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

FORM 10-Q

(Mark One)
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the quarterly period ended June 30, 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 July 31, 2002, 78,145,561 shares of common stock, par value $0.01 per share were outstanding.

OGE ENERGY CORP.

FORM 10-Q

FOR THE QUARTER ENDED JUNE 30, 2002

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PART I. FINANCIAL INFORMATION

Item 1. Financial Statements

OGE ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	June 30, 2002	December 31, 2001
	(In thousands)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 2,585	$ 32,493
Accounts receivable - customers, less reserve of $11,746 and $8,863, respectively	228,050	205,155
Accrued unbilled revenues	64,200	35,600
Accounts receivable - other	17,454	16,958
Fuel inventories, at LIFO cost	83,860	77,209
Materials and supplies, at average cost	43,306	38,736
Prepayments and other	6,414	41,103
Price risk management	15,825	21,238
Accumulated deferred tax assets	12,322	10,035
Total current assets	474,016	478,527
OTHER PROPERTY AND INVESTMENTS, at cost	75,853	40,318
PROPERTY, PLANT AND EQUIPMENT		
In service	5,624,501	5,507,240
Construction work in progress	49,521	47,812
Total property, plant and equipment	5,674,022	5,555,052
Less accumulated depreciation	2,340,411	2,291,304
Net property, plant and equipment	3,333,611	3,263,748
DEFERRED CHARGES AND OTHER ASSETS		
Advance payments for gas	32,500	8,500
Income taxes recoverable through future rates	37,096	37,615
Intangible asset - unamortized prior service cost	47,318	47,318
Prepaid benefit obligation	6,890	21,315
Price risk management	10,945	13,390
Other	95,273	85,861
Total deferred charges and other assets	230,022	213,999
TOTAL ASSETS	$ 4,113,502	$ 3,996,592

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

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

	June 30, 2002	December 31, 2001

LIABILITIES AND STOCKHOLDERS' EQUITY	(In thousands)	
CURRENT LIABILITIES		
Short-term debt	$ 225,996	$ 115,000
Accounts payable	195,641	153,223
Dividends payable	25,935	25,909
Customers' deposits	30,386	28,423
Accrued taxes	27,528	28,835
Accrued interest	39,334	40,314
Long-term debt due within one year	93,000	115,000
Provision for payments of take or pay gas	425	30,800
Fuel clause over recoveries	8,843	23,358
Price risk management	6,387	7,925
Capital lease obligation	623	408
Other	33,244	30,543
Total current liabilities	687,342	599,738
LONG-TERM DEBT	1,527,475	1,526,303
DEFERRED CREDITS AND OTHER LIABILITIES		
Capital lease obligation - non-current	8,695	8,910
Accrued pension and benefit obligations	101,536	100,086
Accumulated deferred income taxes	668,514	634,946
Accumulated deferred investment tax credits	49,704	52,279
Price risk management	1,431	3,759
Take or pay credit	32,500	8,500
Other	25,196	21,502
Total deferred credits and other liabilities	887,576	829,982
STOCKHOLDERS' EQUITY		
Common stockholders' equity	444,875	444,689
Retained earnings	588,179	617,924
Accumulated other comprehensive income (loss), net of tax	(21,945)	(22,044)
Total stockholders' equity	1,011,109	1,040,569
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$ 4,113,502	$ 3,996,592

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

OGE ENERGY CORP.
CONDENSED CONSOLIDATED STATEMENTS OF INCOME

(Unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
	2002	**2001**	**2002**	**2001**
	(In thousands, except per share data)			
OPERATING REVENUES	$ 752,524	$ 747,891	$ 1,347,614	$ 1,811,478
COST OF GOODS SOLD	521,896	523,507	949,326	1,420,429
Gross margin on revenues	230,628	224,384	398,288	391,049
Other operation and maintenance	99,411	93,442	187,949	191,532
Depreciation and amortization	47,337	44,923	94,320	90,246
Taxes other than income	16,471	16,258	33,343	32,910
OPERATING INCOME	67,409	69,761	82,676	76,361
OTHER INCOME (EXPENSES), NET	(550)	(531)	491	(781)
EARNINGS BEFORE INTEREST AND TAXES	66,859	69,230	83,167	75,580

INTEREST INCOME (EXPENSES)				
Interest income	544	1,458	1,055	2,327
Interest on long-term debt	(21,725)	(24,931)	(43,754)	(51,372)
Interest on trust preferred securities	(4,317)	(4,317)	(8,634)	(8,634)
Allowance for borrowed funds used during construction	327	234	705	417
Other interest charges	(1,580)	(3,512)	(4,155)	(7,218)
Net interest expenses	(26,751)	(31,068)	(54,783)	(64,480)
INCOME BEFORE TAXES	40,108	38,162	28,384	11,100
INCOME TAX EXPENSE	11,738	13,369	6,237	1,275
NET INCOME	$ 28,370	$ 24,793	$ 22,147	$ 9,825
BASIC AND DILUTED AVERAGE COMMON SHARES OUTSTANDING	78,000	77,922	77,996	77,922
BASIC AND DILUTED EARNINGS PER AVERAGE COMMON SHARE	$ 0.36	$ 0.32	$ 0.28	$ 0.13
DIVIDENDS PAID PER SHARE	$ 0.3325	$ 0.3325	$ 0.6650	$ 0.6650

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

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

	Six Months Ended June 30	
	2002	**2001**
	(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 22,147	$ 9,825
Adjustments to reconcile net income to net cash provided from operating activities		
Depreciation and amortization	94,320	90,246
Deferred income taxes and investment tax credits, net	4,574	4,809
Gain on sale of assets	(2,172)	(127)
Change in certain assets and liabilities		
Accounts receivable - customers	(22,895)	164,166
Accrued unbilled revenues	(28,600)	(12,500)
Fuel, materials and supplies inventories	(11,221)	87,732
Accumulated deferred tax assets	(2,287)	(586)
Other current assets	34,192	47,482
Accounts payable	42,418	(138,533)
Accrued taxes	(1,307)	(9,006)
Accrued interest	(980)	(177)
Price risk management	13,493	(4,340)
Other current liabilities	(39,985)	1,670
Other operating activities	(10,754)	6,405
Net Cash Provided from Operating Activities	90,943	247,066
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(158,057)	(126,397)
Proceeds from sale of assets	10,699	489
Other investing activities	(383)	(258)
Net Cash Used in Investing Activities	(147,741)	(126,166)
CASH FLOWS FROM FINANCING ACTIVITIES		
Retirement of long-term debt	(31,000)	(5,766)
Increase (decrease) in short-term debt	110,996	(64,400)
Premium on issuance (retirement) of common stock	186	(125)
Distribution (to) from minority interest	(1,400)	1,449
Obligation under capital lease	---	(278)
Cash dividends declared on common stock	(51,892)	(51,837)
Net Cash Provided from (Used in) Financing Activities	26,890	(120,957)
NET DECREASE IN CASH AND CASH EQUIVALENTS	(29,908)	(57)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	32,493	454

CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 2,585	$ 397
SUPPLEMENTAL DISCLOSURE OF CASH FLOW INFORMATION		
CASH PAID DURING THE PERIOD FOR		
Interest (net of amount capitalized $705 and $417)	$ 58,432	$ 55,327
Income taxes	$ 5,393	$ 5,700
NON-CASH INVESTING AND FINANCING ACTIVITIES		
Interest rate swap	$ (10,135)	$ 11,476
Change in fair-value of long-term debt	$ 10,135	$ (10,992)
Assumption of asset and related debt	$ 34,747	$ ---

The accompanying Notes to 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'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 in Oklahoma, Arkansas and 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. Enogex also has investments in exploration and production of natural gas and oil with properties located primarily in Michigan and Oklahoma. As discussed in Notes 5 and 9, these exploration and production assets are in the process of being sold.

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 present fairly the consolidated financial position of the Company at June 30, 2002 and December 31, 2001, the results of operations for the three and six months ended June 30, 2002 and 2001, and the results of cash flows for the six months ended June 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 six months ended June 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. At June 30, 2002, OG&E had 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 through customer rates over a three-year period. See Note 7 for a further discussion. At June 30, 2002, regulatory assets and regulatory liabilities are being amortized and reflected in rates charged to customers over periods of up to 20 years.

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.

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 Consolidated Statements of Income. Changes in the fair value of effective fair value hedges are recorded in Price Risk Management in the accompanying 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 hedged transaction occurs. Physical delivery contracts, which are deemed to be normal purchases or normal sales, are not accounted for as derivatives.

The Company adopted SFAS No. 133 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 reclassified to earnings as the related hedged transactions occurred. 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 for periods beginning after June 15, 2002. The Company will adopt this new standard effective January 1, 2003. Management has not yet determined what the impact of this new standard will be 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 fair value of the asset. Adoption of SFAS No. 144 is required for financial statements for periods 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 concensus on certain issues covered in Issue No. 02-03, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." EITF 02-03 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 beginning in the first interim period ending after July 15, 2002, with reclassification required for all comparable historical periods presented. EITF 02-03 will impact the amount of revenue presented, however, it will not affect gross margin on revenues. The Company is presently evaluating, but has not yet determined, the amount of revenue that will be affected. Total revenues from energy trading contracts were $318.5 million and $283.6 million for the three months ended June 30, 2002 and 2001, respectively, and $569.2 million and $899.4 million for the six months ended June 30, 2002 and 2001, respectively.

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 or 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 or disposal activities initiated after December 31, 2002. The Company will adopt this new standard effective January 1, 2003. Management has not yet determined what the impact of this new standard will be 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, fair value or foreign currency exposure 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 policies on risk management. Enogex recognizes the gain or loss on enhancement or speculative contracts as market values change in the results of operations. The Company adheres to FASB EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," as amended, 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.

4. Comprehensive Income

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

	Three Months Ended June 30		Six Months Ended June 30	
(In thousands)	**2002**	2001	**2002**	2001
Net income	**$ 28,370**	$ 24,793	**$ 22,147**	$ 9,825
Other comprehensive income (loss), net of tax:				
Transition adjustment	**---**	---	**---**	(16,492)
Change in derivative fair value	**---**	920	**---**	16,653
Reclassification adjustments - contract settlements	**---**	(793)	**(99)**	(2,096)
Total other comprehensive loss, net of tax	**---**	127	**(99)**	(1,935)
Total comprehensive income	**$ 28,370**	$ 24,920	**$ 22,048**	$ 7,890

The components of accumulated other comprehensive income as of June 30, 2002 are as follows:

	June 30, 2002 *(In thousands)*
Minimum pension liability adjustment [($35,800) pretax]	$ (21,945)

5. 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 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.

After a review of Enogex's assets on the basis of their strategic value and other factors, the Company has decided to seek to sell its exploration and production assets by year end 2002. The book value of these assets was approximately $43 million as of June 30, 2002. Reference is made to Note 9 for further discussion of these developments.

6. 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 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 million of 8.125 percent fixed rate debt due, January 15, 2010, to a variable rate based on 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 million of 8.125 percent fixed rate debt due, January 15, 2010, to a variable rate based on 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.

These interest rate swaps qualified as fair value hedges under SFAS No. 133 and meet all requirements for a determination that there was no ineffective portion as allowed under the shortcut method under SFAS No. 133.

Enogex retired $31 million of long-term debt that matured during the three months ended June 30, 2002. This debt consisted of $3 million principal amount of 8.130 percent medium-

term notes due April 16, 2002, $17 million principal amount of 8.125 percent medium-term notes due April 22, 2002, $10 million principal amount of 7.650 percent medium-term notes due May 15, 2002 and $1 million semiannual principal payment of 7.15 percent medium-term notes due June 1, 2018.

7. Commitments and Contingencies

In September 2001, the director of the OCC public utility division filed an application with the OCC to review the rates of OG&E. OG&E's rates had last been formally reviewed in 1996. In the filing, the OCC requested that OG&E submit information in accordance with OCC minimum standard filing requirements by January 28, 2002 for a test year ending September 30, 2001. On January 28, 2002, OG&E filed its response requesting a $22 million annual rate increase. It has been 16 years since OG&E requested a rate increase. Approximately $10.3 million of the requested rate increase relates to enhanced security as a result of the September 11, 2001 terrorist attacks and approximately $11.7 million relates 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 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 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 pending efforts to seek recovery from federal disaster aid or through rates. The OCC's consideration of recovery of these storm costs has been incorporated into OG&E's pending rate review proceeding. 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.

On August 5, 2002, the OCC Staff and all other intervening parties filed responsive testimony regarding OG&E's proposal to recover the $5.4 million of deferred operating costs. The OCC Staff's witness and the witness of the Oklahoma Industrial Energy Consumers ("OIEC") did not support OG&E's proposal to amortize the deferred operating costs over three years. The witness for the Attorney General's office did accept OG&E's proposed three-year recovery of the deferred operating costs. The witness for the OIEC proposed that to the extent OG&E is successful in obtaining federal disaster recovery funds, they should be applied first to these deferred costs. Arguments on the recovery of these deferred costs and the remaining issues of this proceeding are scheduled to be heard before an administrative law judge in late September 2002. While the ultimate recovery is subject to the approval of the OCC, management continues to believe that it is probable that these deferred costs will be recovered in rates if not recovered through federal aid. A final order in OG&E's rate case is not expected until late in 2002. 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.

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"). Operation of the Storage Facility proved beneficial by allowing OG&E to lower fuel costs by base loading coal generation, a less costly fuel supply. During 1996, OG&E completed negotiations and contracted with COOG for gas storage service. Pursuant to the contract, COOG reimbursed OG&E for all outstanding cash advances and interest amounting to approximately $46.8 million. OG&E also entered into a bridge financing agreement as guarantor for COOG. In 1997, COOG obtained permanent financing and issued a note, originally in the amount of $49.5 million. The proceeds from the permanent financing were applied to repay the outstanding bridge financing. In connection with the permanent financing, the Company entered into a note purchase agreement, where it agreed, upon the occurrence of a monetary default by COOG on its permanent financing, to purchase COOG's note from the holders at a price equal to the unpaid principal and interest under the COOG note.

In July 1998, Enogex also agreed to lease underground gas storage from COOG, with the capacity being developed by COOG. This lease agreement was accounted for as a capital lease, and an asset was recorded for $26.5 million, which is being amortized over 40 years. The lease term is five years and includes seven five-year renewal options. As of June 30, 2002, the capital lease obligation was $9.3 million. As part of the Enogex lease, the Company agreed to make up to a $12 million secured loan to an affiliate of COOG (the "COOG Affiliate Loan"). As of June 30, 2002, the amount outstanding under the COOG Affiliate Loan is approximately $8 million. The COOG Affiliate Loan is repayable in 2003 and is 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 borrower is unable to pay the COOG Affiliate Loan, the Company would be required to write off the portion of such loan that has not been repaid. Disputes arose under the lease agreement between Enogex and COOG. The parties arbitrated these disputes pursuant to the terms of the lease agreement. The arbitration panel rendered a decision on February 8, 2002 ("Arbitration Award"). Pursuant to the Arbitration Award, COOG filed with the arbitration panel a Motion to Reconsider the panel's ruling, which was denied by a majority of the panel. Pursuant to proceedings instituted by Enogex with the District Court of Oklahoma County, the Arbitration Award was confirmed and a judgment in the amount of $23.3 million in favor of Enogex and against COOG (the "Judgment") was entered on July 12, 2002.

By letter dated May 9, 2002, COOG advised the holder of its note that the Arbitration Award was in excess of $10 million and, in the event the Arbitration Award became a final, non-appealable order, it would constitute an event of default under the loan agreement relating to the 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 $950,000 and also could be 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 would be a secured creditor, with a first mortgage or comparable security interest on all of COOG's assets. The Company and Enogex have separate rights to purchase the

Storage Facility at prices set by their contracts, which, in the case of Enogex, include the right to offset against such purchase price, among other things, the outstanding amount of the COOG Affiliate Loan. As a result of the events discussed above, the Company recorded a note payable and an asset for $33.8 million.

In December 2001, Enogex, as part of its triennial filing under Section 311 of the Natural Gas Policy Act and due to the merger of the Enogex and Transok pipeline systems, made its filing at FERC to establish (for the combined system) the rates, a treating fee and various other issues, effective January 1, 2002. As part of the review, the FERC Staff has served a number of data requests to which Enogex responded. The FERC Staff, Enogex and the active intervening parties have initiated settlement discussions. Two technical conferences at the FERC have been held and were attended by the FERC Staff, Enogex and active intervening parties. Enogex has also responded to numerous additional formal and informal data requests. Enogex has settled all issues with two parties and continues to negotiate with the other parties. The outstanding issues have narrowed significantly and Enogex is hopeful that the parties will be able to resolve the remaining issues before the FERC Staff's mid-September report to the Commission on this proceeding.

In 2000, Enogex entered into a long-term transportation contract with an independent power producer ("IPP"). The IPP is refusing to make certain payments for the monthly demand fees on grounds of an alleged force majeure event, which the IPP alleges excused it from certain payment obligations. The IPP asserts that no demand payments are due for three and one-half months beginning March 15, 2002, and that effective July 1, 2002, only 50 percent of the monthly demand payment is due based on continued force majeure events. The IPP has advised that the force majeure event should be remedied by November 1, 2002. Enogex has requested and received a prepayment from the IPP, of approximately $683,000, due to the IPP falling below contractual creditworthiness provisions. This prepayment is to be applied to the monthly demand payments becoming due July 1 and thereafter. As of June 30, 2002, the amount of demand revenues due to Enogex was approximately $2.3 million, which have been fully reserved on the Company's financial statements. Additionally, beginning on July 1, 2002, the IPP has made the demand payments for the 50 percent that are not disputed. Enogex asserts that the remaining demand payments are due for all periods since March 15, 2002, and continues to take appropriate action to protect its legal position.

8. 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, marketing electricity, natural gas and natural gas liquids and investing in the development for and production of natural gas and crude oil. 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 June 30, 2002	Electric Utility	Energy Supply	Other Operations	Intersegment	Total

(dollars in thousands)

	Electric Utility	Energy Supply	Other Operations	Intersegment	Total
Operating revenues	$ 352,238	$ 411,802	$ ---	$ (11,516)(A)	$ 752,524
Fuel	112,810	---	---	(8,410)	104,400
Purchased power	65,222	---	---	---	65,222
Gas and electricity purchased for resale	---	330,259	---	(3,106)	327,153
Natural gas purchases - other	---	25,121	---	---	25,121
Cost of goods sold	178,032	355,380	---	(11,516)	521,896
Gross margin on revenues	174,206	56,422	---	---	230,628
Other operation and maintenance	75,468	26,775	(2,832)	---	99,411
Depreciation and amortization	30,293	14,520	2,524	---	47,337
Taxes other than income	11,604	4,236	631	---	16,471
Operating income (loss)	56,841	10,891	(323)	---	67,409
Other income (expenses)	(832)	271	11	---	(550)
Earnings (loss) before interest and taxes	$ 56,009	$ 11,162	$ (312)	$ ---	$ 66,859
Net income	$ 30,839	$ 959	$ 28,380	$ (31,808)	$ 28,370

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

Three Months Ended June 30, 2001	Electric Utility	Energy Supply	Other Operations	Intersegment	Total
(dollars in thousands)					
Operating revenues	$ 359,481	$ 398,204	$ ---	$ (9,794)(A)	$ 747,891
Fuel	119,435	---	---	(9,079)	110,356
Purchased power	70,436	---	---	---	70,436
Gas and electricity purchased for resale	---	291,786	---	(715)	291,071
Natural gas purchases - other	---	51,644	---	---	51,644
Cost of goods sold	189,871	343,430	---	(9,794)	523,507
Gross margin on revenues	169,610	54,774	---	---	224,384
Other operation and maintenance	71,777	25,268	(3,603)	---	93,442
Depreciation and amortization	30,227	12,792	1,904	---	44,923
Taxes other than income	11,456	4,031	771	---	16,258
Operating income	56,150	12,683	928	---	69,761
Other income (expenses)	(500)	(56)	25	---	(531)
Earnings before interest and taxes	$ 55,650	$ 12,627	$ 953	$ ---	$ 69,230
Net income (loss)	$ 28,025	$ (328)	$ 24,792	$ (27,696)	$ 24,793

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

Six Months Ended June 30, 2002	Electric Utility	Energy Supply	Other Operations	Intersegment	Total
(dollars in thousands)					
Operating revenues	$ 614,321	$ 754,408	$ ---	$ (21,115)(A)	$ 1,347,614
Fuel	197,803	---	---	(17,489)	180,314
Purchased power	129,065	---	---	---	129,065
Gas and electricity purchased for resale	---	598,650	---	(3,626)	595,024
Natural gas purchases - other	---	44,923	---	---	44,923
Cost of goods sold	326,868	643,573	---	(21,115)	949,326
Gross margin on revenues	287,453	110,835	---	---	398,288
Other operation and maintenance	140,188	54,228	(6,467)	---	187,949
Depreciation and amortization	61,073	28,307	4,940	---	94,320
Taxes other than income	23,520	8,440	1,383	---	33,343

Operating income	62,672	19,860	144	---	82,676
Other income (expenses)	(1,240)	1,707	24	---	491
Earnings before interest and taxes	$ 61,432	$ 21,567	$ 168	$ ---	$ 83,167
Net income (loss)	$ 29,321	$ (322)	$ 22,179	$ (21,031)	$ 22,147

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

Six Months Ended June 30, 2001	Electric Utility	Energy Supply	Other Operations	Intersegment	Total
(dollars in thousands)					
Operating revenues	$ 686,316	$ 1,148,741	$ ---	$ (23,579)(A)	$ 1,811,478
Fuel	246,397	---	---	(18,159)	228,238
Purchased power	147,405	---	---	---	147,405
Gas and electricity purchased for resale	---	948,020	---	(5,420)	942,600
Natural gas purchases - other	---	102,186	---	---	102,186
Cost of goods sold	393,802	1,050,206	---	(23,579)	1,420,429
Gross margin on revenues	292,514	98,535	---	---	391,049
Other operation and maintenance	143,498	53,657	(5,623)	---	191,532
Depreciation and amortization	60,523	26,079	3,644	---	90,246
Taxes other than income	23,141	8,327	1,442	---	32,910
Operating income	65,352	10,472	537	---	76,361
Other income (expenses)	(1,291)	483	27	---	(781)
Earnings before interest and taxes	$ 64,061	$ 10,955	$ 564	$ ---	$ 75,580
Net income (loss)	$ 27,028	$ (9,944)	$ 9,809	$ (17,068)	$ 9,825

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

9. Subsequent Events

Commitments and Contingencies

As discussed in Note 7, Enogex was awarded a Judgment against COOG in the amount of $23.3 million on July 12, 2002. On August 9, 2002, COOG appealed this Judgment to the Oklahoma Supreme Court. COOG did not, however, post a bond to stay the execution of the Judgment. Therefore, Enogex exercised its asset option to purchase the Storage Facility under the Option Agreement on July 24, 2002, escrowed the transfer documentation and set closing for July 31, 2002. Enogex offset the $4.5 million purchase price against the Judgment. After exercising the set off against COOG's obligation to Enogex under the Judgment, there were no funds to reduce the obligation of the affiliate of COOG under the $8 million COOG Affiliate Loan from the Company. 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 is asserting ownership of the storage facility, pursuant to the terms of its original exercise of the asset option.

Under the terms of the note purchase agreement described in Note 7, the Company was required to purchase COOG's note for approximately $33.8 million in June 2002. The Company is also pursuing the repayment of the COOG Affiliate Loan. While the Company fully believes it will collect all amounts receivable under the COOG Affiliate Loan in the event the borrower is unable to pay the COOG Affiliate Loan, the Company would be required to write off the portion of such loan that has not been repaid.

In further execution on 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 contract with COOG. This garnishment resulted in a collection by Enogex of approximately $983,000, and this amount will be credited as partial satisfaction of the remaining Judgment amount. OG&E believes the remaining lease payments under their contract with COOG and now Enogex is still recoverable through rates.

The Company has recently become 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 not been served with the action and therefore, has not yet filed a response to the allegations. The Company assets that the disputed issues have been properly determined by the Arbitration Panel and that this action is improper.

Long-Term Debt

On August 7, 2002, Enogex entered into a new interest rate swap agreement to convert $100 million of 8.125 percent fixed rate debt due, January 15, 2010, to a variable rate based on LIBOR.

Asset Disposals

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. The effective date of the sale is July 1, 2002 and closing is expected to occur on September 5, 2002. The proceeds from the sale are expected to be approximately $15 million.

Enogex expects to execute an agreement within 30 days on its exploration and production assets located in Michigan and expects to close the transaction in the fourth quarter of 2002.

On August 2, 2002, Ozark Gas Transmission, L.L.C. ("Ozark")(in which Enogex owns a 75 percent interest) entered into an Agreement of Purchase and Sale 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 million.

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 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.

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. As discussed in Notes 5 and 9 to the condensed consolidated financial statements, Enogex also has investments in exploration and production of natural gas and oil with properties located primarily in Michigan and Oklahoma, which assets are in the process of being sold.

Forward-Looking Statements

Except for the historical statements contained herein, some 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, including rate recovery for January 2002 storm damages; 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

The following discussion and analysis presents factors which affected the Company's consolidated results of operations for the three and six months ended June 30, 2002 (the "current periods") as compared to the three and six months ended June 30, 2001 and the Company's consolidated financial position as of June 30, 2002. Due to seasonal fluctuations and other factors, the operating results for the three and six months ended June 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.

The Company reported earnings of $0.36 per share for the three months ended June 30, 2002 compared to earnings of $0.32 per share for the same period in 2001 and earnings of $0.28 per share for the six months ended June 30, 2002 compared to earnings of $0.13 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 operation and maintenance expenses.

OG&E contributed $0.40 per share for the three months ended June 30, 2002 compared to $0.36 per share for the same period in 2001. OG&E's improvement was primarily attributable to growth in OG&E's service territory, partially offset by milder weather and higher operation and maintenance expenses.

Enogex contributed $0.01 per share for the three months ended June 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 offset by a decreased margin in gathering and processing. The margin for exploration and production was relatively flat compared to the same period in 2001. Also contributing to Enogex's improvement were lower interest expense and a higher income tax benefit.

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 $0.05 per share for the three months ended June 30, 2002 compared to a loss of $0.04 per share for the same period in 2001.

OG&E contributed $0.38 per share for the six months ended June 30, 2002 compared to $0.35 per share for the same period in 2001. OG&E's improvement was primarily attributable to growth in OG&E's service territory, lower operation and maintenance expenses and lower interest expense.

Enogex contributed $0.00 per share for the six months ended June 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, marketing and trading and gathering and processing offset by a decreased margin in exploration and production. Also contributing to Enogex's improvement was lower interest expense offset by a lower income tax benefit.

The results on a stand-alone basis of the Company (i.e., as a holding company), reflect a loss of $0.09 per share for the six months ended June 30, 2002 and 2001.

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 Note 7 to the condensed consolidated financial statements for a discussion of recent actions.

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 expected 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.

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 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.

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. Reference is made to Note 7 to the condensed consolidated financial statements for a description of the agreement and to Note 9 to the condensed consolidated financial statements for a discussion of recent actions related to such agreement.

2002 Outlook

The Company previously projected 2002 earnings at $1.60 to $1.80 per share. Due to a mild summer so far in the electric utility service area and the continuing weak commodity price environment, the Company has revised its 2002 earnings estimate to $1.40 to $1.50 per share. The Company expects to maintain its annual dividend of $1.33 per share. The Company's earnings estimate for 2002 does not include any of the approximately $92 million in expenditures

associated with the January 2002 ice storm, which, as discussed previously, are currently being capitalized or deferred.

Results of Operations

	Three Months Ended June 30		Six Months Ended June 30	
(In thousands, except per share data)	**2002**	2001	**2002**	2001
Operating income...........................	**$ 67,409**	$ 69,761	**$ 82,676**	$ 76,361
Earnings before interest and taxes.........	**$ 66,859**	$ 69,230	**$ 83,167**	$ 75,580
Average common shares outstanding..........	**78,000**	77,922	**77,996**	77,922

Earnings per average common share	**$ 0.36**	$ 0.32	**$ 0.28**	$ 0.13
Dividends paid per share	**$ 0.3325**	$ 0.3325	**$ 0.6650**	$ 0.6650

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 Consolidated Statements of Income. For the three months ended June 30, 2002, operating income was $67.4 million compared to $69.8 million for the same period in 2001 and EBIT was $66.9 million compared to $69.2 million for the same period in 2001. For the six months ended June 30, 2002, operating income was $82.7 million compared to $76.4 million for the same period in 2001 and EBIT was $83.2 million compared to $75.6 million for the same period in 2001.

EBIT by Business Segment

	Three Months Ended June 30		Six Months Ended June 30	
(In thousands)	**2002**	2001	**2002**	2001
OG&E (Electric Utility)	**$ 56,009**	$ 55,650	**$ 61,432**	$ 64,061
Enogex (Energy Supply)	**11,162**	12,627	**21,567**	10,955
Other operations (1)	**(312)**	953	**168**	564
Consolidated EBIT	**$ 66,859**	$ 69,230	**$ 83,167**	$ 75,580

(1) Other operations primarily include unallocated corporate expenses.

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

OG&E

	Three Months Ended June 30		Six Months Ended June 30	
(In thousands)	**2002**	2001	**2002**	2001
Operating revenues	**$ 352,238**	$ 359,481	**$ 614,321**	$ 686,316
Fuel	**112,810**	119,435	**197,803**	246,397
Purchased power	**65,222**	70,436	**129,065**	147,405
Gross margin on revenues	**174,206**	169,610	**287,453**	292,514
Other operating expenses	**117,365**	113,460	**224,781**	227,162
Operating income	**56,841**	56,150	**62,672**	65,352
Other expenses, net	**(832)**	(500)	**(1,240)**	(1,291)
EBIT	**$ 56,009**	$ 55,650	**$ 61,432**	$ 64,061
System sales - MWH(a)	**5,953**	5,952	**11,532**	11,556
Off-system sales - MWH	**42**	94	**177**	161
Total sales - MWH	**5,995**	6,046	**11,709**	11,717

(a) Megawatt-hour

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

OG&E's EBIT for the three months ended June 30, 2002 increased approximately $0.3 million or 0.6 percent as compared to the same period in 2001. The increase in EBIT was primarily the result of growth in OG&E's service territory, offset by timing differences in the recovery of lower fuel cost expenses from Arkansas customers, milder weather and higher operation and maintenance expenses.

Gross margin on revenues ("gross margin") for the three months ended June 30, 2002 increased approximately $4.6 million or 2.7 percent as compared to the same period in 2001. The gross margin increased by approximately $12.3 million for the three months ended June 30, 2002 as compared to the same period in 2001, due to growth in OG&E's service territory. Partially offsetting this increase was a reduction of approximately $4.3 million for the three months ended June 30, 2002 as compared to the same period in 2001, due to lower recoveries of fuel costs from Arkansas customers through that state's automatic fuel adjustment clause. 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. Cooling degree days were 14.7 percent lower for the three months ended June 30, 2002 as compared to the same period in 2001, resulting in approximately a $2.4 million reduction to the gross margin. Lower levels of natural gas transportation cost that OG&E was allowed to recover from its customers decreased the gross margin by approximately $0.5 million for the three months ended June 30, 2002 as compared to the same period in 2001, as a result of the Acquisition Premium Credit Rider ("APC Rider") and the Gas Transportation Credit Rider

("GTAC Rider"). Lower recoveries under the Generation Efficiency Performance Rider ("GEP Rider") decreased the gross margin by approximately $0.4 million for the three months ended June 30, 2002 as compared to the same period in 2001. Lower kilowatt-hour sales to other utilities and power marketers decreased the gross margin by approximately $0.1 million for the three months ended June 30, 2002 as compared to the same period in 2001.

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 June 30, 2002, fuel expense decreased approximately $6.6 million or 5.5 percent as compared to the same period in 2001, primarily due to a 14.1 percent decrease in the average cost of fuel per kilowatt-hour (particularly the cost of natural gas). Purchased power costs decreased approximately $5.2 million or 7.4 percent for the three months ended June 30, 2002 as compared to the same period in 2001, due to a 17.1 percent decrease in the volume of energy purchased and a 10.0 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 include operating and maintenance expense, depreciation and amortization expense, and taxes other than income. OG&E's operating and maintenance expense increased approximately $3.7 million or 5.1 percent for the three months ended June 30, 2002 as compared to the same period in 2001. This increase was primarily due to an increase of approximately $6.5 million in contract labor costs. Partially offsetting this increase were decreases of approximately $1.9 million in bad debt expense and approximately $0.9 million in miscellaneous corporate expenses.

Depreciation and amortization expense increased approximately $0.1 million or 0.2 percent for the three months ended June 30, 2002 as compared to the same period in 2001, due to a higher level of depreciable plant. Taxes other than income increased approximately $0.1 million or 1.3 percent for the three months ended June 30, 2002 as compared to the same period in 2001, due to higher ad valorem tax accruals.

Six months ended June 30, 2002 compared to Six months ended June 30, 2001

OG&E's EBIT for the six months ended June 30, 2002 decreased approximately $2.6 million or 4.1 percent as compared to the same period in 2001. The decrease in EBIT was

primarily the result of timing differences in the recovery of lower fuel cost expenses from Arkansas customers, milder weather and the loss of revenue resulting from the January 2002 ice storm. Partially offsetting this decrease was growth in OG&E's service territory and lower operation and maintenance expenses.

Gross margin for the six months ended June 30, 2002 decreased approximately $5.1 million or 1.7 percent as compared to the same period in 2001. Approximately $11.4 million of the decrease for the six months ended June 30, 2002 as compared to the same period in 2001, was due to lower recoveries of fuel costs from Arkansas customers through that state's automatic fuel adjustment clause. Cooling degree days were 11.2 percent lower for the six months ended June 30, 2002 as compared to the same period in 2001, resulting in approximately a $3.2 million reduction to the gross margin. Although total expenditures from the January 2002 ice storm, of approximately $92 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 six months ended June 30, 2002. Lower levels of natural gas transportation cost that OG&E was allowed to recover from its customers decreased the gross margin by approximately $1.1 million for the six months ended June 30, 2002 as compared to the same period in 2001, as a result of the APC Rider and the GTAC Rider. Lower recoveries under the GEP Rider decreased the gross margin by approximately $0.8 million for the six months ended June 30, 2002 as compared to the same period in 2001. Lower off-system sales decreased the gross margin by approximately $0.4 million for the six months ended June 30, 2002 as compared to the same period in 2001. Partially offsetting these decreases was an increase of approximately $13.3 million for the six months ended June 30, 2002 as compared to the same period in 2001, due to growth in OG&E's service territory.

Cost of goods sold for OG&E decreased approximately $66.9 million or 17.0 percent for the six months ended June 30, 2002 as compared to the same period in 2001, primarily due to a 26.2 percent decrease in the average cost of fuel per kilowatt-hour (particularly the cost of natural gas). Purchased power costs decreased approximately $18.3 million or 12.4 percent for the six months ended June 30, 2002 as compared to the same period in 2001, due to a 15.0 percent decrease in the volume of energy purchased and a 19.6 percent decrease in the cost of purchased energy.

OG&E's operating and maintenance expenses decreased approximately $3.3 million or 2.3 percent for the six months ended June 30, 2002 as compared to the same period in 2001. This decrease was primarily due to a decrease of approximately $6.1 million in bad debt expense, a decrease of approximately $1.2 million in professional services expense, a decrease of approximately $1.0 million in employee pension and benefit costs and a decrease of approximately $8.9 million in miscellaneous corporate expenses. Partially offsetting these decreases were increases of approximately $12.3 million in contract labor costs and approximately $1.6 million in materials and supplies expense.

Depreciation and amortization expense increased approximately $0.1 million or 0.9 percent for the six months ended June 30, 2002 as compared to the same period in 2001, due to a higher level of depreciable plant. Taxes other than income increased approximately $0.3 million or 1.6 percent for the six months ended June 30, 2002 as compared to the same period in 2001, due to higher ad valorem tax accruals.

Enogex

	Three Months Ended June 30		Six Months Ended June 30	
(Dollars in thousands)	**2002**	2001	**2002**	2001
Operating revenues........................	**$ 411,802**	$ 398,204	**$ 754,408**	$ 1,148,741
Gas and electricity purchased for resale...	**330,259**	291,786	**598,650**	948,020
Natural gas purchases - other.............	**25,121**	51,644	**44,923**	102,186
Gross margin on revenues..................	**56,422**	54,774	**110,835**	98,535
Other operating expenses..................	**45,531**	42,091	**90,975**	88,063
Operating income..........................	**10,891**	12,683	**19,860**	10,472
Other income (expenses), net..............	**271**	(56)	**1,707**	483
EBIT......................................	**$ 11,162**	$ 12,627	**$ 21,567**	$ 10,955
Physical System Supply - MMcfd(a)..........	**1,618**	1,655	**1,657**	1,752
Natural gas processed - MMcfd.............	**624**	730	**630**	740
Natural gas liquids sold - thousand gallons................................	**118,230**	154,447	**225,793**	268,873
Average sales price per gallon............	**$ 0.396**	$ 0.502	**$ 0.369**	$ 0.557
Fractionation spread per MMBtu(b)..........	**$ 1.000**	$ 1.080	**$ 0.864**	$ 0.547
Natural gas marketed - Bbtu(c)............	**94,096**	57,975	**192,396**	141,405
Average sales price per Bbtu..............	**$ 3.238**	$ 4.474	**$ 2.908**	$ 6.028
Power marketed - MWH......................	**457,017**	410,675	**723,930**	721,586
Average sales price per MWH...............	**$ 27.907**	$ 51.160	**$ 27.318**	$ 47,950
Natural gas produced - Mmcfe(d)...........	**1,222**	1,326	**2,519**	2,795
Average sales price per Mcfe(e), net of hedging.............................	**$ 3.391**	$ 4.043	**$ 2.855**	$ 6.225

(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.

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

Enogex's EBIT for the three months ended June 30, 2002 was $11.2 million, which was $1.5 million lower than the same period in 2001. This decrease was primarily attributable to a decreased margin in gathering and processing, partially offset by increased margins in

transportation and storage and marketing and trading. The margin for exploration and production was relatively flat compared to the same period in 2001.

During the three months ended June 30, 2002, gathering and processing posted a loss of $0.9 million to the Enogex EBIT, which was a decrease of $4.5 million from the same period in 2001. The decrease in EBIT is primarily due to lower sales volumes of 19 percent and 23 percent, respectively, for gathering and processing, which accounted for $3.5 million of the decrease in EBIT for the three months ended June 30, 2002. Also contributing to the decrease in EBIT was a $0.7 million loss related to less favorable fractionation spreads during the three months ended June 30, 2002. 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 June 30, 2002, 14.1 million gallons were rejected compared to 19.6 million gallons in the same period in 2001. The average fractionation spread realized for the three months ended June 30, 2002 was $1.000 per MMBtu compared to $1.080 per MMBtu for the same period in 2001. The remaining $0.3 million decrease to EBIT is primarily from higher operating expenses during the three months ended June 30, 2002.

During the three months ended June 30, 2002, the transportation pipeline and storage facilities contributed $9.9 million, or 88.4 percent of the Enogex EBIT, which was an increase of $2.7 million from the same period in 2001. The increased contribution to EBIT is primarily due to a reduction in fuel expense of $4.4 million associated with operating the pipeline due to lower natural gas prices during the three months ended June 30, 2002 compared to the same period in 2001. Also contributing to the increased EBIT was a $1.2 million increase in storage revenues. Partially offsetting these increases to EBIT was a $1.5 million increase in operating expenses and a

$0.9 million decrease in transportation revenues for the three months ended June 30, 2002. The remaining $0.5 million decrease to EBIT is due to higher depreciation and amortization expense and taxes other than income during the three months ended June 30, 2002.

During the three months ended June 30, 2002, marketing and trading contributed less than $0.1 million of the Enogex EBIT, which was an increase of $0.4 million from the same period in 2001. In the prior year period, marketing and trading posted a loss of $0.4 million to Enogex's EBIT. The increased contribution to EBIT is primarily due to increased natural gas sales margins of $3.9 million for the three months ended June 30, 2002 due to increased volumes and lower natural gas prices. 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. Partially offsetting the increased natural gas sales margin was a $1.7 million increase in depreciation and amortization expense related to a write off due to renegotiation of a natural gas sales contract and a $0.6 million loss related to a storage facility.

The remaining $1.2 million decrease to EBIT is primarily from increased operating expenses and other income and expenses during the three months ended June 30, 2002.

During the three months ended June 30, 2002, exploration and production contributed $2.2 million of the Enogex EBIT, which was relatively flat compared to the same period in 2001. EBIT decreased $2.0 million related to lower natural gas sales caused by lower natural gas prices for the three months ended June 30, 2002. Offsetting this decrease were hedging losses of $0.8 million in the prior year period which did not occur during the three months ended June 30, 2002. The remaining $1.2 million increase to EBIT is primarily from lower depreciation and amortization expense and lower exploration and operating expenses during the three months ended June 30, 2002. The exploration and production assets are in the process of being sold.

Six months ended June 30, 2002 compared to Six months ended June 30, 2001

Enogex's EBIT for the six months ended June 30, 2002 was $21.6 million, which was $10.6 million higher than the same period in 2001. This increase was primarily attributable to increased margins in transportation and storage, marketing and trading and gathering and processing offset by a decreased margin in exploration and production.

During the six months ended June 30, 2002, the transportation pipeline and storage facilities contributed $20.2 million, or 93.5 percent of the Enogex EBIT, which was an increase of $11.6 million from the same period in 2001. The increased contribution to EBIT is primarily due to a reduction in fuel expense of $12.3 million associated with operating the pipeline, due to lower natural gas prices during the six months ended June 30, 2002 compared to the same period in 2001. Also contributing to the increased EBIT was a $2.5 million increase in storage revenues. Partially offsetting these increases to EBIT was a $1.6 million increase in operating expenses and a $0.8 million increase in minority interest expense for the six months ended June 30, 2002. The remaining $0.8 million decrease to EBIT is due to higher depreciation and amortization expense and taxes other than income during the six months ended June 30, 2002.

During the six months ended June 30, 2002, marketing and trading contributed $0.1 million of the Enogex EBIT, which was an increase of $5.6 million from the same period in 2001. In the prior year period, marketing and trading contributed a loss of $5.5 million to Enogex's EBIT. The increased contribution to EBIT is primarily due to increased natural gas sales margins of $9.7 million for the six months ended June 30, 2002 due to increased volumes and lower natural gas prices. 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. Partially offsetting the increased natural gas sales margin was a $1.7 million increase in depreciation and amortization expense related to a write off due to renegotiation of a natural gas sales contract and a $0.6 million loss related to a storage facility. The remaining $1.8 million decrease to EBIT is primarily from increased operating expenses and other income and expenses during the six months ended June 30, 2002.

During the six months ended June 30, 2002, gathering and processing posted a loss of $1.0 million to the Enogex EBIT, which was an increase of $1.5 million from the same period in 2001. The improvement in EBIT is primarily due to a $4.7 million gain related to more favorable fractionation spreads during the six months ended June 30, 2002. In order to minimize the impact of low fractionation spreads, ethane and propane were rejected whenever possible. During the six months ended June 30, 2002, 45.7 million gallons were rejected compared to 84.7 million gallons in the same period in 2001. The average fractionation spread realized for the six months ended June 30, 2002 was $0.864 per MMBtu compared to $0.547 per MMBtu for the same period in 2001. Also contributing to the improved EBIT was 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 six months ended June 30, 2002. Offsetting the improvements in EBIT were lower sales volumes of seven percent and 16 percent, respectively, for gathering and processing, which accounted for $4.8 million of the decrease in EBIT for the six months ended June 30, 2002. The remaining $0.2 million increase to EBIT is primarily from lower operating expenses offset by higher depreciation and amortization expense during the six months ended June 30, 2002.

During the six months ended June 30, 2002, exploration and production contributed $2.3 million of the Enogex EBIT, which was a decrease of $8.1 million from the same period in 2001. The decreased EBIT is primarily due to a decrease of $8.3 million related to lower natural gas sales caused by lower natural gas prices for the six months ended June 30, 2002. Also contributing to the decreased EBIT were hedging gains of $1.8 million in the prior year period which did not occur in the six months ended June 30, 2002. The remaining $2.0 million increase to EBIT is primarily from lower depreciation and amortization expense, taxes other than income and exploration and operating expenses during the six months ended June 30, 2002.

Consolidated Net Interest Expense and Tax Expense

Net interest expense includes interest income, interest expense and other interest charges. Net interest expense decreased approximately $4.3 million or 13.9 percent for the three months ended June 30, 2002 as compared to the same period in 2001. This decrease was primarily due to a $3.2 million decrease in interest expense related to the retirement of $31 million in debt during the three months ended June 30, 2002. Also contributing to the decrease was a $1.2 million decrease in interest expense related to lower commercial paper borrowings during the three months ended June 30, 2002. The remaining $0.1 million increase is comprised of individually insignificant items.

Income tax expense decreased approximately $1.6 million or 12.2 percent for the three months ended June 30, 2002 as compared to the same period in 2001 primarily 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 contributing to the decrease was a refund of Oklahoma State income tax related to Oklahoma investment tax credits. These decreases were

partially offset by higher pre-tax income for the three months ended June 30, 2002 as compared to the same period in 2001.

Net interest expense decreased approximately $9.7 million or 15.0 percent for the six months ended June 30, 2002 as compared to the same period in 2001. This decrease was primarily due to a $7.0 million decrease related to a reduction of interest expense from entering into interest rate swap agreements in 2001 and the retirement of $31 million in debt during the three months ended June 30, 2002. Also contributing to the decrease was a $3.3 million decrease in interest expense related to lower commercial paper borrowings during the six months ended June 30, 2002. The remaining $0.6 million increase is comprised of individually insignificant items.

Income tax expense increased approximately $5.0 million for the six months ended June 30, 2002 as compared to the same period in 2001 primarily from a smaller pre-tax loss at Enogex and slightly higher pre-tax income at OG&E. This overall higher pre-tax income 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.

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 million. OG&E has requested the OCC to include in its existing rate case relief from the approximately $92 million in damages caused by the ice storm. OG&E has requested a $14.5 million annual increase in revenue requirement. The request includes 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. The area of damage is within counties that were declared a federal disaster area. Therefore, OG&E is also seeking recovery of a portion of the storm damages from the Federal government with the assistance of the OCC and the Oklahoma Congressional delegation. The expenditures for restoration of the transmission and distribution infrastructure have been capitalized as part of the Company's Property, Plant and Equipment or deferred pending recovery through regulation or other alternatives.

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 six months ended June 30, 2002 were $158.0 million and were financed with internally generated funds and short-term borrowings.

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.

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 Part II, Item 1 - "Legal Proceedings" of this Form 10-Q, to Part II, Item 1 - "Legal Proceedings" in the Company's Form 10-Q for the quarter ended March 31, 2002 and to "Management's Discussion and Analysis" 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 Consolidated Financial Statements and Notes to Consolidated Financial Statements included in this Form 10-Q and in the Company's Form 10-K for the year ended December 31, 2001 contains 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 energy trading purchases and sales contracts, pension plan assumptions, gas storage inventory, unbilled revenue for the electric utility, allowance for uncollectible accounts receivable and contingency reserves.

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, monitors 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 mark-to-market, 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.

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 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.

Gas storage inventory used in trading activities by Enogex 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.

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.

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 generally accepted accounting principles, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's financial statements.

Regulation and Rates

OG&E's retail electric tariffs in Oklahoma are regulated by the OCC, and in Arkansas by the APSC. 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 in accordance with OCC minimum standard filing requirements by January 28, 2002 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 million annual rate increase. If granted, the increase would be the first for OG&E since 1985. Over the past 16 years, OG&E has had several rate reductions that have totaled more than $142 million annually.

Attempting to make security investments at the proper level, OG&E has developed a set of guidelines aimed at minimizing 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 is for investment in increased system reliability and for increased utility costs. OG&E has added new generation capacity to meet growing customer demand and has determined a need to increase expenditures for distribution system reliability that has been brought about, in no small part, by 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 has 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 energy, then offering that power to customers. The rate would reflect the higher cost of wind-generated power. Also included in the filing was OG&E's offer to not seek a rate increase for three years.

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 million. On April 8, 2002, OG&E announced it would request the OCC to withdraw the $10.3 million increased security portion of its January request for a $22 million annual rate increase. OG&E is working with the OCC Staff under a joint filing to determine the appropriate dollar amount for security upgrades and recovery mechanisms.

On June 11, 2002 the OCC Staff and other intervening parties filed responsive testimony. In their testimony, the OCC Staff proposed adjustments that amounted to a $17.4 million annual rate reduction, Oneok Gas Transmission recommended a $29.4 million annual rate reduction, the Oklahoma Industrial Energy Consumers ("OIEC"), an industry trade group, recommended a $103.8 million annual rate reduction and the Office of the Oklahoma Attorney General ("Attorney General") recommended a $105.8 million annual rate reduction.

On July 1, 2002 OG&E filed direct testimony in support of recovery for the approximately $92 million in damages caused by the January 2002 ice storm. OG&E has requested a $14.5 million annual increase in revenue requirement. The request includes 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.

On July 15, 2002 OG&E and all other parties to the case filed rebuttal testimony. In their testimony OG&E cited many erroneous adjustments in the OIEC's and Attorney General's recommendation. After removing what OG&E believes are erroneous adjustments, the OIEC's recommendation would be reduced to a $29.3 million annual rate reduction and the Attorney General's recommendation would be reduced to a $33.4 million annual rate reduction. OG&E's rebuttal testimony also challenged most of the remaining proposals of the Attorney General and the OIEC. Surrebuttal testimony will be filed on August 15, 2002.

On August 5, 2002 the OCC Staff and all other intervening parties filed responsive testimony regarding return on equity, capital structure, rate design and the cost of the January 2002 ice storm. Each party updated their recommendations that were filed on June 11, 2002. The OCC Staff recommended a $39.1 million rate reduction and proposed an incentive mechanism based on OG&E's success at generating electricity with its coal plants. The Attorney General's consultants revised its June 11, 2002 recommendation of a $105.8 million rate reduction to $96.3 million. The OIEC increased its originally proposed $103.8 million rate reduction by recommending a lesser return on equity and lower equity portion of the capital structure. The OIEC's recommendations included only a small portion of the 2002 ice storm damage cost. The OIEC's filed testimony did not calculate a final rate reduction recommendation. OG&E has estimated the rate reduction proposed by the OIEC to be approximately $120 million. A final order in OG&E's rate case is not expected until late in 2002.

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 is 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 by: (i) allowing OG&E to collect one-third of the amount by which its fuel costs were below a specified percentage (96.261 percent) of the average fuel costs of certain other investor-owned utilities in the region; and (ii) disallowing the collection of one-third of the amount by which its fuel costs exceeded a specified percentage (103.739 percent) of the average fuel costs of other investor-owned utilities. The modifications enacted in June 2000 had the effect of reducing the amount OG&E could recover under the GEP Rider by: (i) changing OG&E's peer group to include utilities with a higher coal-to-gas generation mix; (ii) reducing the amount of fuel costs that can be recovered if OG&E's costs exceed the new peer group by changing the percentage above which OG&E will not be allowed to recover one-third of the fuel costs from Oklahoma customers from 103.739 percent to 101.0 percent; (iii) reducing OG&E's share of cost savings as compared to its new peer group from 33 percent to 30 percent; and (iv) limiting to $10.0 million the amount of any awards paid to OG&E or penalties charged to OG&E. For the period between July 1, 2001 and June 30, 2002, OG&E recovered $5.1 million under the GEP Rider. The GEP Rider expired in June 2002, however, the OCC could approve a similar reward mechanism requested by OG&E in its rate case.

The final action addresses the competitive bid process of OG&E's gas transportation needs following which OG&E's affiliate, Enogex, contracted to provide gas transportation service to all of OG&E's generation plants. In the 1997 Order, the OCC approved a stipulation wherein OG&E agreed to initiate a competitive bidding process for gas transportation service to its gas-fired plants, with the competitive services commencing no later than April 30, 2000. The order also set annual compensation for the transportation services provided by Enogex to OG&E at $41.3 million annually until March 1, 2000, at which time the rate would drop to $28.5 million

(reflecting removal of the APC Rider, upon the completion of the recovery from customers of the amortization premium paid by OG&E when it acquired Enogex in 1986) and remain at that level until competitively-bid gas transportation began. In July 1999, OG&E filed an application with the OCC requesting approval of a performance-based rate plan for its Oklahoma retail customers from April 2000 until the introduction of customer choice for electric power scheduled for July 2002. As part of this application, OG&E stated that Enogex had submitted the only viable bid ($33.4 million per year) for gas transportation to OG&E's six gas-fired power plants that were the subject of the competitive bid. As part of its application to the OCC, OG&E offered to discount Enogex's bid from $33.4 million annually to $25.2 million annually. OG&E executed a gas transportation contract with Enogex under which Enogex continues to serve the needs of OG&E's power plants at a price to be paid by OG&E of $33.4 million annually and, if OG&E's proposal had been approved by the OCC, OG&E would have recovered a portion of such amount ($25.2 million) from its customers. OG&E negotiated with the OCC Staff, the Office of the Oklahoma Attorney General and a coalition of industrial customers in an effort to settle all issues (including the competitive bid process) associated with its application for a performance-based rate plan. When these negotiations failed, OG&E withdrew its application, which withdrawal was approved by the OCC in December 1999.

In July 2000, OG&E entered into a stipulation (the "Stipulation") with the OCC Staff, the Office of the Attorney General and a coalition of industrial customers regarding the competitive bid process of OG&E's gas transportation service. In June 2001, the OCC approved the Stipulation declaring the Stipulation to be fair, just and reasonable and representing a reasonable settlement of the issues and thereby serving the public interest. OG&E had previously collected $28.5 million on an annual basis through its base rate and APC Rider for gas transportation services from Enogex for the power plant requirements covered by the competitive bid. The Stipulation permits OG&E to recover $25.2 million annually for the gas transportation services provided by Enogex pursuant to the competitive bid process. The Stipulation directs 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, and will remain in effect until amended by OG&E at the direction of the OCC.

In December 2001, Enogex, as part of its triennial filing under Section 311 of the Natural Gas Policy Act and due to the merger of the Enogex and Transok pipeline systems, made its filing at FERC to establish (for the combined system) the rates, a treating fee and various other issues, effective January 1, 2002. As part of the review, the FERC Staff has served a number of data requests to which Enogex responded. The FERC Staff, Enogex and the active intervening parties have initiated settlement discussions. Two technical conferences at the FERC have been held and were attended by the FERC Staff, Enogex and active intervening parties. Enogex has also responded to numerous additional formal and informal data requests. Enogex has settled all issues with two parties and continues to negotiate with the other parties. The outstanding issues have narrowed significantly and Enogex is hopeful that the parties will be able to resolve the

remaining issues before the FERC Staff's mid-September report to the Commission on this proceeding.

State Restructuring Initiatives

Oklahoma: 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.

Arkansas: In April 1999, Arkansas passed a law ("the Restructuring Law") calling for restructuring of the electric utility industry at the retail level. The Restructuring Law, 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 reclassified to earnings as the related hedged transactions occurred. 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 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 million of 8.125 percent fixed rate debt due, January 15, 2010, to a variable rate based on 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 million of 8.125 percent fixed rate debt due, January 15, 2010, to a variable rate based on 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 life of the related debt.

These interest rate swaps qualified as fair value hedges under SFAS No. 133 and meet all requirements for a determination that there was no ineffective portion as allowed under the shortcut method under SFAS No. 133.

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 June 30, 2002
Fixed rate debt						
Principal amount...	$ 6.3	$ 53.0	$ 153.0	$ 860.6	$1,072.9	$1,177.5

Weighted-average interest rate....	7.53%	7.22%	7.09%	7.48%	7.41%	---
Variable rate debt						
Principal amount...	---	---	---	$ 457.1	$ 457.1	$ 457.1
Weighted-average interest rate....	---	---	---	4.14%	4.14%	---

(A) Does not include current portion of long-term debt.

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 June 30, 2002:

(In thousands)	Trading	Non-Trading
Commodity market risk, net...........	$ 5	$ ---

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Reference is made to 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 quarter ended March 31, 2002 for a description of certain legal proceedings presently pending. 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, except as set forth below:

Reference is made to Note 10 of the Company's Consolidated Financial Statements included in Item 8 of the Company's Annual Report on Form 10-K for the year ended December 31, 2001 and Part II, Item 1 of the Company's Form 10-Q for the quarter ended March 31, 2002 for a discussion of the agreements between Central Oklahoma Oil and Gas Corp. ("COOG") and OG&E and between COOG and Enogex.

On July 12, 2002, the District Court of Oklahoma County (the "Court") held its hearing on the Motion to Settle and Application to Dissolve Seal. At the hearing, the Court (1) entered its Order Dissolving Seal as to all filed documents except the Storage Lease Agreement; (2) entered an Order Confirming Arbitration Award and directing judgment be entered; and (3) entered its judgment awarding Enogex a judgment against COOG in the amount of $23.3 million. As set forth in Notes 7 and 9 to the condensed consolidated financial statements, Enogex has initiated actions to execute on this judgment. The Company has recently become 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 not been served with the action and therefore, has not yet filed a response to the allegations. The Company asserts that the disputed issues have been properly determined by the Arbitration Panel and that this action is improper.

In early 2002, a dispute arose between Enogex and Dynegy Marketing and Trade ("Dynegy") when Dynegy asserted that the term of an existing storage agreement was three (3) years rather than one (1) year as set forth in the agreement. On March 22, 2002, Enogex filed a Complaint against Dynegy seeking a declaratory judgment determining the rights, duties and obligation of the parties under the Agreement. Thereafter, Dynegy and Enogex attempted to resolve the dispute and the Complaint was not served on Dynegy until July 3, 2002. On July 23, 2002 Dynegy filed an answer and counterclaims against Enogex asserting declaratory relief, breach of contract, fraud, conversion and unjust enrichment. Dynegy claims that its damages relating to the conversion claim exceed $9 million. Enogex asserts that pursuant to the Agreement, after the expiration of the term of the Agreement (and a further 60 day withdrawal period) that the title to the gas remaining in the storage facility automatically passes to Enogex. The Company intends to vigorously defend these counterclaims.

Reference is made to Note 7 to the condensed consolidated financial statements to the condensed consolidated financial statements for a discussion of a commercial dispute between Enogex and an independent power producer.

Item 4. Submission of Matters To A Vote of Security Holders

(a) The Company's Annual Meeting of Shareowners was held on May 16, 2002.

(b) Not applicable.

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

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

Herbert H. Champlin - 66,183,069 votes for election and 966,547 votes withheld

Martha W. Griffin - 66,082,693 votes for election and 1,066,923 votes withheld

Ronald H. White, M.D. - 60,210,525 votes for election and 6,939,091 votes withheld

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits
None

(b) Reports on Form 8-K
The Company filed a Current Report on Form 8-K on May 21, 2002 to report the replacement of the Company’s independent public accountants.

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)

August 14, 2002