cash provided from operating activities	14.2	45.4
Net cash provided from (used in) investing activities	11.0	(10.0)
Net cash used in financing activities	(1.4)	---
Net Cash Provided from Discontinued Operations	23.8	35.4
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	(25.4)	0.1
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	32.5	0.5
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 7.1	$ 0.6
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION		
CASH PAID DURING THE PERIOD FOR		
Interest (net of amount capitalized $0.8 and $0.6, respectively)	$ 96.9	$ 95.6
Income taxes	$ 11.8	$ 6.0
NON-CASH INVESTING AND FINANCING ACTIVITIES		
Interest rate swap	$ (13.0)	$ (12.8)
Change in fair value of long-term debt	$ 13.0	$ 12.8
Assumption of asset and related debt	$ 33.8	$ ---

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 segment, which operations are conducted through Oklahoma Gas and Electric Company ("OG&E") and the Energy Supply segment, which operations are conducted through Enogex Inc. and its subsidiaries ("Enogex"). All significant intercompany transactions have been eliminated in consolidation.

OG&E generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. OG&E sold its retail gas business in 1928 and is no longer engaged in the gas distribution business. OG&E's operations are subject to the jurisdiction of the Oklahoma Corporation Commission ("OCC"), the Arkansas Public Service Commission ("APSC") and the Federal Energy Regulatory Commission ("FERC"). OG&E owns and operates eight generating stations and is the largest electric utility in Oklahoma. OG&E's franchised service territory includes the Fort Smith, Arkansas area, which is the second largest market in that state.

Enogex produces, gathers, processes, transports, markets and stores natural gas and produces, transports and markets natural gas liquids primarily in Oklahoma, Arkansas and west Texas. As discussed in Note 5, Enogex has sold or is in the process of selling significant portions of its exploration and production assets and is in the process of selling the majority of its assets in west Texas. Enogex is also involved in commodity sales and services related to natural gas and electric power and provides energy-related services for corporate commodity price risk management and energy forward price evaluations primarily through its wholly-owned subsidiary, OGE Energy Resources Inc. Enogex owns and operates the tenth largest natural gas pipeline system in the United States in terms of miles of pipe in service. Enogex has a significant investment in natural gas gathering, processing, transmission and storage in the major gas producing basins of Oklahoma.

Basis of Consolidation

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, 2002 and December 31, 2001, the results of operations for the three and nine months ended September 30, 2002 and 2001, and the results of cash flows for the nine months ended September 30, 2002 and 2001, have been included and are of a normal recurring nature. Certain amounts have been reclassified in the condensed consolidated financial statements to conform to the 2002 presentation.

Operating results for the three and nine months ended September 30, 2002 are not necessarily indicative of the results that may be expected for the year ending December 31, 2002 or for any future period. In preparing these 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. Actual results could differ from those estimates. The accompanying 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, 2001.

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 expected recovery from customers in future rates. Likewise, certain credits that would otherwise reduce expense are deferred as regulatory liabilities based on expected flowback to customers in future rates. Management’s expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment. OG&E has deferred approximately $5.4 million of operating costs incurred to restore power to customers subsequent to the January 30, 2002 ice storm. OG&E is seeking approval from the OCC to recover these deferred costs over a three-year period. See Notes 8 and 11 and “Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations–Regulation and Rates–Recent Regulatory Matters” for a further discussion. At September 30, 2002, regulatory assets of $89.8 million and regulatory liabilities of $28.8 million are being amortized and reflected in rates charged to customers over periods of up to 20 years.

Fuel Inventories

Fuel inventories for the generation of electricity consists of coal, natural gas and oil. These inventories are accounted for under the last-in, first-out cost method. Natural gas products

inventories used in Enogex's energy trading activities are valued at market. See Note 2 for a further discussion.

Income Taxes

The Company files consolidated income tax returns. Income taxes are allocated to each company based on its separate taxable income or loss.

Investment tax credits on electric utility property have been deferred and are being amortized to income over the life of the related property.

The Company uses a straight-line method to amortize investment tax credit. This can produce an artificially low effective tax rate when net income before taxes is relatively low, which usually occurs in the first quarter of each year. On an annual basis, the impact of the investment tax credit from year to year is relatively stable. Additionally, the Company reversed previously accrued federal income tax at a subsidiary of Enogex. The reversal of income tax expense was related to a disagreement between Enogex and the Internal Revenue Service, which was resolved in favor of Enogex. Also, the Company received a refund of Oklahoma state income tax related to Oklahoma investment tax credits.

Cash and Cash Equivalents

For purposes of these condensed consolidated financial statements, the Company considers all highly liquid debt instruments purchased with a maturity of three months or less to be cash equivalents. These investments are carried at cost, which approximates market value.

2. Accounting Pronouncements

Effective January 1, 2001, the Company adopted SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended by SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities - Deferral of the Effective Date of FASB 133" and SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities." SFAS No. 133 requires the Company to record all derivatives on the Balance Sheet at fair value. Changes in the fair value of derivatives that are not designated as hedges, as well as the ineffective portion of hedge derivatives, must be recognized as a derivative fair value gain or loss in the accompanying Condensed Consolidated Statements of Income. Changes in the fair value of effective fair value hedges are recorded in Price Risk Management in the accompanying Condensed Consolidated Balance Sheets, with a corresponding net change in the hedged asset or liability. Changes in the fair value of effective cash flow hedges are recorded as a component of Accumulated Other Comprehensive Income, which is later reclassified to earnings when the related hedged transaction is reflected in income. Physical delivery contracts, which are deemed to be normal purchases or normal sales, are not accounted for as derivatives.

The Company accounted for the adoption of SFAS No. 133 by recording a cumulative effect transition adjustment debit to Accumulated Other Comprehensive Income of

approximately $26.9 million ($16.5 million net of tax). This unrealized loss was related to the derivative fair value of qualifying cash flow hedges as of the date of adoption and was later reclassified to earnings when the related hedged transactions were reflected in income. As of December 31, 2001, this amount had been reclassified to earnings. However, the initial unrealized loss was offset by a subsequent gain on these qualifying cash flow hedges of approximately $21.4 million ($13.1 million net of tax). As of December 31, 2001, the Company also recorded a gain, included in Operating Revenues, related to the ineffective portion of hedge derivatives, for production hedges, of $4.7 million ($3.0 million net of tax) resulting in an overall loss of approximately $0.8 million ($0.4 million net of tax).

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 will affect the Company's accrued plant removal costs for generation, transmission, distribution, processing and oil and gas production facilities and will require 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. The associated asset retirement costs are capitalized as part of the carrying amount of the long-lived asset. Adoption of SFAS No. 143 is required for financial statements issued for fiscal years beginning after June 15, 2002. The Company will adopt this new standard effective January 1, 2003. Management has not yet determined the impact of this new standard on its consolidated financial position or results of operations.

In August 2001, the FASB issued SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets." SFAS No. 144 requires that an impairment loss be recognized only if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows and that the measurement of any impairment loss be the difference between the carrying amount and the fair value of the long-lived asset. SFAS No. 144 also requires companies to separately report discontinued operations and extends that reporting to a component of an entity that either has been disposed of (by sale, abandonment, or in a distribution to owners) or is classified as held for sale. Assets to be disposed of are reported at the lower of the carrying amount or fair value less costs to sell. Adoption of SFAS No. 144 is required for financial statements issued for fiscal years beginning after December 15, 2001. The Company adopted SFAS No. 144 effective January 1, 2002 and the adoption of this new standard did not have a material impact on its consolidated financial position or results of operations.

In June 2002, the Emerging Issues Task Force ("EITF") reached a consensus on certain issues covered in EITF Issue No. 02-3, "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities." EITF 02-3 requires that all mark-to-market gains and losses on financial and physical energy trading contracts (whether realized or unrealized) be shown net in the Income Statement for financial statements issued for periods ending after July 15, 2002, with reclassification required for prior periods presented. The Company adopted this consensus effective July 1, 2002. EITF 02-3 impacted the amount of operating revenues and cost of goods sold presented, however, it did not affect the gross margin on revenues. As a result of adhering to EITF 02-3, operating revenues were reduced by

approximately $151.6 million and $848.9 million for the three and nine months ended September 30, 2001, respectively. See "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations - Results of Operations - Enogex" for total volumes traded related to energy trading contracts.

In October 2002, the EITF reached a consensus to rescind EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities", as amended. Effective October 25, 2002, all new contracts that would have been accounted for under EITF 98-10 should no longer be marked to market through earnings. Adoption of the consensus rescinding EITF 98-10 is required to be accounted for as a cumulative effect of a change in accounting principle in accordance with Accounting Principles Board Opinion No. 20, "Accounting Changes", effective for the first fiscal quarter beginning after December 15, 2002. The Company will adopt this consensus effective January 1, 2003. Management has not yet determined the impact of this new standard on its consolidated financial position or results of operations.

In July 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." SFAS No. 146 addresses financial accounting and reporting for costs associated with exit and disposal activities and supersedes EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs

Incurred in a Restructuring).” SFAS No. 146 requires recognition of a liability for a cost associated with an exit or disposal activity when the liability is incurred, as opposed to when the entity commits to an exit plan under EITF 94-3. SFAS No. 146 also establishes that the liability should initially be measured and recorded at fair value. Adoption of SFAS No. 146 is required for exit and disposal activities initiated after December 31, 2002. The Company will adopt this new standard effective January 1, 2003. Management has not yet determined the impact of this new standard on its consolidated financial position or results of operations.

3. Price Risk Management Activities

Enogex, in the normal course of business, enters into fixed price contracts for either the purchase or sale of natural gas and electricity at future dates. Due to fluctuations in the natural gas, natural gas liquids and electricity markets, Enogex may buy or sell natural gas, natural gas liquids and electricity futures contracts, swaps or options to hedge the price and basis risk associated with the specifically identified purchase or sales contracts as well as other long and short commodity positions associated with the operation and management of its assets. The Company accounts for changes in the market value of qualifying hedging instruments in accordance with SFAS No. 133. The specific accounting treatment for changes in the market value of the derivative instrument is determined based on the designation of the derivative instrument as a cash flow or fair value hedge and the effectiveness of the derivative instrument. Additionally, Enogex may use derivative contracts as an enhancement or speculative trade, subject to the Company’s risk management policies. Enogex recognizes the gain or loss on enhancement or speculative contracts as the market values change in the results of operations. The Company adheres to EITF 98-10 under which all of Enogex’s energy trading contracts are

marked to market with the corresponding market gains or losses recognized in the results of operations. In October 2002, the EITF reached a consensus to rescind EITF 98-10. See Note 2 for a further discussion.

4. Comprehensive Income

The components of total comprehensive income for the three and nine months ended September 30, 2002 and 2001, respectively, are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	**2002**	2001	**2002**	2001
Net income	**$ 99.0**	$ 97.1	**$121.2**	$106.9
Other comprehensive income (loss), net of tax:				
Transition adjustment	**---**	---	**---**	(16.5)
Change in derivative fair value	**---**	(0.6)	**---**	16.0
Reclassification adjustments - contract settlements	**---**	1.5	**0.1**	(0.6)
Total other comprehensive income (loss), net of tax	**---**	0.9	**0.1**	(1.1)
Total comprehensive income	**$ 99.0**	$ 98.0	**$121.3**	$105.8

Accumulated other comprehensive loss at both September 30, 2002 and December 31, 2001 included a $21.9 million after-tax loss ($35.8 million pre-tax) related to a minimum pension liability adjustment. Also included at December 31, 2001 was $0.1 million related to hedging activity.

5. Discontinued Operations

On August 5, 2002, Enogex entered into an Agreement of Sale and Purchase with Chesapeake Exploration Limited Partnership to sell all of its exploration and production assets located in Oklahoma, Texas, Arkansas and Mississippi for approximately $15.0 million. The effective date of the sale was July 1, 2002 and the closing occurred on September 19, 2002. The Company recognized a $2.3 million loss related to the sale of these assets. These assets were part of the Energy Supply segment.

Enogex is currently negotiating the sale of its exploration and production assets located in Michigan and expects the closing to occur in December 2002. The proceeds from the sale are expected to exceed the book value of these assets.

After a review of Enogex’s assets on the basis of their strategic value and other factors, the Company has decided to sell the interests of its subsidiary, Enogex Products Corporation, in the west Texas properties consisting of the NuStar Joint Venture (“NuStar”) which has operations consisting of the extraction and sale of natural gas liquids. NuStar’s book value was

approximately $36.7 million at September 30, 2002 and Enogex has received preliminary non-binding bids exceeding NuStar’s book value. Enogex expects the sale to be completed in early 2003. These assets are part of the Energy Supply segment.

The Condensed Consolidated Financial Statements of the Company have been restated to reflect the disposition of NuStar and Enogex’s exploration and production assets and their treatment as discontinued operations meet the definition of a component of an entity in accordance with SFAS No. 144. Accordingly, revenues, costs and expenses, assets, liabilities and cash flows of the exploration and production assets and NuStar have been excluded from the respective captions in the Condensed Consolidated Financial Statements and have been reported as “Current Assets of Discontinued Operations”, “Net Property, Plant and Equipment of

Discontinued Operations", "Deferred Charges and Other Assets of Discontinued Operations", "Current Liabilities of Discontinued Operations", "Deferred Credits and Other Liabilities of Discontinued Operations", "Income from Discontinued Operations" and "Net Cash Provided from Discontinued Operations."

Summarized financial information for the discontinued operations is as follows:

STATEMENTS OF INCOME DATA

(In millions)	Three Months Ended September 30, 2002	Three Months Ended September 30, 2001	Nine Months Ended September 30, 2002	Nine Months Ended September 30, 2001
Operating revenues from discontinued operations.........	**$ 19.1**	$ 20.2	**$ 58.0**	$ 80.0
Income from discontinued operations before taxes..	**$ 0.1**	$ 0.1	**$ 3.6**	$ 12.5

BALANCE SHEET DATA

(In millions)	September 30, 2002	December 31, 2001
Cash and cash equivalents..	**$ 4.2**	$ ---
Accounts receivable - customers..	**3.5**	6.9
Prepayments..	**---**	0.9
Other current assets...	**0.3**	0.2
Total current assets of discontinued operations....................	**$ 8.0**	$ 8.0
Plant in service of discontinued operations.........................	**110.2**	135.2
Less accumulated depreciation....................................	**40.4**	48.3
Net property, plant and equipment of discontinued operations........	**$ 69.8**	$ 86.9
Other deferred charges and other assets..............................	**0.8**	0.7
Total deferred charges and other assets of discontinued operations..	**$ 0.8**	$ 0.7
Accounts payable...	**4.1**	2.7
Accrued taxes	**0.3**	0.4
Total current liabilities of discontinued operations...............	**$ 4.4**	$ 3.1
Other deferred credits and other liabilities.........................	**9.4**	10.5
Total deferred credits and other liabilities of discontinued operations...	**$ 9.4**	$ 10.5

6. Asset Disposals

In March 2002, Enogex sold all of its interests in Belvan Corporation, Belvan Limited Partnership and Todd Ranch Limited Partnership to West Texas Gas, Inc. for approximately $9.8 million and recognized a gain of $1.6 million. Belvan Limited Partnership and Todd Ranch Limited Partnership had approximately 344 miles of gathering lines in Crockett and Pecos counties in Texas. Enogex had acquired these entities in 1998.

On August 2, 2002, Ozark Gas Transmission, L.L.C. ("Ozark"), in which an Enogex subsidiary owns a 75 percent interest, entered into an Agreement of Sale and Purchase with Reliant Energy Gas Transmission Company to sell 30 miles of transmission lines of the Ozark pipeline located in Pittsburg and Latimer counties in Oklahoma. The closing is subject to FERC approval and is expected to occur by December 31, 2002. The proceeds to be recognized by Ozark from the sale are expected to be approximately $10.0 million.

7. Long-Term Debt

During 2001, the Company entered into two separate interest rate swap agreements: (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 an interest rate swap agreement, effective July 15, 2001, to convert $200.0 million of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the three month

LIBOR. On March 1, 2002, Enogex monetized its interest rate swap agreement and received cash of $4.2 million, which will be amortized over the life of the related debt.

On March 4, 2002, Enogex entered into a new interest rate swap agreement to convert $200.0 million of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the three month LIBOR. On July 2, 2002, Enogex monetized its interest rate swap agreement and received cash of $6.6 million, of which $3.2 million was recorded against interest receivable and the remaining amount of $3.4 million will be amortized over the remaining life of the related debt.

On August 7, 2002, Enogex entered into a new interest rate swap agreement to convert $100.0 million of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the six month LIBOR.

These interest rate swaps qualified as fair value hedges under SFAS No. 133 and meet all of the requirements for a determination that there was no ineffective portion as allowed by the shortcut method under SFAS No. 133. The objective of these interest rate swaps was to achieve a lower cost of debt and raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standard.

Enogex retired $83.0 million of long-term debt that matured during the three months ended September 30, 2002. This debt consisted of $3.0 million principal amount of 7.02 percent medium-term notes due August 7, 2002, $35.0 million principal amount of 7.04 percent medium-term notes due August 7, 2002, $25.0 million principal amount of 7.05 percent medium-term notes due August 7, 2002, $1.0 million principal amount of 7.33 percent medium-term notes due august 26, 2002, $5.0 million principal amount of 7.35 percent medium-term notes due August 26, 2002 and $14.0 million principal amount of 7.32 percent medium-term notes due August 26, 2002.

8. Commitments and Contingencies

OG&E Rate Case

In September 2001, the director of the OCC public utility division filed an application with the OCC to review the rates of OG&E. On January 28, 2002, OG&E filed its response requesting a $22.0 million annual rate increase. Approximately $10.3 million of the requested rate increase related to enhanced security as a result of the September 11, 2001 terrorist attacks and approximately $11.7 million related to increased capacity needs and system reliability.

On January 30, 2002, a significant ice storm hit OG&E’s service territory and inflicted major damage to the transmission and distribution infrastructure with total expenditures of approximately $92.0 million. The ice storm affected approximately 195,000 of OG&E’s

customers and approximately 15,000 square miles of OG&E’s service territory. The area of damage was within counties that were declared a federal disaster area. Of the $92.0 million, approximately $86.6 million was related to capital expenditures and $5.4 million was related to operating expenditures. The capital expenditures of approximately $86.6 million have been recorded as part of OG&E’s Property, Plant and Equipment. The approximately $5.4 million in operating expenditures have been deferred. On July 1, 2002, OG&E filed direct testimony in support of recovery for the $5.4 million of deferred operating costs over three years.

In October 2002, OG&E settled the rate case, including recovery of the capital expenditures and deferred operating costs associated with the ice storm. See Note 11 for a further discussion.

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

OG&E entered into an agreement with the parent company of Central Oklahoma Oil and Gas Corp. (“COOG”), an unrelated third-party, to develop a natural gas storage facility (the “Storage Facility”). During 1996, OG&E completed negotiations and contracted with COOG for gas storage services from the Storage Facility. Pursuant to the storage contract, COOG reimbursed OG&E for all outstanding cash advances and interest amounting to approximately $46.8 million. In 1997, COOG obtained permanent financing for the Storage Facility and issued a note (the “COOG Note”) to an unaffiliated third-party. The original amount of the COOG Note was $49.5 million. As part of the arrangement for the permanent financing, the Company agreed, upon the occurrence of a monetary default by COOG on the COOG Note, to purchase the COOG Note from the holders at a price equal to the unpaid principal and interest under the COOG Note.

In July 1998, Enogex entered into a Storage Lease Agreement with COOG (“Enogex Storage Agreement”) whereby Enogex agreed to lease underground gas storage from COOG, with the capacity being developed by COOG. At September 30, 2002, the capital lease obligation was $9.3 million. As part of the Enogex Storage Agreement, Enogex was granted an option to purchase the Storage Facility. Also as part of the Enogex Storage Agreement, the Company agreed to make up to a $12.0 million secured loan to an affiliate of COOG (the “COOG Affiliate Loan”). At September 30, 2002, the amount outstanding under the COOG Affiliate Loan is $8.0 million. The COOG Affiliate Loan was originally repayable in 2003 and was secured by the assets and stock of COOG. This loan is classified as Other Property and Investments on the books of the Company. While the Company fully believes it will collect all amounts receivable under the COOG Affiliate Loan in the event the COOG affiliate is unable to pay the COOG Affiliate Loan, the Company would be required to write off the portion of such loan that is not repaid and which cannot be offset against other COOG liabilities.

In 2001, disputes arose under the Enogex Storage Agreement between Enogex and COOG. The parties arbitrated these disputes pursuant to the terms of the Enogex Storage Agreement. The arbitration panel rendered a decision in favor of Enogex on February 8, 2002 in the amount of $23.3 million ("Arbitration Award"). This amount has not been recorded as a receivable in the Condensed Consolidated Financial Statements at September 30, 2002.

By letter dated May 9, 2002, COOG advised the holder of the COOG Note that the Arbitration Award was in excess of $10.0 million and, in the event the Arbitration Award became a final, non-appealable order, it would constitute an event of default under the COOG Note. COOG also advised the holder of its note that, due to the significant expenses incurred in defending the Arbitration Award, it was unable to make the payment of principal and interest on the note due May 1, 2002. As a result, the Company made the May 2002 principal and interest payment of approximately $1.0 million and also was required to purchase the note at a price equal to its unpaid principal and interest of approximately $33.8 million. As the holder of the note, the Company is a secured creditor, with a first mortgage or comparable security interest on the Storage Facility.

On July 12, 2002, the District Court of Oklahoma County confirmed the Arbitration Award and entered a judgment in the amount of $23.3 million in favor of Enogex and against COOG (the "Judgment"). On August 9, 2002, COOG appealed the Judgment to the Oklahoma Supreme Court. COOG did not, however, post a bond to stay the execution of the Judgment. Therefore, on July 24, 2002, Enogex exercised its option to purchase the Storage Facility, escrowed the transfer documentation and set closing for July 31, 2002. Enogex offset the $4.5 million purchase price against the Judgment. After taking into account this set off, there were no funds remaining to reduce the COOG affiliate's obligation to the Company under the $8.0 million COOG Affiliate Loan. COOG did not execute the transfer documentation by July 31, 2002. On August 7, 2002, COOG agreed to turn over operations of the Storage Facility to Enogex. Enogex took over operation of the Storage Facility on August 9, 2002 and asserted ownership of the Storage Facility, pursuant to the terms of its original exercise of the purchase option.

In order to try and collect the remaining amounts owed under the Judgment, Enogex served a post-judgment garnishment on OG&E, as garnishee, on August 1, 2002, for all sums due to COOG under OG&E's storage contract with COOG. This garnishment resulted in a collection by Enogex of approximately $1.0 million from OG&E and this amount will be credited as partial satisfaction of the remaining Judgment amount. OG&E believes the remaining lease payments under its contract with COOG (now Enogex) is still recoverable through rates.

On September 18, 2002, Enogex filed an application seeking to have the Oklahoma Court resolve certain issues relating to the satisfaction of the Judgment. The Company recently became aware of a legal proceeding that has been filed by COOG and the COOG Affiliate against the Company and Enogex in Texas. The Company has asserted that it has not been properly served and that the Texas Court does not have proper jurisdiction over the Company. On September 24, 2002, Enogex filed a response to the allegations. It is the Company's position, among other things, that the disputed issues have already been properly determined by the arbitration panel and the Oklahoma Court and, therefore, the Texas action is improper. See Note 11 for a further discussion related to this dispute.

FERC Section 311 Rate Case

In December 2001, Enogex made its filing at FERC under Section 311 of the Natural Gas Policy Act to establish (for the combined Enogex-Transok system) rates and a treating fee and to

address various other issues, effective January 1, 2002. The FERC Staff, Enogex and the active intervening parties have initiated settlement discussions. Enogex has negotiated a settlement of all issues (in principle) with five parties and continues to negotiate with one other party. The outstanding, unresolved issues with the single party are relatively narrow and Enogex is hopeful that the parties will be able to resolve these issues in the near future in order to file and receive FERC acceptance of a complete settlement of this case by year-end 2002.

Firm Transportation Contract with Calpine Energy Services, L.P.

In 2000, Enogex entered into long-term firm transportation contracts with an independent power producer relating to a plant to be built in Wagoner County, Oklahoma. Effective July 1, 2000 the contracts were assigned to Calpine Energy Services, L.P. ("Calpine Energy"). In February 2002, Enogex requested a prepayment from Calpine Energy due to Calpine Energy falling below the contractual creditworthiness provisions of the transportation contract. Calpine Energy is refusing to make certain payments for the monthly demand fees pursuant to the transportation contracts on grounds of an alleged force majeure event. Enogex also made a demand on Calpine Corporation, as guarantor, relating to Calpine Energy's failure to make the required prepayment and demand payments. As of September 30, 2002 the amount of demand revenues due to Enogex was approximately $3.4 million, which have been fully reserved on the Company's financial statements. Enogex also asserts that Calpine Corporation is liable for the amounts due and owing under the transportation agreements pursuant to the guarantee executed by Calpine Corporation, the parent corporation.

Calpine Energy and Calpine Corporation filed a declaratory judgment action in the United States District Court for the Northern District of Oklahoma relating to this dispute in September, 2002. Calpine Energy seeks a declaratory judgment that demand charges are not due and owing and that Enogex had no reasonable ground to question its creditworthiness under the contracts. Enogex disagrees with Calpine Energy's assertions and plans to assert a request for declaratory relief that such demand fees are due and owing.

9. Earnings Per Share

The reconciliation of the numerator and denominator used for the computation of basic and diluted earnings per share is as follows:

	Three Months Ended September 30, 2002	Three Months Ended September 30, 2001	Nine Months Ended September 30, 2002	Nine Months Ended September 30, 2001
	(In millions, except per share data)			
Income From Continuing Operations..........	**$ 96.7**	$ 96.5	**$ 114.5**	$ 97.1
Income From Discontinued Operations........	**2.3**	0.6	**6.7**	9.8
Net Income.................................	**$ 99.0**	$ 97.1	**$ 121.2**	$ 106.9
Average Common Shares Outstanding				
Shares for basic earnings per average common share...........................	**78.1**	77.9	**78.0**	77.9
Effect of dilutive securities:				
Employee stock options and unvested stock grants.........................	**---**	---	**0.1**	---
Adjusted average common shares outstanding for diluted earnings per average common share..................................	**78.1**	77.9	**78.1**	77.9
Basic earnings per average common share				
Income from continuing operations........	**$ 1.24**	$ 1.24	**$ 1.47**	$ 1.25
Income from discontinued operations, net of tax............................	**0.03**	0.01	**0.08**	0.12
Net Income...............................	**$ 1.27**	$ 1.25	**$ 1.55**	$ 1.37
Diluted earnings per average common share				
Income from continuing operations........	**$ 1.24**	$ 1.24	**$ 1.47**	$ 1.25
Income from discontinued operations, net of tax............................	**0.03**	0.01	**0.08**	0.12
Net Income...............................	**$ 1.27**	$ 1.25	**$ 1.55**	$ 1.37

Certain common shares subject to issuance related to employee stock options are not included in the calculation of adjusted average common shares outstanding for diluted earnings per average common share because the effect of including those shares is anti-dilutive.

10. Report of Business Segments

The Company's Electric Utility operations are conducted through OG&E, an operating public utility engaged in the generation, transmission, distribution and sale of electric energy. Energy Supply operations are conducted through Enogex. Enogex is engaged in transporting natural gas through its intra-state pipeline to various customers (including OG&E), gathering and processing natural gas and marketing electricity, natural gas and natural gas liquids. Enogex also has been involved in investing in the development for and production of natural gas and crude oil, which investments Enogex is now selling. Other Operations primarily include unallocated corporate expenses and interest expense on commercial paper. The following are the results for the Company's business segments.

Three Months Ended September 30, 2002	Electric Utility	Energy Supply (B)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues........................	$ 488.9	$ 137.9	$ ---	$ (14.1)(A)	$ 612.7
Fuel	140.4	---	---	(8.1)	132.3
Purchased power...........................	66.9	---	---	---	66.9
Gas purchased for resale..................	---	69.7	---	(6.0)	63.7
Natural gas purchases - other.............	---	14.0	---	---	14.0
Cost of goods sold........................	207.3	83.7	---	(14.1)	276.9
Gross margin on revenues..................	281.6	54.2	---	---	335.8
Other operation and maintenance...........	68.9	23.6	(3.6)	---	88.9
Depreciation and amortization.............	30.9	12.1	2.5	---	45.5
Taxes other than income...................	11.6	3.3	0.7	---	15.6
Operating income..........................	170.2	15.2	0.4	---	185.8

	Electric Utility	Energy Supply	Other Operations	Intersegment	Total
Other income..............................	0.5	0.5	---	---	1.0
Other expense.............................	(1.1)	---	(0.6)	---	(1.7)
Earnings (loss) before interest and taxes.	$ 169.6	$ 15.7	$ (0.2)	$ ---	$ 185.1
Income (loss) from continuing operations..	$ 98.4	$ 1.8	$ (3.5)	$ ---	$ 96.7
Income from discontinued operations.......	---	2.3	---	---	2.3
Net income (loss).........................	$ 98.4	$ 4.1	$ (3.5)	$ ---	$ 99.0

(A) Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations.

(B) Beginning with the first quarter of 2002, Energy Supply's operations have been reported into four activities: Transportation and Storage, Gathering and Processing, Marketing and Trading and Exploration and Production. The following is supplemental Energy Supply information.

	Transportation and Storage	Gathering and Processing (C)	Marketing and Trading	Exploration and Production(C)	Eliminations	Total
(In millions)						
Operating revenues...............	$ 101.9	$ 45.9	$ 1.5	$ ---	$ (11.4)	$137.9
Earnings (loss) before interest and taxes......................	$ 16.4	$ 1.4	$ (2.1)	$ ---	$ ---	$ 15.7

(C) NuStar, which is part of Gathering and Processing, and Exploration and Production have been reflected as discontinued operations and therefore, have no impact on earnings (loss) before interest and taxes ("EBIT").

Three Months Ended September 30, 2001	Electric Utility	Energy Supply	Other Operations	Intersegment	Total(D)
(In millions)					
Operating revenues........................	$ 508.1	$ 157.2	$ ---	$ (9.3)(A)	$ 656.0
Fuel	155.1	---	---	(9.1)	146.0
Purchased power...........................	70.6	---	---	---	70.6
Gas purchased for resale..................	---	79.2	---	(0.2)	79.0
Natural gas purchases - other.............	---	26.4	---	---	26.4
Cost of goods sold........................	225.7	105.6	---	(9.3)	322.0
Gross margin on revenues..................	282.4	51.6	---	---	334.0
Other operation and maintenance...........	69.5	23.2	(4.8)	---	87.9
Depreciation and amortization.............	29.2	11.6	1.9	---	42.7
Taxes other than income...................	11.4	4.0	0.6	---	16.0
Operating income..........................	172.3	12.8	2.3	---	187.4
Other income..............................	0.3	0.3	---	---	0.6
Other expense.............................	(0.6)	(0.1)	(0.1)	---	(0.8)
Earnings before interest and taxes........	$ 172.0	$ 13.0	$ 2.2	$ ---	$ 187.2
Income (loss) from continuing operations..	$ 100.1	$ (0.6)	$ (3.0)	$ ---	$ 96.5
Income from discontinued operations.......	---	0.6	---	---	0.6
Net income (loss).........................	$ 100.1	$ ---	$ (3.0)	$ ---	$ 97.1

(A) Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations.

(D) These amounts have been restated as described in Notes 2 and 5.

Nine Months Ended September 30, 2002	Electric Utility	Energy Supply(B)	Other Operations	Intersegment	Total

(In millions)					
Operating revenues	$ 1,103.2	$ 420.4	$ ---	$ (35.2)(A)	$ 1,488.4
Fuel	338.2	---	---	(25.6)	312.6
Purchased power	196.0	---	---	---	196.0
Gas purchased for resale	---	213.0	---	(9.6)	203.4
Natural gas purchases - other	---	55.4	---	---	55.4
Cost of goods sold	534.2	268.4	---	(35.2)	767.4
Gross margin on revenues	569.0	152.0	---	---	721.0
Other operation and maintenance	209.1	71.8	(10.1)	---	270.8
Depreciation and amortization	91.9	37.2	7.6	---	136.7
Taxes other than income	35.2	11.6	1.9	---	48.7
Operating income	232.8	31.4	0.6	---	264.8
Other income	1.2	2.5	---	---	3.7
Other expense	(3.0)	(0.2)	(0.5)	---	(3.7)
Earnings before interest and taxes	$ 231.0	$ 33.7	$ 0.1	$ ---	$ 264.8
Income (loss) from continuing operations	$ 127.7	$ (2.9)	$ (10.3)	$ ---	$ 114.5
Income from discontinued operations	---	6.7	---	---	6.7
Net income (loss)	$ 127.7	$ 3.8	$ (10.3)	$ ---	$ 121.2

(A) Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations.

(B) Beginning with the first quarter of 2002, Energy Supply's operations have been reported into four activities: Transportation and Storage, Gathering and Processing, Marketing and Trading and Exploration and Production. The following is supplemental Energy Supply information.

	Transportation and Storage	Gathering and Processing (C)	Marketing and Trading	Exploration and Production(C)	Eliminations	Total
(In millions)						
Operating revenues	$ 307.5	$ 133.4	$ 12.2	$ ---	$ (32.7)	$420.4
Earnings (loss) before interest and taxes	$ 36.6	$ (0.9)	$ (2.0)	$ ---	$ ---	$ 33.7

(C) NuStar, which is part of Gathering and Processing, and Exploration and Production have been reflected as discontinued operations and therefore, have no impact on EBIT.

Nine Months Ended September 30, 2001	Electric Utility	Energy Supply	Other Operations	Intersegment	Total(D)
(In millions)					
Operating revenues	$ 1,194.5	$ 548.8	$ ---	$ (32.9)(A)	$ 1,710.4
Fuel	401.5	---	---	(27.2)	374.3
Purchased power	218.0	---	---	---	218.0
Gas purchased for resale	---	296.2	---	(5.7)	290.5
Natural gas purchases - other	---	126.2	---	---	126.2
Cost of goods sold	619.5	422.4	---	(32.9)	1,009.0
Gross margin on revenues	575.0	126.4	---	---	701.4
Other operation and maintenance	213.0	69.5	(10.3)	---	272.2
Depreciation and amortization	89.8	34.2	5.6	---	129.6
Taxes other than income	34.5	12.3	1.9	---	48.7
Operating income	237.7	10.4	2.8	---	250.9
Other income	3.2	1.3	0.2	---	4.7
Other expense	(4.8)	(0.1)	(0.2)	---	(5.1)
Earnings before interest and taxes	$ 236.1	$ 11.6	$ 2.8	$ ---	$ 250.5

Income (loss) from continuing operations..	$ 127.1	$ (19.7)	$ (10.3)	$ ---	$ 97.1
Income from discontinued operations.......	---	9.8	---	---	9.8
Net income (loss)..........................	$ 127.1	$ (9.9)	$ (10.3)	$ ---	$ 106.9

(A) Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations.

(D) These amounts have been restated as described in Notes 2 and 5.

11. Subsequent Events

Long-Term Debt

On October 24, 2002, Enogex entered into a new interest rate swap agreement to convert $100.0 million of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the six month LIBOR. This interest rate swap qualified as a fair value hedge 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. The objective of this interest rate swap was to achieve a lower cost of debt and raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standard.

Commitments and Contingencies

OG&E Rate Case

As discussed in Note 8, in response to a request from the OCC, OG&E filed for a rate increase. On October 11, 2002, OG&E, the OCC Staff, the Oklahoma Attorney General and other interested parties agreed to a settlement (the “Settlement Agreement”) of OG&E’s rate case. The administrative law judge subsequently recommended approval of the Settlement Agreement. The Settlement Agreement provides, among other items: (i) a $25.0 million annual reduction in the electric rates of OG&E’s Oklahoma customers which begins with the first regular billing cycle occurring 41 days after the issuance of the OCC order approving the Settlement Agreement; (ii) recovery by OG&E, through rate base, of the capital expenditures associated with the January 2002 ice storm; (iii) 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 of electricity to other utilities and power marketers; (iv) OG&E to acquire electric generating capacity (“New Generation”) of not less than 400 Megawatts to be integrated into OG&E’s generation system. The Settlement Agreement remains subject to the review and approval of the three commissioners of the OCC. The OCC will meet in November 2002 to review the Settlement Agreement. See “Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations-Regulation and Rates-Recent Regulatory Matters” for further discussion of these developments.

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

On October 24, 2002, Enogex, the Company, Natural Gas Storage Corporation and COOG entered into a standstill agreement. As part of this agreement, (i) COOG executed the closing documents relating to the Storage Facility and assigned title to the Storage Facility to Enogex; (ii) the Company agreed to provide information relating to the storage field; (iii) the parties agreed to stay the pending litigation matters for an initial 45 day period to allow the parties the opportunity to draft and execute an escrow agreement whereby COOG would deposit $5.0 million into escrow by the end of the initial 45 day period; (iv) the parties agreed that if COOG deposited the required $5.0 million pursuant to the executed escrow agreement, the litigation would be stayed for a second 45 day period; during which the parties would determine if a mutually agreeable purchase and sale agreement providing for the repurchase of the facility by COOG could be negotiated and executed; (v) if a purchase agreement is executed during the second 45 day period, the parties agreed that the litigation would be stayed for a third 45 day period from the date of the signing of the purchase agreement and if the purchase agreement fully closed prior to the end of the third 45 day period, the $5.0 million escrowed funds would be applied against the purchase price; (vii) the parties agreed that if the purchase agreement was not executed during the second 45 day period or if the closing did not occur prior to the end of the third 45 day period, the funds would become the property of Enogex; and (viii) the parties agreed that upon such closing or turnover of the escrowed funds, the parties would exchange mutual full releases of all liabilities.

Firm Transportation Contract with Calpine Energy Services, L.P.

As discussed in Note 8, Calpine Energy and Calpine Corporation filed a declaratory judgment action regarding the status of their respective obligations under a transportation contract and a guarantee. Enogex answered and filed its counterclaim against Calpine Energy and Calpine Corporation on October 8, 2002. Enogex denied that either of the Calpine entities was entitled to the declaratory judgment requested. Enogex sought, under the counterclaim: (i) an award based on breach of the contracts and the guarantee; (ii) a declaration that damages were due and owing under the contracts and the guarantee and; (iii) a prepayment by Calpine Energy to Enogex be maintained pursuant to the contracts.

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 Energy Supply 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 the jurisdiction of the Oklahoma Corporation Commission ("OCC"), the Arkansas Public Service Commission ("APSC") and the Federal Energy Regulatory Commission ("FERC"). OG&E sold its retail gas business in 1928 and is no longer engaged in the gas distribution business. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area, which is the second largest market and an area of high growth in that state. OG&E is expected to grow moderately, consistent with historic trends. Expansion will primarily result from continued economic growth in its service territory.

The Energy Supply segment produces, gathers, processes, transports, markets and stores natural gas; produces, transports and markets natural gas liquids; provides commodity sales and services related to natural gas and electric power; and provides energy-related services for corporate commodity price risk management and energy forward price evaluations. These operations are conducted through Enogex Inc. and its subsidiaries ("Enogex"). Within the Energy Supply segment, Enogex's activities are further subdivided into four categories: transportation and storage; gathering and processing; marketing and trading; and exploration and production (which exploration and production assets are in the process of being sold).

Enogex owns and operates the tenth largest natural gas pipeline system in the United States in terms of miles of pipe in service. Enogex has a significant investment in natural gas gathering, processing, transmission and storage in the major gas producing basins of Oklahoma.

During 2002, Enogex has evaluated, redesigned and reorganized around their internal work processes in order to achieve cost reductions and revenue enhancements within their businesses. Enogex is beginning to see the positive results of these efforts and expects continued improvements during the fourth quarter of 2002 and during 2003.

Forward-Looking Statements

Except for the historical statements contained herein, the matters discussed in this Form 10-Q, including the discussion in "2002 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", "estimate", "objective",

"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 their impact on capital expenditures; 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; state and federal legislative 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, finalization of the Settlement Agreement; changes in accounting guidelines; creditworthiness of suppliers, customers and other contractual parties and other risk factors listed in the Company's Form 10-K for the year ended December 31, 2001, including Exhibit 99.01 thereto and other factors described from time to time in the Company's reports filed with the Securities and Exchange Commission.

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, 2002 as compared to the three and nine months ended September 30, 2001 and the Company's consolidated financial position at September 30, 2002. Due to seasonal fluctuations and other factors, the operating results for the three and nine months ended September 30, 2002 are not necessarily indicative of the results that may be expected for the year ending December 31, 2002 or for any future period. Known trends and contingencies of a material nature are discussed to the extent considered relevant.

Operating Results

The Company reported earnings of $1.27 per share for the three months ended September 30, 2002 compared to earnings of $1.25 per share for the same period in 2001 and earnings of $1.55 per share for the nine months ended September 30, 2002 compared to earnings of $1.37 per share for the same period in 2001. The improvement in financial performance was primarily due to an increase in gross margins and lower interest expenses. Earnings from continuing operations were $1.24 per share for the three months ended September 30, 2002 and 2001 primarily due to an increase in gross margins, lower interest expenses offset by higher depreciation and amortization expense, higher operation and maintenance expenses and higher income tax expense. Earnings from continuing operations were $1.47 per share for the nine months ended September 30, 2002 compared to $1.25 per share for the same period in 2001. The improvement in financial performance was primarily due to an increase in gross margins and lower interest expenses partially offset by higher depreciation and amortization expense and higher income tax expense.

OG&E contributed $1.26 per share for the three months ended September 30, 2002 compared to $1.29 per share for the same period in 2001. OG&E's decrease was primarily attributable to lower levels of natural gas transportation cost recovered, lower recoveries of fuel costs from Arkansas customers and lower kilowatt-hour sales to other utilities and power marketers ("off-system sales") partially offset by milder weather and increased growth in OG&E's service territory, lower operation and maintenance expenses and lower interest expense.

Enogex contributed $0.05 per share for the three months ended September 30, 2002 compared to $0.00 per share for the same period in 2001. Enogex's improvement was primarily

attributable to increased margins in transportation and storage and marketing and trading partially offset by a decreased margin in gathering and processing due to lower processing sales volumes and less favorable fractionation spreads partially offset by increased gathering revenues. Also contributing to Enogex's improvement was lower net interest expense for the three months ended September 30, 2002. Enogex's exploration and production assets and its interest in the NuStar Joint Venture ("NuStar") have been reported as discontinued operations for the three months ended September 30, 2002 and 2001. Earnings from discontinued operations were $0.03 per share for the three months ended September 30, 2002 compared to $0.01 per share for the same period in 2001. This improvement was primarily attributable to an increased margin related to NuStar as the margin for exploration and production remained flat for the three months ended September 30, 2002 as compared to the same period in 2001. See Note 5 to the Condensed Consolidated Financial Statements for a further discussion.

The results on a stand-alone basis of the Company (i.e., as a holding company), which has expenses but no revenues, reflect a loss of $0.04 per share for the three months ended September 30, 2002 and 2001.

OG&E contributed $1.64 per share for the nine months ended September 30, 2002 compared to $1.63 per share for the same period in 2001. OG&E's improvement was primarily attributable to lower operation and maintenance expenses, lower interest expense milder weather and increased growth in OG&E's service territory, partially offset by lower recoveries of fuel costs from Arkansas customers, lower levels of natural gas transportation cost recovered, loss of revenue resulting from the January 2002 ice storm and lower kilowatt-hour sales of off-system sales.

Enogex contributed $0.04 per share for the nine months ended September 30, 2002 compared to a loss of $0.13 per share for the same period in 2001. Enogex's improvement was primarily attributable to increased margins in transportation and storage and marketing and trading partially offset by a decreased margin in gathering and processing due to lower sales volumes for gathering and processing partially offset by a gain resulting from the sale of assets and more favorable fractionation spreads. Also contributing to Enogex's improvement was lower net interest expense for the nine months ended September 30, 2002. Enogex's exploration and production assets and its interest in NuStar have been reported as discontinued operations for the nine months ended September 30, 2002 and 2001. Earnings from discontinued operations were $0.08 per share for the nine months ended September 30, 2002 compared to $0.12 per share for the same period in 2001. This decrease was primarily attributable to a decreased margin for exploration and production partially offset by an increased margin related to NuStar. See Note 5 to the Condensed Consolidated Financial Statements for a further discussion.

The results on a stand-alone basis of the Company (i.e., as a holding company) reflect a loss of $0.13 per share for the nine months ended September 30, 2002 and 2001.

Regulatory Considerations

Actions of the regulatory commissions that set OG&E's electric rates will continue to affect the Company's financial results. Reference is made to "Regulation and Rates-Recent Regulatory Matters" for a discussion of recent actions relating to OG&E's rates.

OG&E has been and will continue to be affected by competitive changes to the utility industry. Significant changes already have occurred in the wholesale electric markets at the federal level and significant changes are possible at the retail level in the states served by the Company. In Oklahoma, deregulation of the electric industry has been postponed until at least 2003. See "Regulation and Rates-State Restructuring Initiatives" for further discussion of these developments.

Asset Disposals

In March 2002, Enogex sold all of its interests in Belvan Corporation, Belvan Limited Partnership and Todd Ranch Limited Partnership to West Texas Gas, Inc. for approximately $9.8 million and recognized a gain of $1.6 million. Belvan Limited Partnership and Todd Ranch Limited Partnership had approximately 344 miles of gathering lines in Crockett and Pecos counties in Texas. Enogex had acquired these entities in 1998.

On August 2, 2002, Ozark Gas Transmission, L.L.C. ("Ozark"), in which an Enogex subsidiary owns a 75 percent interest, entered into an Agreement of Sale and Purchase with Reliant Energy Gas Transmission Company to sell 30 miles of transmission lines of the Ozark pipeline located in Pittsburg and Latimer counties in Oklahoma. The closing is subject to FERC approval and is expected to occur by December 31, 2002. The proceeds to be recognized by Ozark from the sale are expected to be approximately $10.0 million.

Commitments and Contingencies

See Notes 8 and 11 to the Condensed Consolidated Financial Statements for a description of certain commitments and contingencies, including disputes with Central Oklahoma Oil and Gas Corp. and Calpine Energy Services, L.P.

2002 Outlook

The Company projected 2002 earnings at $1.40 to $1.50 per share based on the mild weather during 2002 in the Electric Utility segment and the continuing weak commodity price environment. The Company expects to maintain its annual dividend of $1.33 per share in 2002 and 2003. The Company's earnings estimate for 2002 does not include any of the approximately

$92.0 million in expenditures associated with the January 2002 ice storm, which, as discussed previously, are currently being capitalized or deferred.

Results of Operations

(In millions, except per share data)	Three Months Ended September 30, **2002**	Three Months Ended September 30, 2001	Nine Months Ended September 30, **2002**	Nine Months Ended September 30, 2001
Operating income	**$ 185.8**	$ 187.4	**$ 264.8**	$ 250.9
Earnings before interest and taxes	**$ 185.1**	$ 187.2	**$ 264.8**	$ 250.5
Basic average common shares outstanding	**78.1**	77.9	**78.0**	77.9
Diluted average common shares outstanding	**78.1**	77.9	**78.1**	77.9
Basic and diluted earnings per average common share	**$ 1.27**	$ 1.25	**$ 1.55**	$ 1.37
Dividends paid per share	**$ 0.3325**	$ 0.3325	**$ 0.9975**	$ 0.9975

In reviewing its operating results, the Company believes that it is appropriate to focus on operating income and earnings before interest and taxes ("EBIT") as reported on its Condensed Consolidated Statements of Income. For the three months ended September 30, 2002, operating income was $185.8 million compared to $187.4 million for the same period in 2001 and EBIT was $185.1 million compared to $187.2 million for the same period in 2001. For the nine months ended September 30, 2002, operating income was $264.8 million compared to $250.9 million for the same period in 2001 and EBIT was $264.8 million compared to $250.5 million for the same period in 2001. Amounts listed above do not include discontinued operations. See "Discontinued Operations" below.

EBIT by Business Segment

(In millions)	Three Months Ended September 30, **2002**	Three Months Ended September 30, 2001	Nine Months Ended September 30, **2002**	Nine Months Ended September 30, 2001
OG&E (Electric Utility)	**$ 169.6**	$ 172.0	**$ 231.0**	$ 236.1
Enogex (Energy Supply)	**15.7**	13.0	**33.7**	11.6
Other Operations (1)	**(0.2)**	2.2	**0.1**	2.8
Consolidated EBIT	**$ 185.1**	$ 187.2	**$ 264.8**	$ 250.5

(1) Other Operations primarily include unallocated corporate expenses.

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

OG&E

(In millions)	Three Months Ended September 30, **2002**	Three Months Ended September 30, 2001	Nine Months Ended September 30, **2002**	Nine Months Ended September 30, 2001
Operating revenues	**$ 488.9**	$ 508.1	**$ 1,103.2**	$ 1,194.5
Fuel	**140.4**	155.1	**338.2**	401.5
Purchased power	**66.9**	70.6	**196.0**	218.0
Gross margin on revenues	**281.6**	282.4	**569.0**	575.0
Other operating expenses	**111.4**	110.1	**336.2**	337.3
Operating income	**170.2**	172.3	**232.8**	237.7
Other income	**0.5**	0.3	**1.2**	3.2
Other expense	**(1.1)**	(0.6)	**(3.0)**	(4.8)
EBIT	**$ 169.6**	$ 172.0	**$ 231.0**	$ 236.1

System sales - MWH(a)	**7.5**	7.7	**19.1**	19.2
Off-system sales - MWH	**0.1**	0.1	**0.2**	0.3
Total sales - MWH	**7.6**	7.8	**19.3**	19.5

(a) Megawatt-hour

Quarter ended September 30, 2002 compared to Quarter ended September 30, 2001

OG&E's EBIT for the three months ended September 30, 2002 decreased approximately $2.4 million or 1.4 percent as compared to the same period in 2001. The decrease in EBIT was primarily attributable to lower levels of gas transportation cost recovered, lower recoveries of fuel costs from Arkansas customers and lower kilowatt-hour sales of off-system sales partially offset by milder weather and increased growth in OG&E's service territory and lower operation and maintenance expenses.

Gross margin on revenues ("gross margin") for the three months ended September 30, 2002 decreased approximately $0.8 million or 0.3 percent as compared to the same period in 2001. Lower levels of natural gas transportation cost that OG&E was allowed to recover from its customers decreased the gross margin by approximately $1.6 million for the three months ended September 30, 2002 as a result of the Acquisition Premium Credit Rider ("APC Rider"), the Gas Transportation Credit Rider ("GTAC Rider") and the termination of the Generation Efficiency Performance Rider ("GEP Rider") in June 2002. Lower recoveries of fuel costs from Arkansas customers through that state's automatic fuel adjustment clause decreased the gross margin by approximately $0.8 million. In Arkansas, recovery of fuel costs is subject to a bandwidth mechanism. If fuel costs are within the bandwidth range, recoveries are not adjusted on a monthly basis; rather they are reset annually on April 1. Lower kilowatt-hour sales of off-system sales decreased the gross margin by approximately $0.6 million for the three months ended September 30, 2002 as compared to the same period in 2001. Partially offsetting these

decreases was an increase of approximately $2.2 million for the three months ended September 30, 2002 as compared to the same period in 2001, due to milder weather and increased growth in OG&E's service territory.

Cost of goods sold for OG&E consists of fuel used in electric generation and purchased power. OG&E's electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for OG&E and its customers. For the three months ended September 30, 2002, fuel expense decreased approximately $14.7 million or 9.5 percent as compared to the same period in 2001 primarily due to an 11.5 percent decrease in the average cost of fuel per kilowatt-hour. Purchased power costs decreased approximately $3.7 million or 5.2 percent for the three months ended September 30, 2002 as compared to the same period in 2001 due to a 9.7 percent decrease in the cost of purchased energy.

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 and Arkansas, in both states the costs are passed through to customers with no ultimate benefit or 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 "Regulation and Rates-Recent Regulatory Matters."

Other operating expenses increased $1.3 million or 1.2 percent for the three months ended September 30, 2002 as compared to the same period in 2001. Other operating expenses include operating and maintenance expense, depreciation and amortization expense and taxes other than income. OG&E's operating and maintenance expense decreased approximately $0.6 million or 0.9 percent for the three months ended September 30, 2002 as compared to the same period in 2001. This decrease was primarily due to a decrease of approximately $1.5 million in employee pension and benefit costs, a decrease of approximately $0.6 million in bad debt expense, a decrease of approximately $0.2 million in professional services expense and a decrease of approximately $2.0 million in miscellaneous corporate expenses. Partially offsetting these decreases were increases of approximately $1.8 million in materials and supplies expense, approximately $1.6 million in contract labor costs and approximately $0.3 million in employee labor costs.

Depreciation and amortization expense increased approximately $1.7 million or 5.8 percent for the three months ended September 30, 2002 as compared to the same period in 2001 due to a higher level of depreciable plant. Taxes other than income increased approximately $0.2 million or 1.8 percent for the three months ended September 30, 2002 as compared to the same period in 2001 due to higher ad valorem tax accruals.

Other income includes revenue from contract work performed by OG&E, non-operating rental income and profit on the retirement of fixed assets. OG&E's other income increased

approximately $0.2 million or 66.7 percent for the three months ended September 30, 2002 as compared to the same period in 2001. This increase was primarily due to a $0.2 million increase in contract work performed by OG&E.

Other expense includes expenses associated with contract work performed by OG&E, loss on the retirement of fixed assets, chairitable donations and expenditures for certain civic, political and related activities. OG&E's other expense increased approximately $0.5 million or 83.3 percent for the three months ended September 30, 2002 as compared to the same period in 2001.

This increase was primarily due to a $0.2 million increase in expenses associated with contract work performed by OG&E and a $0.2 million increase in losses on the retirement of fixed assets.

Nine months ended September 30, 2002 compared to Nine months ended September 30, 2001

OG&E's EBIT for the nine months ended September 30, 2002 decreased approximately $5.1 million or 2.2 percent as compared to the same period in 2001. The decrease in EBIT was primarily attributable to lower recoveries of fuel costs from Arkansas customers, lower levels of natural gas transportation costs recovered, loss of revenue resulting from the January 2002 ice storm and lower kilowatt-hour sales of off-system sales partially offset by milder weather and increased growth in OG&E's service territory and lower operation and maintenance expenses.

Gross margin for the nine months ended September 30, 2002 decreased approximately $6.0 million or 1.0 percent as compared to the same period in 2001. Lower recoveries of fuel costs from Arkansas customers through that state's automatic fuel adjustment clause decreased the gross margin by approximately $9.5 million. Lower levels of natural gas transportation cost that OG&E was allowed to recover from its customers decreased the gross margin by approximately $3.6 million for the nine months ended September 30, 2002 as compared to the same period in 2001 as a result of the APC Rider, the GTAC Rider and the termination of the GEP Rider in June 2002. Although total expenditures from the January 2002 ice storm, of approximately $92.0 million, which have been capitalized or deferred, did not impact operating results, the related loss of revenue due to interrupted power to our customers resulted in a decrease in the gross margin of approximately $1.5 million for the nine months ended September 30, 2002. Lower kilowatt-hour sales of off-system sales decreased the gross margin by approximately $1.0 million for the nine months ended September 30, 2002 as compared to the same period in 2001. Partially offsetting these decreases was an increase of approximately $9.6 million for the nine months ended September 30, 2002 as compared to the same period in 2001 due to milder weather and increased growth in OG&E's service territory.

Cost of goods sold for OG&E decreased approximately $85.3 million or 13.8 percent for the nine months ended September 30, 2002 as compared to the same period in 2001. For the nine months ended September 30, 2002, fuel expense decreased $63.3 million or 15.8 percent as compared to the same period in 2001 primarily due to a 20.6 percent decrease in the average cost of fuel per kilowatt-hour. Purchased power costs decreased approximately $22.0 million or 10.1 percent for the nine months ended September 30, 2002 as compared to the same period in 2001

due to a 8.9 percent decrease in the volume of energy purchased and a 16.0 percent decrease in the cost of purchased energy.

Other operating expenses decreased $1.1 million or 0.3 percent for the nine months ended September 30, 2002 as compared to the same period in 2001. OG&E's operating and maintenance expense decreased approximately $3.9 million or 1.8 percent for the nine months ended September 30, 2002 as compared to the same period in 2001. This decrease was primarily due to a decrease of approximately $6.8 million in bad debt expense, a decrease of approximately $1.4 million in professional services expense and a decrease of approximately $5.4 million in miscellaneous corporate expenses. Partially offsetting these decreases were increases of approximately $3.8 million in contract labor costs, approximately $3.4 million in materials and supplies expense, approximately $1.6 million in employee labor costs and approximately $0.9 million in employee pensions and benefit costs.

Depreciation and amortization expense increased approximately $2.1 million or 2.3 percent for the nine months ended September 30, 2002 as compared to the same period in 2001 due to a higher level of depreciable plant. Taxes other than income increased approximately $0.7 million or 2.0 percent for the nine months ended September 30, 2002 as compared to the same period in 2001 due to higher ad valorem tax accruals.

OG&E's other income decreased approximately $2.0 million or 62.5 percent for the nine months ended September 30, 2002 as compared to the same period in 2001. This decrease was primarily due to a $1.9 million decrease in contract work performed by OG&E.

OG&E's other expense decreased approximately $1.8 million or 37.5 percent for the nine months ended September 30, 2002 as compared to the same period in 2001. This decrease was primarily due to a $1.7 million decrease in expenses associated with contract work performed by OG&E.

Enogex

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Dollars in millions)	**2002**	2001(f)	**2002**	2001(f)
Operating revenues..........................	**$ 137.9**	$ 157.2	**$ 420.4**	$ 548.8
Gas purchased for resale...................	**69.7**	79.2	**213.0**	296.2
Natural gas purchases - other..............	**14.0**	26.4	**55.4**	126.2
Gross margin on revenues...................	**54.2**	51.6	**152.0**	126.4
Other operating expenses...................	**39.0**	38.8	**120.6**	116.0
Operating income...........................	**15.2**	12.8	**31.4**	10.4
Other income...............................	**0.5**	0.3	**2.5**	1.3

Other expense	**---**	(0.1)	**(0.2)**	(0.1)
EBIT	**$ 15.7**	$ 13.0	**$ 33.7**	$ 11.6
Physical System Supply - MMcfd(a)	**1,760**	1,862	**1,686**	1,789
Natural gas processed - MMcfd	**590**	642	**509**	649
Natural gas liquids sold - million gallons	**78**	124	**242**	342
Average sales price per gallon	**$ 0.376**	$ 0.341	**$ 0.379**	$ 0.460
Fractionation spread per MMBtu(b)	**$ 1.460**	$ 1.825	**$ 1.063**	$ 0.973
Natural gas marketed - Bbtu(c)	**100,790**	68,405	**293,186**	209,810
Average sales price per Bbtu	**$ 3.010**	$ 2.890	**$ 2.943**	$ 5.005
Power marketed - MWH	**354,377**	415,500	**1,078,307**	1,137,086
Average sales price per MWH	**$ 31.220**	$ 43.106	**$ 28.601**	$ 46.180
Natural gas produced - Mmcfe(d)	**878**	1,308	**3,397**	4,103
Average sales price per Mcfe(e), net of hedging	**$ 3.235**	$ 1.965	**$ 2.953**	$ 4.867

(a) Million cubic feet per day.
(b) Million British thermal units.
(c) Billion British thermal units.
(d) Million cubic feet equivalent.
(e) Thousand cubic feet equivalent.
(f) These amounts have been restated as described in Notes 2 and 5 to the Condensed Consolidated Financial Statements.

Quarter ended September 30, 2002 compared to Quarter ended September 30, 2001

Enogex's EBIT for the three months ended September 30, 2002 increased approximately $2.7 million or 20.8 percent as compared to the same period in 2001. The increase was primarily attributable to increased margins in transportation and storage and marketing and trading partially offset by a decreased margin in gathering and processing. Enogex's exploration and production assets and its interest in NuStar have been reported as discontinued operations for the three

months ended September 30, 2002 and 2001. See "Overview-Discontinued Operations" for a further discussion.

During the three months ended September 30, 2002, the transportation pipeline and storage facilities contributed $16.4 million of the Enogex EBIT which was an increase of $3.9 million as compared to the same period in 2001. The increased contribution to EBIT is primarily due to a $1.7 million increase in interruptible and other revenues due to increased volumes for the three months ended September 30, 2002 as compared to the same period in 2001. Also contributing to the increased EBIT was a $1.2 million increase in storage revenues, a $1.2 million reduction in fuel expense due to better fuel recoveries in 2002, a $1.0 million increase in firm transportation revenues due to a new independent power producer (“IPP”) contract and a $0.9 million increase in mark-to-market gains on storage contracts. These increases were partially offset by a $2.0 million increase in operating expenses due to an increase in employee benefits for the three months ended September 30, 2002 as compared to the same period in 2001. The remaining $0.1 million decrease to EBIT is primarily from lower other income for the three months ended September 30, 2002 as compared to the same period in 2001.

During the three months ended September 30, 2002, marketing and trading posted a loss of $2.1 million to the Enogex EBIT, which was an improvement of $1.6 million as compared to the loss of $3.7 million for the same period in 2001. The increased contribution to EBIT is primarily due to a $6.7 million increase in mark-to-market gains on storage contracts for the three months ended September 30, 2002 as compared to the same period in 2001. This increase was partially offset by decreased natural gas sales margins of $3.9 million and a $1.2 million increase related to demand fees expense for the three months ended September 30, 2002 as compared to the same period in 2001. The trading activities are conducted throughout the year subject to a daily, monthly and annual trading stop loss limit of $4 million. The daily loss exposure is measured primarily using value at risk 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 Enogex’s EBIT.

During the three months ended September 30, 2002, gathering and processing contributed $1.4 million of the Enogex EBIT, which was a decrease of $2.8 million as compared to the same period in 2001. The decrease in EBIT is primarily due to lower processing sales volumes of 37 percent, which accounted for $4.7 million of the decrease in EBIT for the three months ended September 30, 2002 as compared to the same period in 2001 and a $1.6 million loss related to less favorable fractionation spreads during the three months ended September 30, 2002 as compared to the same period in 2001. Fractionation spreads are the value of liquids after they are processed out of natural gas, less the price of the gas itself. A significant percentage of Enogex’s volumes during the prior year period were processed under “keep whole” arrangements. Under these arrangements, and in order to keep its shippers whole on a Btu basis, Enogex was required to replace the Btu value of the liquids with natural gas at market prices. In order to minimize the impact of low fractionation spreads, ethane and propane were rejected whenever possible. During the three months ended September 30, 2002, 20.5 million gallons were rejected compared to 5.4 million gallons in the same period in 2001. The average fractionation spread realized for the three months ended September 30, 2002 was $1.460 per MMBtu compared to $1.825 per

MMBtu for the same period in 2001. These decreases were offset by a $1.1 million increase in the gathering revenues due to lower sales volumes of 13 percent and higher prices of 26 percent for the three months ended September 30, 2002 as compared to the same period in 2001, a $1.1 million decrease in taxes other than income and a $1.3 million decrease in operating expenses for the three months ended September 30, 2002 as compared to the same period in 2001.

Nine months ended September 30, 2002 compared to Nine months ended September 30, 2001

Enogex's EBIT for the nine months ended September 30, 2002 increased approximately $22.1 million or 190.5 percent as compared to the same period in 2001. The increase was primarily attributable to increased margins in transportation and storage and marketing and trading partially offset by a decreased margin in gathering and processing. Enogex's exploration and production assets and its interest in NuStar have been reported as discontinued operations for the nine months ended September 30, 2002 and 2001. See "Overview-Discontinued Operations" for a further discussion.

During the nine months ended September 30, 2002, the transportation pipeline and storage facilities contributed $36.6 million of the Enogex EBIT, which was an increase of $16.7 million as compared to the same period in 2001. The increased contribution to EBIT is primarily due to a $6.9 million increase in firm transportation revenues due to a new IPP contract and a reduction in fuel expense of $6.3 million due to better fuel recoveries in 2002. Also contributing to the increased EBIT was a $3.5 million increase in storage revenues, a $3.0 million increase in natural gas sales margins, a $1.6 million increase in interruptible and other revenues due to increased prices and a $1.0 million increase in mark-to-market gains on storage contracts for the nine months ended September 30, 2002 as compared to the same period in 2001. Partially offsetting these increases was a $3.6 million increase in operating expenses due to increases in the costs of employee benefits, a $0.9 million increase in depreciation and amortization expense and a $0.8 million increase in taxes other than income. The remaining $0.3 million decrease to EBIT is primarily from lower minority interest income partially offset by higher other income for the nine months ended September 30, 2002 as compared to the same period in 2001.

During the nine months ended September 30, 2002, marketing and trading posted a loss of $2.0 million to the Enogex EBIT, which was an improvement of $7.2 million as compared to the loss of $9.1 million for the same period in 2001. The increased contribution to EBIT is primarily due to a $7.0 million increase in mark-to-market gains on storage contracts for the nine months ended September 30, 2002 and increased natural gas sales margins of $6.3 million for the nine months ended September 30, 2002. These increases were partially offset by a $2.3 million increase related to demand fees expense, a $2.0 million increase in depreciation and amortization expense due to a write off due to renegotiation of a natural gas sales contract, a $1.2 million decrease in the power sales margins and a $0.8 million increase in operating expenses for the nine months ended September 30, 2002 as compared to the same period in 2001. The remaining $0.2 million increase to EBIT is due to lower taxes other than income for the nine months ended September 30, 2002 as compared to the same period in 2001. The trading activities are conducted throughout the year subject to a daily, monthly and annual trading stop loss limit of $4 million. The daily loss exposure is measured primarily using value at risk 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 Enogex's EBIT.

During the nine months ended September 30, 2002, gathering and processing posted a loss of $0.9 million to the Enogex EBIT, which was a decrease of $1.8 million as compared to the same period in 2001. The decrease in EBIT is primarily due to lower sales volumes of nine percent and 29 percent, respectively, for gathering and processing, which accounted for $8.5 million of the decrease in EBIT for the nine months ended September 30, 2002 as compared to the same period in 2001. This decrease in EBIT is partially offset by a $1.6 million gain resulting from the sale of Enogex's interest in Belvan Corporation, Belvan Limited Partnership and Todd Ranch Limited Partnership during the nine months ended September 30, 2002, a $2.2 million decrease in operating expenses, a $1.3 million decrease in taxes other than income and a $1.2 million gain related to more favorable fractionation spreads during the nine months ended September 30, 2002 as compared to the same period in 2001. In order to minimize the impact of low fractionation spreads, ethane and propane were rejected whenever possible. During the nine months ended September 30, 2002, 66.0 million gallons were rejected compared to 90.0 million gallons in the same period in 2001. The average fractionation spread realized for the nine months ended September 30, 2002 was $1.063 per MMBtu compared to $0.973 per MMBtu for the same period in 2001. The remaining $0.4 million increase to EBIT is primarily from higher processing fees partially offset by hedging losses for the nine months ended September 30, 2002 as compared to the same period in 2001.

Consolidated Net Interest Expense and Income Tax Expense

Net interest expense includes interest income, interest expense and other interest charges. Net interest expense decreased approximately $3.7 million or 11.9 percent for the three months ended September 30, 2002 as compared to the same period in 2001. This decrease was primarily due to a $1.5 million decrease in interest expense related to the retirement of $83.0 million in debt during the three months ended September 30, 2002 and a $1.1 million decrease due to recording the ineffective portion of an interest rate swap during the three months ended September 30, 2001. Also contributing to the decrease was a $0.7 million decrease in interest expense related to lower commercial paper borrowings during the three months ended September 30, 2002 and a $0.6 million decrease due to a reduction of interest expense from entering into interest rate swap agreements in 2001. The remaining $0.2 million increase is comprised of individually insignificant items.

Net interest expense decreased approximately $13.6 million or 14.2 percent for the nine months ended September 30, 2002 as compared to the same period in 2001. This decrease was primarily due to a $6.2 million decrease related to a reduction of interest expense from entering into interest rate swap agreements in 2001, a $4.2 million decrease in interest expense related to lower commercial paper borrowings during the nine months ended September 30, 2002 and a $2.6 million decrease in interest expense related to the retirement of $114.0 million in debt during the nine months ended September 30, 2002. Also contributing to the decrease was a $1.1 million decrease due to recording the ineffective portion of an interest rate swap during the nine

months ended September 30, 2001. The remaining $0.5 million increase is comprised of individually insignificant items.

Income tax expense increased approximately $1.4 million or 2.4 percent for the three months ended September 30, 2002 as compared to the same period in 2001 primarily from pre-tax income at Enogex for the three months ended September 30, 2002 compared to a pre-tax loss in the same period in 2001.

Income tax expense increased approximately $10.5 million or 18.3 percent for the nine months ended September 30, 2002 as compared to the same period in 2001 primarily from a lower pre-tax loss at Enogex for the nine months ended September 30, 2002. The overall higher income tax was partially offset as a result of the reversal of previously accrued federal income tax at a subsidiary of Enogex. The reversal of income tax expense was related to a disagreement between Enogex and the Internal Revenue Service, which was resolved in favor of Enogex. Also offsetting the increase was a refund of Oklahoma state income tax related to Oklahoma investment tax credits.

Discontinued Operations

On August 5, 2002, Enogex entered into an Agreement of Sale and Purchase with Chesapeake Exploration Limited Partnership to sell all of its exploration and production assets located in Oklahoma, Texas, Arkansas and Mississippi for approximately $15.0 million. The effective date of the sale was July 1, 2002 and the closing occurred on September 19, 2002. The Company recognized a $2.3 million loss related to the sale of these assets. These assets were part of the Energy Supply segment.

Enogex is currently negotiating the sale of its exploration and production assets located in Michigan and expects the closing to occur in December 2002. The proceeds from the sale are expected to exceed the book value of these assets.

After a review of Enogex’s assets on the basis of their strategic value and other factors, the Company has decided to sell the interests of its subsidiary, Enogex Products Corporation, in the west Texas properties consisting of NuStar which has operations consisting of the extraction and sale of natural gas liquids. NuStar’s book value was approximately $36.7 million at September 30, 2002 and Enogex has received preliminary non-binding bids exceeding NuStar’s book value. Enogex expects the sale to be completed in early 2003. These assets are part of the Energy Supply segment.

As a result of these sale transactions, Enogex’s exploration and production assets, including its Michigan assets, and NuStar have been reflected as discontinued operations in the accompanying Condensed Consolidated Financial Statements.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(In millions)	**2002**	2001	**2002**	2001
Operating revenues	**$ 19.1**	$ 20.2	**$ 58.0**	$ 80.0
Gas purchased for resale	**11.4**	13.9	**33.7**	47.6
Natural gas purchases - other	**1.4**	0.3	**4.9**	2.9
Gross margin on revenues	**6.3**	6.0	**19.4**	29.5
Other operating expenses	**3.7**	5.8	**13.2**	16.5
Operating income	**2.6**	0.2	**6.2**	13.0
Other income	**---**	0.2	**0.1**	0.2
Other expense	**(2.5)**	(0.3)	**(2.7)**	(0.8)
EBIT	**$ 0.1**	$ 0.1	**$ 3.6**	$ 12.4

Quarter ended September 30, 2002 compared to Quarter ended September 30, 2001

Gross margin for the three months ended September 30, 2002 increased approximately $0.3 million or 5.0 percent as compared to the same period in 2001. The increase was primarily attributable to an increase of approximately $1.2 million due to hedging losses in the prior year period partially offset by a $0.9 million decrease due to lower natural gas sales due to lower sales volumes for the three months ended September 30, 2002 as compared to the same period in 2001.

Other operating expenses for the three months ended September 30, 2002 decreased approximately $2.1 million or 36.2 percent as compared to the same period in 2001. Other operating expenses include operating and maintenance expenses, depreciation and amortization expense and taxes other than income. Operating and maintenance expenses decreased approximately $0.3 million or 93.3 percent for the three months ended September 30, 2002 as compared to the same period in 2001. This decrease was due to a $0.3 million decrease in exploration expenses as the exploration and production assets have been or are in the process of being sold.

Depreciation and amortization expense decreased approximately $1.8 million or 72.1 percent for the three months ended September 30, 2002 as compared to the same period in 2001 due to ceasing depreciation on the assets which have been or are in the process of being sold.

Other expense increased approximately $2.2 million for the three months ended September 30, 2002 as compared to the same period in 2001 primarily due to a $2.3 million loss on the sale of the exploration and production assets during the three months ended September 30, 2002.

Nine months ended September 30, 2002 compared to Nine months ended September 30, 2001

Gross margin for the nine months ended September 30, 2002 decreased approximately $10.1 million or 34.2 percent as compared to the same period in 2001. The decrease was primarily attributable to an decrease of approximately $9.2 million due to lower natural gas sales due to lower prices and sales volumes for the nine months ended September 30, 2002 as compared to the same period in 2001, a $0.6 million decrease due to hedging losses in the prior year period, a $0.2 million decrease related to lower prices and increased volumes related to NuStar and a $0.1 million decrease in crude oil sales.

Other operating expenses for the nine months ended September 30, 2002 decreased approximately $3.3 million or 20.0 percent as compared to the same period in 2001. Other operating expenses include operating and maintenance expenses, depreciation and amortization expense and taxes other than income. Operating and maintenance expenses decreased approximately $1.5 million or 14.9 percent for the nine months ended September 30, 2002 as compared to the same period in 2001. This decrease was due to a $0.9 million decrease in exploration expenses and a $1.4 million decrease in production costs as the exploration and production assets have been or are in the process of being sold partially offset by an $0.8 million increase in miscellaneous operating expenses related to NuStar for the nine months ended September 30, 2002 as compared to the same period in 2001.

Depreciation and amortization expense decreased approximately $1.8 million or 32.1 percent for the nine months ended September 30, 2002 as compared to the same period in 2001 due to ceasing depreciation on the assets which have been or are in the process of being sold.

Other expense increased approximately $1.9 million for the nine months ended September 30, 2002 as compared to the same period in 2001 primarily due to a $2.3 million loss on the sale of the exploration and production assets during the nine months ended September 30, 2002 partially offset by a $0.4 million decrease in minority interest expense for the nine months ended September 30, 2002 as compared to the same period in 2001.

Liquidity and Capital Requirements

As discussed previously, in January 2002, a significant ice storm hit OG&E's service territory and inflicted major damage to the transmission and distribution infrastructure with total expenditures of approximately $92.0 million. OG&E requested the OCC to include in its existing rate case relief from the approximately $92.0 million in damages caused by the ice storm.

On October 11, 2002, OG&E, the OCC Staff, the Oklahoma Attorney General and other interested parties agreed to a settlement of OG&E's rate case. The settlement stipulates recovery by OG&E, through rate base, of the capital expenditures associated with the January 2002 ice storm and 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 off-system sales. In addition, the settlement stipulates that OG&E intends to take steps to purchase electric generating

facilities of not less than 400 Megawatts ("MW's") to be integrated into OG&E's generation system. See "Regulation and Rates-Recent Regulatory Matters" for a further discussion.

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 capital requirements are primarily related to maturing debt, capital and operating lease obligations, unconditional purchase obligations and hedging activities. The Company generally meets its cash needs through a combination of internally generated funds, short-term borrowings and permanent financings. Capital expenditures for the nine months ended September 30, 2002 were $188.8 million and were financed with internally generated funds and short-term borrowings. As discussed previously, Enogex retired $83.0 million of long-term debt that matured during the three months ended September 30, 2002 with cash on hand.

Management expects that internally generated funds will be adequate during the remainder of 2002 to meet anticipated construction expenditures and maturities of long-term debt. Short-term borrowings will continue to be used to meet temporary cash requirements. OG&E has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time. The Company has in place lines of credit in the aggregate for up to $410 million, with $15 million expiring on April 6, 2003, $100 million expiring on June 26, 2003, $195 million expiring on January 9, 2003 and $100 million expiring on January 15, 2004. Short-term borrowings will consist of a combination of bank borrowings and commercial paper. The Company's ability to access the commercial paper market could be adversely impacted by a commercial paper ratings downgrade. The line of credit contains ratings triggers that require annual fees and borrowing rates to increase if the Company suffers an adverse ratings impact. The impact of a downgrade 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 ratings triggers. Also, contributing to the liquidity of the Company, have been numerous asset sales by Enogex. Completed sales and anticipated sales are expected to generate proceeds of approximately $66.8 million during 2002. The sales proceeds have been and will be used to reduce debt at Enogex. During 2003, the Company expects to have strong cash flows from operations to meet normal operating needs, payment of dividends and debt service.

Like any business, the Company is subject to numerous contingencies, many of which are beyond its control. For a discussion of significant contingencies that could affect the Company, reference is made to Notes 8 and 11 of the Notes to Condensed Consolidated Financial Statements and to Part II, Item 1 - "Legal Proceedings" of this Form 10-Q, Part II, Item 1 - "Legal Proceedings" in the Company's Form 10-Q for the quarters ended March 31, 2002 and June 30, 2002; and to Part II, Item 7 - "Management's Discussion and Analysis of Financial Condition and Results of Operations" and Notes 10 and 11 of Notes to the Consolidated Financial Statements in the Company's Form 10-K for the year ended December 31, 2001.

Critical Accounting Policies and Estimates

The Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements included in this Form 10-Q and in the Company's Form 10-K for the year ended December 31, 2001 contain information that is pertinent to Management's Discussion and Analysis. In preparing these 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. These assumptions and estimates could have a material effect on the Company's Consolidated Financial Statements. However, the Company has taken 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, contingency reserves, unbilled revenue for the electric utility, the allowance for uncollectible accounts receivable, the valuation of energy trading purchases and sales contracts and gas storage inventory.

Consolidated (including OG&E and Enogex)

Pension and other postretirement plan expenses and liabilities are determined on an actuarial basis and are affected by the market value of plan assets, estimates of the expected return on plan assets and assumed discount rates. Actual changes in the fair market value of plan assets and differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension expense ultimately recognized. For a discussion of the pension plan rate assumptions, reference is made to Note 8 of the Notes to Consolidated Financial Statements in the Company's Form 10-K for the year ended December 31, 2001.

The assumed return on plan assets is based on management's expectation of the long-term return on plan assets portfolio. The discount rate used to compute the present value of plan liabilities is based generally on rates of high grade corporate bonds with maturities similar to the average period over which benefits will be paid.

From time to time, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to claims made by third parties 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 financial statements.

OG&E

OG&E reads its customers' meters and sends its bills throughout each month. As a result, there is a significant amount of customers' electricity consumption that has not been billed at the

end of each month. This unbilled revenue is estimated by adding the amount of electric power generated and purchased less off-system sales and estimated line losses, which results in net kilowatt-hours available for sale for the current period. From this number, the amount of billed kilowatt-hours are deducted to arrive at an estimate of unbilled kilowatt-hours for the period. These unbilled kilowatt-hours are then multiplied by an estimate of the average price to be paid by customers to arrive at unbilled revenue. The estimates that management uses in this calculation could vary from the actual price to be paid by customers, but when consistently applied from period to period, this method should not result in any material differences.

The allowance for uncollectible accounts receivable is calculated by multiplying the last six months of electric revenue by the provision rate. The provision rate is based on a 12 month historical average of actual balances written off. To the extent that historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized.

Enogex

Energy trading contracts are entered into by OGE Energy Resources Inc. ("OERI"), the trading and marketing subsidiary of Enogex. All trading activities of OERI are accounted for on a mark-to-market basis. Corporate risk management and credit committees charged with enforcing the trading and credit policies, which include strict guidance on counterparties, procedures, credit and trading limits, monitor these activities. Trading activities include the trading and marketing of natural gas, electricity, crude oil and crude products. The vast majority of positions expire within two years, which is when the cash aspect of the transactions will be realized. In nearly all cases, independent market prices are obtained and compared to the values used for the mark-to-market valuation, and an oversight group outside of the trading and marketing organization monitors all modeling methodologies and assumptions. As a result of this mark-to-market valuation method, the value of the energy trading contracts may change significantly in the future as the market price for the commodity changes, but the value is still subject to the risk loss limitations provided under the Company's trading policies. At September 30, 2002, unrealized mark-to-market losses were $16.9 million, which included $17.1 million based on independent market prices. In October 2002, the Emerging Issues Task Force ("EITF") reached a consensus to rescind EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities", as amended. See Note 2 to the Condensed Consolidated Financial Statements for a further discussion.

Gas storage inventory used in Enogex's trading activities is marked to market utilizing a gas index that in management's opinion approximates the current market value of natural gas in that region as of the Balance Sheet date. However, the actual market value could materially change in the future due to changes in market conditions such as weather or supply and demand. See Note 2 to the Condensed Consolidated Financial Statements for a further discussion.

Regulation and Rates

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.

The order of the OCC authorizing OG&E to reorganize into a subsidiary of the Company contains certain provisions which, among other things, ensure the OCC access to the books and records of the Company and its affiliates relating to transactions with OG&E; require the Company to employ accounting and other procedures and controls to protect against subsidization of non-utility activities by OG&E's customers; and prohibit the Company from pledging OG&E assets or income for affiliate transactions.

Recent Regulatory Matters

In September 2001, the director of the OCC public utility division filed an application with the OCC to review the rates of OG&E. In the filing, the OCC Staff requested that OG&E submit information for a test year ending September 30, 2001. On December 14, 2001, OG&E, citing the need for investment in security and system reliability, filed a notice with the OCC of its intent to seek an increase in OG&E's electric rates. On January 28, 2002, OG&E filed testimony with the OCC supporting OG&E's request for a $22.0 million annual rate increase with $10.3 million related to investments for security and $11.7 million attributable to investments in increased system reliability and increased utility costs. Over the past 16 years, OG&E has had several rate reductions that have totaled more than $142.0 million annually.

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. Initially, approximately $10.3 million of the January 28, 2002 rate increase requested by OG&E was to invest in increased security. As described below, OG&E subsequently withdrew its request for the $10.3 million related to security.

The additional $11.7 million of the original $22.0 million request was for investment in increased system reliability and for increased utility costs. OG&E had added new generation capacity to meet growing customer demand and had determined that it needed to increase expenditures for distribution system reliability following a series of record-breaking storms, including a 1995 windstorm in the Oklahoma City area affecting 175,000 customers, 1999 tornadoes affecting about 150,000 customers and disrupting service at a power plant, July 2000 thunderstorms affecting 110,000 customers, a Christmas 2000 ice storm affecting 140,000 customers, Memorial Day 2001 storms leaving 143,000 customers without power and at least two other storms affecting at least 100,000 customers each.

Additionally, OG&E had experienced an overall increase in operating expenses. As part of it's filing, OG&E sought approval to offer several new rate program choices to customers. One such pilot program involves flat billing. This option would set a customer's bill at a fixed dollar amount and would not change throughout the year regardless of the amount of power consumed. The bill amount would then be adjusted in the following year based on the previous year's usage and other factors. Another proposed rate program, a Green Power option, would involve OG&E contracting with wind generators to purchase a quantity of wind-generated power, then offering that power to customers. The rate would reflect the higher cost of wind-generated power.

As discussed previously, on January 30, 2002, a significant ice storm hit OG&E's service territory and inflicted major damage to the transmission and distribution infrastructure with total expenditures of approximately $92.0 million. On April 8, 2002, OG&E announced it would withdraw the $10.3 million increased security portion of its January request. Simultaneously with that announcement, OG&E filed a Joint Application with the Staff of the OCC for separate consideration of costs related to increased security requirements. Thereafter, on August 15, 2002, OG&E filed a report outlining proposed expenditures and related actions for security enhancement. OG&E is working with the OCC Staff under this separate filing to determine the appropriate dollar amount for security upgrades and recovery mechanisms. The OCC Staff has indicated its intent to retain a security expert to review the report filed by OG&E.

On July 1, 2002 OG&E filed direct testimony in support of recovery for the approximately $92.0 million in damages caused by the January 2002 ice storm. OG&E requested a $14.5 million annual increase in revenue requirement. The request included recovery of, and return on, $86.6 million of capital expenditures related to the ice storm and recovery, over three years, of $5.4 million of deferred operating costs. Recovery of costs associated with the January 2002 ice storm is included in the Joint Stipulation and Settlement Agreement discussed below.

On October 11, 2002, OG&E, the OCC Staff, the Oklahoma Attorney General and other interested parties agreed to a settlement (the "Settlement Agreement") of OG&E's rate case. The administrative law judge subsequently recommended approval of the Settlement Agreement. 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 begins with the first regular billing cycle occurring 41 days after the issuance of the OCC order approving the Settlement Agreement; (ii) recovery by OG&E, through rate base, of the capital expenditures associated with the January 2002 ice storm; (iii) 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 off-system sales; (iv) OG&E to acquire electric generating capacity ("New Generation") of not less than 400 MW's to be integrated into OG&E's generation system. The Settlement Agreement remains subject to the review and approval of the three commissioners of the OCC. The OCC will meet in November 2002 to review the Settlement Agreement. Key portions of the Settlement Agreement are described below.

I. Rate Reduction to Oklahoma Customers

The Settlement Agreement stipulates that OG&E will file tariffs, designed to reflect an annual reduction of $25.0 million in OG&E's Oklahoma jurisdictional operating revenue. The $25.0 million annual reduction is to begin with the first regular billing cycle which occurs 41 days after the issuance of the OCC order approving the Settlement Agreement.

II. Recovery of Storm Damages

The Settlement Agreement stipulates that OG&E will be allowed to earn a return, through base rates, on the capital expenditures related to the January 2002 ice storm. The Settlement Agreement also stipulates that OG&E will be allowed recovery of $5.4 million of deferred operating costs related to the January 2002 ice storm. The recovery of the $5.4 million in operating costs will be recovered over a three year period through OG&E's rider for off-system sales. Currently, OG&E has a 50/50 sharing mechanism in Oklahoma for any off-system sales. The Settlement Agreement, when it becomes effective, will provide 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.

III. New Generation

In addition to the $25.0 million annual rate reduction to OG&E's Oklahoma customers, OG&E intends to take steps to purchase electric generating facilities of not less than 400 MW's to be integrated into OG&E's generation system. OG&E will have the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the acquisition and initial operation of the New Generation, consisting of the non-fuel operation and maintenance expenses, depreciation, cost of debt associated with the capital investment and ad valorem taxes related to the New Generation. In addition to the accrual of the regulatory asset, OG&E must file an application with the OCC for the inclusion of the New Generation into OG&E's rate base, as part of a general rate review, no later than 12 months following the acquisition and initial operation of the New Generation. Upon approval by the OCC of the application, all prudently incurred costs accrued through the regulatory asset within the 12 month period will be included in OG&E's prospective cost of service. The period for recovery of the regulatory asset will be determined by the OCC. OG&E expects this New Generation will provide savings, over a three year period, in excess of $75.0 million to OG&E's Oklahoma customers. These savings will be derived from: (i) the avoidance of purchase power contracts otherwise needed; (ii) replacing an above market cogeneration contract when it can be terminated at the end of August 2004; and (iii) fuel savings associated with operating efficiencies of a new plant. These savings, while providing real savings to OG&E's Oklahoma customers, should have no effect on the profitability of OG&E.

As indicated above, OG&E's decision with respect to the purchase of the New Generation will be subject to a review by the OCC as a part of a general rate case for the purpose of determining the level of just and reasonable costs associated with the New Generation to be included in OG&E's rate base. The OCC's review is expected to include, but not be limited to, an analysis and review of the alternatives to purchasing the New Generation, the amount paid for such New Generation and the level of capacity purchases. OG&E will provide monthly reports, for a period of 36 months, to the OCC Staff, documenting and providing proof of savings experienced by OG&E's customers. In determining the 36 month savings OG&E will be required to include in its reports: (1) the avoidance of purchased capacity otherwise required to meet Southwest Power Pool capacity margin requirements; (2) credits to customers accruing by virtue of cogeneration contract terminations; and (3) the fuel savings associated with the operating efficiencies of OG&E's generating facilities including the New Generation compared to the fuel efficiencies of OG&E's generation facilities in operation during the test year related to the Settlement Agreement. The operating costs associated with the New Generation will be deducted from the sum of the three items discussed above to determine the ultimate amount of savings. In determining the 36 month savings, OG&E will not include savings to its customers which occur as the result of scheduled reduction in ongoing cogeneration contract payments. 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 have an obligation to credit its customers any unrealized savings below $75.0 million as determined at the end of the 36 month period, which shall be no later than December 31, 2006.

In the event OG&E does not acquire the New Generation by December 31, 2003, OG&E will be required to 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. However, if OG&E purchases the New Generation subsequent to January 2004, the credit to Oklahoma customers will terminate in the first month that the New Generation begins initial operations and any credited amount to Oklahoma customers will be included in the determination of the $75.0 million targeted savings.

IV. Rate Design

As part of the Settlement Agreement OG&E has agreed to withdraw its request for a Coal Utilization Performance Rider ("CUP Rider") and a Transmission Investment Recovery Rider ("TIR Rider"). OG&E agreed not to seek implementation of a CUP Rider or a TIR Rider or other similar riders in OG&E's next general rate proceeding or during the 36 month benefit period of the New Generation. However, in the event federal regulation of the interstate transmission grid results in a new rate design which increases costs to OG&E's Oklahoma customers, OG&E will not be precluded from requesting a TIR Rider. Reference is made to "Rate Activities and Proposals" in the Company's Form 10-K for the year ended December 31, 2001.

V. Gas Transportation Service

OG&E's current gas transportation service contract with its affiliate Enogex for OG&E's current gas-fired generation facilities has a primary term ending in April 2004. Reference is

made to Note 11 of Notes to the Consolidated Financial Statements in the Company's Form 10-K for the year ended December 31, 2001. As part of the Settlement Agreement, OG&E agreed to consider competitive bidding as an option when analyzing the extension or renewal of OG&E's gas transportation service contract with Enogex prior to April 2004. OG&E further agreed to consider competitive bidding as an option for all natural gas transportation services and gas supply acquisition practices to all new generation facilities built, purchased or placed into service after October 9, 2002. If OG&E chooses not to utilize competitive bidding to obtain all natural gas transportation services to its current generation facilities, after April 2004, or to any new generation facilities, OG&E must then provide the OCC Staff and the office of the Oklahoma Attorney General all data and information upon which the decision was based.

Other Regulatory Actions

As previously reported, certain aspects of OG&E's electric rates recently have been addressed by the OCC. In March 2000, the OCC approved, and OG&E implemented, the APC Rider reflecting the completion of the recovery of the amortization premium paid by OG&E when it acquired Enogex in 1986. The effect of the APC Rider was to remove $10.7 million annually from the amount being recovered by OG&E from its Oklahoma customers in current rates. In June 2000, the OCC approved modifications to OG&E's GEP Rider. The GEP Rider was established initially in 1997 in connection with OG&E's last general rate review and was intended to encourage OG&E to lower its fuel costs. The GEP Rider expired in June 2002. In June 2001, the OCC approved a stipulation (the "Stipulation") to the competitive bid process of OG&E's gas transportation service. The Stipulation directed OG&E to reduce its rates to its Oklahoma retail customers by approximately $2.7 million per year through the implementation of a GTAC Rider. The GTAC Rider is a credit for gas transportation cost recovery and is applicable to and becomes part of each Oklahoma retail rate schedule to which OG&E's Fuel Cost Adjustment rider applies. The GTAC Rider became effective with the first billing cycle of July 2001. For a further discussion of the APC Rider, GEP Rider and GTAC Rider reference is made to Note 11 of Notes to the Consolidated Financial Statements in the Company's Form 10-K for the year ended December 31, 2001.

The Settlement Agreement, when it becomes effective, provides for the termination of the APC Rider and the GTAC Rider.

FERC Section 311 Rate Case

In December 2001, Enogex made its filing at FERC under Section 311 of the Natural Gas Policy Act to establish (for the combined Enogex-Transok system) rates and a treating fee and to address various other issues, effective January 1, 2002. The FERC Staff, Enogex and the active intervening parties have initiated settlement discussions. Enogex has negotiated a settlement of all issues (in principle) with five parties and continues to negotiate with one other party. The outstanding, unresolved issues with the single party are relatively narrow and Enogex is hopeful that the parties will be able to resolve these issues in the near future in order to file and receive FERC acceptance of a complete settlement of this case by year-end 2002.

State Restructuring Initiatives

<u>Oklahoma</u>: As previously reported, Oklahoma enacted in April 1997 the Electric Restructuring Act of 1997 (the "Act"), which was designed to provide for choice by retail customers of their electric supplier by July 1, 2002. In May 2001, the Oklahoma Legislature passed Senate Bill 440 ("SB 440"), which postponed the scheduled start date for customer choice from July 1, 2002 until at least 2003. In addition to postponing the date for customer choice, the SB 440 calls for a nine-member task force to further study the issues surrounding deregulation. The task force includes the Governor or his designee, the Oklahoma Attorney General, the OCC Chair and several legislative leaders, among others. The Company will continue to participate actively in the legislative process and expects to remain a competitive supplier of electricity. The Company cannot predict what, if any, legislation will be adopted at the next legislative session.

<u>Arkansas</u>: 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, like the Act, will significantly affect OG&E's future operations. OG&E's electric service area includes parts of western Arkansas, including Fort Smith, the second-largest metropolitan market in the state. The

Restructuring Law initially targeted customer choice of electricity providers by January 1, 2002. In February 2001, the Restructuring Law was amended to delay the start date of customer choice of electric providers in Arkansas until October 1, 2003, with the APSC having discretion to further delay implementation to October 1, 2005. The Restructuring Law also provides that utilities owning or controlling transmission assets must transfer control of such transmission assets to an independent system operator, independent transmission company or regional transmission group, if any such organization has been approved by the FERC. OG&E filed preliminary business separation plans with the APSC on August 8, 2000. The APSC has established a timetable to establish rules implementing the Restructuring Law.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

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 committee has been established to review these risks on a regular basis. The Company is exposed to market risk, including changes in certain commodity prices and interest rates.

To manage the volatility relating to these exposures, the Company enters into various derivative transactions pursuant to the Company's policies on hedging practices. Derivative 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 may utilize 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 adopted Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities," on January 1, 2001 and accounted for its adoption by recording a cumulative effect transition adjustment debit to Accumulated Other Comprehensive Income of approximately $26.9 million ($16.5 million net of tax). This unrealized loss was related to the derivative fair value of qualifying cash flow hedges as of the date of adoption and was later reclassified to earnings when the related hedged transactions were reflected in income. As of December 31, 2001, this amount had been reclassified to earnings. However, the initial unrealized loss was offset by a subsequent gain on these qualifying cash flow hedges of approximately $21.4 million ($13.1 million net of tax). As of December 31, 2001, the Company also recorded a gain, which is included in Operating Revenues, related to the ineffective portion of hedge derivatives, for production hedges, of $4.7 million ($3.0 million net of tax) resulting in an overall loss of approximately $0.8 million ($0.4 million net of tax).

During 2001, the Company entered into two separate interest rate swap agreements: (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 an interest rate swap agreement, effective July 15, 2001, to convert $200.0 million of 8.125 percent fixed rate

debt due January 15, 2010, to a variable rate based on the three month LIBOR. On March 1, 2002, Enogex monetized its interest rate swap agreement and received cash of $4.2 million, which will be amortized over the life of the related debt.

On March 4, 2002, Enogex entered into a new interest rate swap agreement to convert $200.0 million of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the three month LIBOR. On July 2, 2002, Enogex monetized its interest rate swap agreement and received cash of $6.6 million, of which $3.2 million was recorded against interest receivable and the remaining amount of $3.4 million will be amortized over the remaining life of the related debt.

On August 7, 2002, Enogex entered into a new interest rate swap agreement to convert $100.0 million of 8.125 percent fixed rate debt due, January 15, 2010, to a variable rate based on the six month LIBOR.

On October 24, 2002, Enogex entered into a new interest rate swap agreement to convert $100.0 million of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the six month LIBOR.

These interest rate swaps qualified as fair value hedges under SFAS No. 133 and meet all of the requirements for a determination that there was no ineffective portion as allowed by the shortcut method under SFAS No. 133. The objective of these interest rate swaps was to achieve a lower cost of debt and raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standard.

Enogex retired $83.0 million of long-term debt that matured during the three months ended September 30, 2002. This debt consisted of $3.0 million principal amount of 7.02 percent medium-term notes due August 7, 2002, $35.0 million principal amount of 7.04 percent medium-term notes due August 7, 2002, $25.0 million principal amount of 7.05 percent medium-term notes due August

7, 2002, $1.0 million principal amount of 7.33 percent medium-term notes due August 26, 2002, $5.0 million principal amount of 7.35 percent medium-term notes due August 26, 2002 and $14.0 million principal amount of 7.32 percent medium-term notes due August 26, 2002.

The fair value of long-term debt is estimated based on quoted market prices and management's estimate of current rates available for similar issues. The following table shows the Company's long-term debt maturities and the weighted-average interest rates by maturity date.

(Dollars in millions)	2003(A)	2004	2005	Thereafter	Total	Fair Value at September 30, 2002
Fixed rate debt						
Principal amount...	$ 12.0	$ 54.0	$ 146.3	$ 860.8	$1,073.1	$1,115.1
Weighted-average interest rate....	7.62%	7.22%	7.07%	7.48%	7.41%	---
Variable rate debt						
Principal amount...	---	---	---	$ 463.1	$ 463.1	$ 463.1
Weighted-average interest rate....	---	---	---	4.07%	4.07%	---

(A) Does not include long-term debt due within one year.

Commodity Price Risk

The market risk inherent in the Company's market risk sensitive instruments and positions are the potential loss in value arising from adverse changes in the Company's commodity prices.

The prices of natural gas, natural gas liquids and electricity are subject to fluctuations resulting from changes in supply and demand. To partially reduce commodity price risk caused by these market fluctuations, the Company may hedge, through the utilization of derivatives, a portion of the Company's supply and related purchase and sale contracts, as well as any anticipated transactions (purchases and sales). Because the commodities covered by these derivatives are substantially the same commodities that the Company buys and sells in the physical market, no special studies other than monitoring the degree of correlation between the derivative and cash markets are deemed necessary.

A sensitivity analysis has been prepared to estimate the commodity price risk exposure to the market risk of the Company's natural gas, natural gas liquids and electricity commodity positions. The Company's daily net commodity position consists of natural gas inventories, purchased electric capacity, commodity purchase and sales contracts and derivative financial and commodity instruments. The fair value of such position is a summation of the fair values calculated for each commodity by valuing each net position at quoted market prices. Market risk is estimated as the potential loss in fair value resulting from a hypothetical ten percent adverse change in such prices over the next 12 months. The results of this analysis, which may differ from actual results, are as follows at September 30, 2002:

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

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 Securities and Exchange Commission rules and forms. within the 90-day period prior to the filing of this report, an evaluation was 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. Based on that evaluation, the CEO and CFO have concluded that the Company's disclosure controls and procedures are effective.

Subsequent to the date of their evaluation, there have been no significant changes in the Company's internal controls or in other factors that could significantly affect these controls.

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Reference is made to Part I, Item 1 – Notes 8 and 11 to Condensed Consolidated Financial Statements in this Form 10-Q; Item 3 of the Company's Form 10-K for the year ended December 31, 2001 and to Part II, Item 1 of the Company's Form 10-Q for the quarters ended March 31, 2002 and June 30, 2002 for a description of certain legal proceedings presently pending. Except as set forth below, 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.

As reported in Part II, Item 1 of the Company's Form 10-Q for the quarter ended June 30, 2002, in early 2002, a dispute arose between Enogex and Dynegy Marketing and Trade relating to the termination of a storage agreement. On September 25, 2002, the parties settled the dispute and the Court entered its Order dismissing the pending declaratory judgment action on September 26, 2002.

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits

Exhibit No.	Description
99.01	Certification Pursuant to 18 U.S.C. Section 1350 As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.02	Copy of Settlement Agreement with the Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's rate case.

(b) Reports on Form 8-K

The Company filed a Current Report on Form 8-K on August 5, 2002 to report the resignation of the President and Chief Executive Officer of the Company's Enogex subsidiary.

The Company filed a Current Report on Form 8-K on August 14, 2002 to report the certification of the Company's financial statements for the quarterly period ended June 30, 2002 by the Company's Chief Executive Officer and Chief Financial Officer pursuant to Order 4-460 and 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 14, 2002

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 quarterly 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 quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures 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 quarterly report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant's other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant's ability to record, process, summarize and report financial data and have identified for the registrant's auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: November 14, 2002

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

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 quarterly 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 quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly report;

4. The registrant's other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:

a) designed such disclosure controls and procedures 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 quarterly report is being prepared;

b) evaluated the effectiveness of the registrant's disclosure controls and procedures as of a date within 90 days prior to the filing date of this quarterly report (the "Evaluation Date"); and

c) presented in this quarterly report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;

5. The registrant’s other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant’s auditors and the audit committee of registrant’s board of directors (or persons performing the equivalent function):

a) all significant deficiencies in the design or operation of internal controls which could adversely affect the registrant’s ability to record, process, summarize and report financial data and have identified for the registrant’s auditors any material weaknesses in internal controls; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal controls; and

6. The registrant's other certifying officers and I have indicated in this quarterly report whether or not there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: November 14, 2002

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

Exhibit 99.01

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, 2002, 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 14, 2002

/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

Exhibit 99.02

BEFORE THE CORPORATION COMMISSION
OF THE STATE OF OKLAHOMA

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APPLICATION OF ERNEST G. JOHNSON,     )
DIRECTOR OF THE PUBLIC UTILITY        )
DIVISION, OKLAHOMA CORPORATION        )
COMMISSION TO REVIEW THE RATES,       )
CHARGES, SERVICES, AND SERVICE TERMS )      CAUSE NO. PUD 200100455
```

OF OKLAHOMA GAS AND ELECTRIC)
COMPANY AND ALL AFFILIATED)
COMPANIES AND ANY AFFILIATE OR)
NONAFFILIATE TRANSACTION RELEVANT)
TO SUCH INQUIRY)

JOINT STIPULATION AND SETTLEMENT
AGREEMENT

October 11, 2002

BEFORE THE CORPORATION COMMISSION
OF THE STATE OF OKLAHOMA

APPLICATION OF ERNEST G. JOHNSON,) DIRECTOR OF THE PUBLIC UTILITY) DIVISION, OKLAHOMA CORPORATION) COMMISSION TO REVIEW THE RATES,) CHARGES, SERVICES, AND SERVICE TERMS) OF OKLAHOMA GAS AND ELECTRIC) COMPANY AND ALL AFFILIATED) COMPANIES AND ANY AFFILIATE OR) NONAFFILIATE TRANSACTION RELEVANT) TO SUCH INQUIRY)	CAUSE NO. PUD 200100455

JOINT STIPULATION AND SETTLEMENT
AGREEMENT

COME NOW the undersigned parties to the above entitled cause and pursuant to 17 O.S.§282 present the following Joint Stipulation and Settlement Agreement ("Joint Stipulation") for the Commission's review and approval as their compromise and settlement of all issues in this proceeding between the parties to this Joint Stipulation ("Stipulating Parties"). The Stipulating Parties represent to the Commission that this Joint Stipulation represents a fair, just and reasonable settlement of these issues, that the terms and conditions of the Joint Stipulation are in the public interest, and the Stipulating Parties urge the Commission to issue an Order in this Cause adopting and approving this Joint Stipulation.

It is hereby stipulated and agreed by and between the Stipulating Parties as follows:

Terms of the Joint Stipulation and Settlement Agreement

This Joint Stipulation represents a comprehensive total settlement benefit package of not less than $50 million consisting of a rate reduction of $25 million to become effective with the first regular billing cycle which occurs 41 days after the Commission order approving this Joint Stipulation is issued; and phased-in customer savings, as specified below, of at least an additional $25 million on an annualized basis for the 36-month period, beginning with the initial operation of new generation facilities or no later than January 1, 2004, ("the 36-month benefit period"), as specified below.

1. **Rate Reduction.** The Oklahoma Corporation Commission Staff ("Staff") initiated this proceeding on September 7, 2001, to investigate the reasonableness of Oklahoma Gas and Electric Company's ("OG&E" or the "Company") current rates, charges, services and terms and conditions of service to the Company's Oklahoma retail

customers. As a result of that review, the Stipulating Parties represent and agree that OG&E shall file tariffs designed to produce Oklahoma jurisdictional operating revenues of $1,271,687,611 based upon the test year billing units reflected in Section M of the Company's Application Package filed in this proceeding on January 28, 2002, as adjusted by Staff for weather normalization. The Company shall recover its Oklahoma jurisdictional operating revenue through tariffs reflecting the rate design set forth in Paragraph 4 of this Joint Stipulation, and said tariffs shall reflect an annual reduction from current base rate tariffs in the amount of $25 million beginning with the first regular billing cycle which occurs 41 days after the Commission order approving this Joint Stipulation is issued. Calculation of the rate reduction incorporated in this Joint Stipulation is set forth on Exhibit "A" to this Joint Stipulation and Settlement Agreement.

2. **Phased-In Customer Savings.** In addition to the immediate rate reduction set forth in Paragraph 1 of this Joint Stipulation, the Stipulating Parties understand that OG&E intends to take steps to purchase electric generating facilities of not less than 400 Megawatts ("New Generation") to be integrated into the Company's generation system. The Company's decision with respect to the purchase of the New Generation shall be subject to a prudency review by the Commission for the purpose of determining the level of just and reasonable costs associated with the New Generation to be included in rate base and the remaining Stipulating Parties make no commitment with respect to acceptance or rejection of the Company's decision to acquire the New Generation. The Commission's prudency review shall include, but not be limited to, an analysis and review of the alternatives to purchasing the New Generation, the amount paid for such Generation and the level of capacity purchased. The Company agrees that as a part of this provision of the Joint Stipulation, OG&E shall inform the parties to this Cause of the status of implementation of this provision of the Joint Stipulation.

Subsequent to the inclusion of the New Generation in OG&E's generation assets, OG&E shall provide monthly reports to the Staff of the Commission, reflecting the savings experienced by the Company's Oklahoma jurisdictional retail customers for a period of 36 months. The Company shall make available to the Staff and AG all calculations and work papers supporting such savings. Any request to review said calculations and work papers by any interested party shall be subject to compliance with Oklahoma law and the Orders of this Commission.

During said 36-month period, OG&E shall document and provide proof of savings to said customers of at least $75 million. In determining the 36-month savings, the Company shall include: (1) the avoidance of purchased capacity otherwise required to meet Southwest Power Pool capacity margin requirements; (2) credits to customers accruing by virtue of cogeneration contract terminations; and (3) the fuel savings associated with the operating efficiencies of the Company's generating facilities including the New Generation compared to the fuel efficiencies of OG&E's generation facilities in operation during the test year in this proceeding. From the

sum of these amounts shall be deducted the operating costs associated with the New Generation, as reflected in Footnote 4 of the Phased-in Customer Savings Calculation format reflected in Exhibit "B". Exhibit "B" to this Joint Stipulation reflects the formula for the calculation of said savings and the assumptions related to the variables in the formula. In the event that OG&E is unable to demonstrate at least $75 million in savings to its Oklahoma jurisdictional customers during the 36-month period subsequent to the acquisition and initial operation of the New Generation, the Company shall have an obligation to credit to said customers any unrealized savings as determined at the end of said period: which shall be no later than December 31, 2006. In determining the 36-month savings, the Company shall not include savings to customers which occur as the result of scheduled reductions in cogeneration contract payments. It is the intention of the parties that to the extent any credit is due to customers at the end of the 36-month period because demonstrated savings are less than $75 million, customers on the OG&E system during any portion of the 36-month period shall be entitled to receive an allocation of such credit as determined by the Commission. In the event that the Company does not acquire the New Generation by December 31, 2003, the Company shall credit its Oklahoma jurisdictional customers the sum of $25 million per year, beginning January 1, 2004 and continuing through December 31, 2006. Said $25 million per year shall be pro-rated on a monthly basis. If OG&E purchases New Generation subsequent to January 2004, the credit terminates the first month that the New Generation begins initial operations. The credited amount to customers will be included in the determination of the $75 million targeted savings. The Phased-in Customer Savings Calculation will be effective for the remainder of the 36-month benefit period. The Commission shall conduct a hearing to determine the level of savings and any necessary credits.

3. **Regulatory Asset and New Rate Proceeding.** For a period not to exceed twelve months subsequent to the acquisition and initial operation of the generation facilities described in Paragraph 2 of this Joint Stipulation, OG&E shall have the right to accrue a Regulatory Asset which shall consist of the non-fuel operation and maintenance expenses, depreciation, debt cost associated with the capital investment, and ad valorem taxes related to the New Generation. In addition to the accrual of said Regulatory Asset, the Company agrees that it shall file an Application with the Commission pursuant to OAC 165:70, for the inclusion of New Generation in OG&E’s rate base, as part of a general rate review, no later than 12 months following the acquisition and initial operation of New Generation. After the Commission’s review and order regarding said Application, all prudently incurred costs accrued through the Regulatory Asset within the 12 month period shall be included in the Company’s prospective cost of service. The period for recovery of said Regulatory Asset shall be determined by the Commission at that time. The Company’s rates will be re-established to reflect recovery of the regulatory asset in rates. Recovery in rates of the regulatory asset will be subject to the policy and procedures of the Commission in effect at that time.

4. **Rate Design.**

   a. The Company shall design rates for its major classes of service and structure the resulting tariffs, which are attached hereto as Exhibit “C”, such that the classes shall receive the rate reduction described in Paragraph 1 of this Joint Stipulation. The spread of this rate reduction among the affected classes is reflected in Exhibit “D” to this Joint Stipulation.

   b. As a part of the consideration for this Joint Stipulation, OG&E has agreed to withdraw its request for a Coal Utilization Performance (“CUP”) Rider, and the Stipulating parties further agree not to seek implementation of a CUP Rider or other similar type riders in OG&E’s next general rate proceeding or during the 36-month benefit period.

   c. In addition, OG&E has agreed to withdraw its request for a Transmission Investment Recovery (“TIR”) Rider from this cause, and the Stipulating Parties agree not to seek implementation of a TIR Rider or other similar type riders in its next general rate proceeding or during the 36-month benefit period; provided, however, that in the event federal regulation of the interstate transmission grid results in a new rate design that increases costs to OG&E’s Oklahoma jurisdictional customers, OG&E shall not be precluded from requesting a TIR Rider.

   d. The Stipulating Parties further agree that the Company shall file a Rider for Cogeneration Credit (“CCR”) attached hereto as Exhibit “E”, as a part of its rate design tariffs to implement this Joint Stipulation, and said CCR shall be designed to return purchased capacity cost reductions and any fixed O&M cost reductions related to cogeneration contracts to OG&E’s customer classes on the same basis as those capacity costs were allocated to the Company’s customer classes on a historical basis. For the year 2005 and subsequent years in a general rate case or other proceeding, the Commission shall establish a new rider or change in base rates to return purchased capacity cost reductions and any change in O&M costs related to the cogeneration described herein based on demand allocators.

e. The Stipulating Parties agree that in addition to the Company's recovery of capital investment incurred to restore electric service from the January 2002 ice storm through base rates, OG&E shall recover its operation and maintenance expense incurred during that storm in the amount of $5,431,095 through the Company's Rider for Off-System Sales of Electricity. The Company shall design its Rider for Off-System Sales of Electricity to recover the first $1,810,366 in net profits from such sales per year for a three-year period; after the Company recovers this amount, said Rider for Off-System Sales of Electricity shall provide that the next $3,620,732 in net profits in each sales year shall be credited to OG&E's Oklahoma jurisdictional customers. Any net profits in excess of these amounts shall be

credited in each sales year to OG&E's Oklahoma jurisdictional customers with customers receiving 80% thereof, and the Company shall retain 20% of such net profits. If any amounts remain un-recovered of this $5.4 million at the end of the three years, then the Commission will authorize the recovery of the remaining costs. The Stipulating Parties further agree that no party to this Joint Stipulation will seek to change or modify the treatment of off-system sales as established herein in the next general rate case or during the three-year period. At the end of the three-year recovery period for operation and maintenance expenses related to the January 2002 ice storm, all net profits from off-system sales of electricity shall be credited 80% to Oklahoma jurisdictional customers, with the Company retaining 20% of such net profits.

f. The Company proposed to implement a Green Power Wind Rider (GPWR) as a program within Oklahoma, subject to Commission approval as a matter of policy. OG&E's proposal contemplated that for the program to be successful it could require a subsidy to encourage development of this renewable resource for energy in Oklahoma. The Stipulating Parties agree that this proposal should be applicable to all customers, except the Large Power and Light class customers that affirmatively elect not to participate; that the costs shall include up to $400,000 annually in educational advertising for the program; and that any subsidy or benefit resulting from implementation of the program shall be recovered from each of OG&E's customer classes. However, such costs shall not be recovered from those Large Power and Light class customers who have affirmatively elected to not participate in the GPWR. The Company should be directed to proceed with competitive bidding for the acquisition of a contract for 50 Megawatts of wind energy, and such contract shall be subject to the approval of the Commission. The final rate design for the GPWR and the recovery of any benefit or subsidy shall be subject to final determination at such time as OG&E submits a contract for wind energy to the Commission.

g. The Stipulating Parties agree that certain rate design modifications and proposals submitted by the Company were uncontested by any party to these proceedings. Attached to this Joint Stipulation and incorporated herein by reference as Exhibit "F" are tariffs and riders designed to implement OG&E's Guaranteed Flat Bill program, to modify OG&E's current Load Curtailment Program, establishing Qualification Rates, and implementing OG&E's PACE program, all of which should be approved by the Commission as a part of the Commission's Order to be issued in this proceeding.

h. The Stipulating Parties further agree that certain modifications to the Company's Fuel Cost Adjustment tariff are necessary to accommodate the changes required by this Joint Stipulation and a modification of the calculation of energy payments to AES Shady Point, Inc. to remove gas costs on a per unit basis from the Real Time Pricing incremental sales. The modification to OG&E's Fuel Cost Adjustment tariff is reflected in Exhibit "G" to this Joint Stipulation.

5. **Gas Transportation Service.** The current Gas Transportation Service Agreement pursuant to which Enogex Inc. provides natural gas transportation services to OG&E's current gas-fired generation facilities ("Current Generation Facilities") has a primary term ending April 30, 2004. The Stipulating Parties agree as follows:

   a. OG&E agrees to include competitive bidding as an option when analyzing the extension or renewal of the Enogex Gas Transportation Service Agreement prior to April 2004. Failure to utilize competitive bidding to obtain all natural gas transportation services and gas supply within its current supply acquisition practices, for the Current Generation Facilities after April 1, 2004, shall subject such OG&E contract(s) for the Current Generation Facilities to the requirements of paragraph (c.) below.

   b. OG&E further agrees to include competitive bidding as an option for all natural gas transportation services and gas supply within its current supply acquisition practices, to all new generation facilities built, purchased or placed into service after October 9, 2002 (collectively, “New Generation Facilities”). Failure to utilize competitive bidding to obtain all natural gas transportation services for the New Generation Facilities shall subject OG&E’s contract(s) for such services to the requirements of paragraph (c.) below.

   c. OG&E will advise the Staff and the other parties to this cause upon completion of all analyses of competitive bidding for the Current and New Generation Facilities. If OG&E chooses not to utilize competitive bidding to obtain all natural gas transportation services to the Current Generation Facilities (after April 1, 2004) and the New Generation Facilities, OG&E will provide Staff and the Attorney General’s office all data and information upon which those decisions were based, and the renewed or new contracts for natural gas transportation services or supply services shall be subject to a prudency review by the Commission.

   d. If a competitive bid package is issued pursuant to the competitive bidding option as referenced above, such competitive bid package shall not include the right of any party to match the lowest bid submitted by any other bidder, and each generation facility shall be bid separately for the services required. A competitive bidder may submit a bid for a combination of generation facilities in response to such competitive bid package, only if such bidder shall also submit or include a bid to serve those same plants individually.

6. **Discovery.** As between and among the Stipulating Parties, all pending requests for information or discovery and all motions pending before the Administrative Law Judge are hereby withdrawn.

7. **General Reservations.** The Stipulating Parties represent and agree that, except as specifically otherwise provided herein:

   a. This Joint Stipulation represents a negotiated settlement for the purpose of compromising and resolving all issues which were raised relating to this proceeding;

   b. Each of the undersigned counsel of record affirmatively represents to the Commission that he or she has fully advised their respective client(s) that the execution of this Joint Stipulation constitutes a resolution of all issues which were raised in this proceeding; that no promise, inducement or agreement not herein expressed has been made to any party to this Joint Stipulation; that this Joint Stipulation constitutes the entire agreement between and among the Stipulating Parties; and each of the undersigned counsel of record affirmatively represents that he or she has full authority to execute this Joint Stipulation on behalf of his or her client(s);

   c. None of the signatories hereto shall be prejudiced or bound by the terms of this Joint Stipulation in the event the Commission does not approve this Joint Stipulation; and

d. None of the signatories thereto shall be deemed to have approved or acquiesced in any ratemaking principle, capital structure, rate of return, recovery of costs, valuation method, cost of service determination, depreciation principle or method cost allocation method or rate design proposal underlying or allegedly underlying any of the rate schedules to be filed by OG&E upon approval by the Commission of this Joint Stipulation, and nothing contained herein shall constitute an admission by any party that any allegation or contention in these proceedings, or as to any of the foregoing matters, is true or valid and shall not in any respect constitute a determination by the Commission as to the merits of any allegations or contentions made in this rate proceeding.

e. The Stipulating Parties agree that the provisions of this Joint Stipulation are the result of extensive negotiations, and the terms and conditions of this Joint Stipulation are interdependent. The Stipulating Parties agree that settling the issues in this Joint Stipulation is in the public interest and, for that reason, they have entered into this Joint Stipulation to resolve among themselves the issues in this Joint Stipulation. This Joint Stipulation shall not constitute nor be cited as precedent nor deemed an admission by any Stipulating Party in any other proceeding except as necessary to enforce its terms before the Commission or any state court of competent jurisdiction. The Commission's decision, if it enters an order consistent with this Joint Stipulation, will be binding as to the matters decided regarding the issues described in this Joint Stipulation, but the decision will not be binding with respect to similar issues that might arise in other proceedings. A Stipulating Party's support of this Joint Stipulation may differ from its position or testimony in other causes. To the extent there is a difference,

the Stipulating Parties are not waiving their positions in other causes. Because this is a stipulated agreement, the Stipulating Parties are under no obligation to take the same position as set out in this Joint Stipulation in other dockets.

8. **Non-Severability.** The Stipulating Parties stipulate and agree that the agreements contained in this Joint Stipulation have resulted from negotiations among the Stipulating Parties and are interrelated and interdependent. The Stipulating Parties hereto specifically state and recognize that this Joint Stipulation represents a balancing of positions of each of the Stipulating Parties in consideration for the agreements and commitments made by the other Stipulating Parties in connection therewith. Therefore, in the event that the Commission does not approve and adopt the terms of this Joint Stipulation in total and without modification or condition (provided, however, that the affected party or parties may consent to such modification or condition), or in the event that the rate schedules proposed herein do not become effective for bills rendered in accordance with the provisions contained herein, this Joint Stipulation shall be void and of no force and effect, and no Stipulating Party shall be bound by the agreements or provisions contained herein. The Stipulating Parties agree that neither this Joint Stipulation nor any of the provisions hereof shall become effective unless and until the Commission shall have entered an Order approving all of the terms and provisions as agreed by the parties to this Joint Stipulation.

WHEREFORE, the Stipulating Parties hereby submit this Joint Stipulation and Settlement Agreement to the Commission as their negotiated settlement of this proceeding with respect to all issues which were raised with respect to the Application filed herein by the Director of the Public Utility Division of the Commission, and respectfully request the Commission to issue an Order approving this Joint Stipulation and Settlement Agreement.

OKLAHOMA GAS AND ELECTRIC COMPANY

Dated: -------------------- By: ---

Robert D. Stewart, Jr.
William J. Bullard

Rod L. Cook
Rainey, Ross, Rice and Binns

PUBLIC UTILITY DIVISION
OKLAHOMA CORPORATION COMMISSION

Dated: -------------------- By: --

Maribeth D. Snapp, Deputy General Counsel
Miles Halcomb, Assistant General Counsel
Kelli Leaf, Assistant General Counsel

W. A. DREW EDMONDSON
ATTORNEY GENERAL OF THE
STATE OF OKLAHOMA

Dated: -------------------- By: --

Cece Coleman, Assistant Attorney General
William L. Humes, Assistant Attorney General

OKLAHOMA INDUSTRIAL ENERGY CONSUMERS

Dated: -------------------- By: --

J. Fred Gist
Hall, Estill, Hardwick, Gable, Golden & Nelson

James D. Satrom
Thomas P. Schroedter
Hall, Estill, Hardwick, Gable, Golden & Nelson

ENERGETIX, L.L.C.

Dated: -------------------- By: --

Deborah R. Morgan
Energetix, L.L.C.

Cheryl A.Vaught
Vaught & Conner

ONEOK POWER MARKETING COMPANY

Dated: -------------------- By: --

Donald W. England
ONEOK Power Marketing Company

AES SHADY POINT, INC.

Dated: -------------------- By: --

Kendall W. Parrish
Ron Comingdeer & Associates

OKLAHOMA RENEWABLE ENERGY
FOUNDATION

Dated: -------------------- By: --

Cheryl A. Vaught
Scott A. Conner

Vaught & Conner

OG&E SHAREHOLDERS ASSOCIATION

Dated: -------------------- By: --

Ronald E. Stakem
Clark, Stakem, Wood & Patten, P.C.

ONEOK GAS TRANSPORTATION, L.L.C.

Dated: -------------------- By: --

Rob F. Robertson
John M. Benson
Gable & Gotwals

C. Burnett Dunn
Gable & Gotwals