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 March 31, 2003

OR

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

Commission File Number: 1-12579

OGE ENERGY CORP.

(Exact name of registrant as specified in its charter)

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

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

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

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

Indicate by check mark whether the registratrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes__X__No___

As of April 30, 2003, 79,218,054 shares of common stock, par value $0.01 per share, were outstanding.

OGE ENERGY CORP.

FORM 10-Q

FOR THE QUARTER ENDED MARCH 31, 2003

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Item 1. Financial Statements

OGE ENERGY CORP.
CONDENSED CONSOLIDATED BALANCE SHEETS
(Unaudited)

	March 31, 2003	December 31, 2002
	(In millions)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 20.8	$ 44.4
Accounts receivable, net	376.8	304.6
Accrued unbilled revenues	32.5	28.2
Fuel inventories	67.7	99.7
Materials and supplies, at average cost	39.6	42.6
Price risk management	45.3	17.1
Pipeline imbalance	6.0	34.3
Accumulated deferred tax assets	10.2	10.9
Fuel clause under recoveries	48.8	14.7
Other	7.1	10.6
Current assets of discontinued operations	0.2	4.7
Total current assets	655.0	611.8
OTHER PROPERTY AND INVESTMENTS, at cost	28.2	27.2
PROPERTY, PLANT AND EQUIPMENT		
In service	5,540.8	5,500.2
Construction work in progress	37.7	44.8
Total property, plant and equipment	5,578.5	5,545.0
Less accumulated depreciation	2,265.1	2,231.4
Net property, plant and equipment	3,313.4	3,313.6
In service of discontinued operations	---	54.2
Less accumulated depreciation	---	11.4
Net property, plant and equipment of discontinued operations	---	42.8
Net property, plant and equipment	3,313.4	3,356.4
DEFERRED CHARGES AND OTHER ASSETS		
Recoverable take or pay gas charges	32.5	32.5
Income taxes recoverable from customers, net	33.6	34.8
Intangible asset - unamortized prior service cost	42.7	42.7
Prepaid benefit obligation	37.1	44.9
Price risk management	19.4	20.1
Other	78.1	80.8
Deferred charges and other assets of discontinued operations	---	0.2
Total deferred charges and other assets	243.4	256.0
TOTAL ASSETS	$4,240.0	$4,251.4

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

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

	March 31, 2003	December 31, 2002
	(In millions)	
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	$ 173.0	$ 275.0
Accounts payable	387.6	269.0
Dividends payable	26.2	26.1
Customers' deposits	34.0	33.0
Accrued taxes	13.7	23.6
Accrued interest	28.2	35.7
Tax collections payable	6.8	6.7
Accrued vacation	17.4	16.9
Long-term debt due within one year	33.0	21.0
Price risk management	35.9	13.9
Pipeline imbalance	4.7	9.4
Other	22.2	19.4
Current liabilities of discontinued operations	0.2	2.0
Total current liabilities	782.9	751.7
LONG-TERM DEBT	1,490.1	1,501.9
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued pension and benefit obligations	188.3	184.2
Accumulated deferred income taxes	620.4	627.0
Accumulated deferred investment tax credits	45.8	47.1
Accrued removal obligations, net	111.0	109.3
Price risk management	1.7	0.6
Provision for payments of take or pay gas	32.5	32.5
Other	5.5	4.1
Deferred credits and other liabilities of discontinued operations	---	9.1
Total deferred credits and other liabilities	1,005.2	1,013.9
STOCKHOLDERS' EQUITY		
Common stockholders' equity	457.7	453.5
Retained earnings	578.2	604.7
Accumulated other comprehensive loss, net of tax	(74.1)	(74.3)
Total stockholders' equity	961.8	983.9
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$4,240.0	$4,251.4

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

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

	Three Months Ended March 31, 2003	2002
	(In millions, except per share data)	
OPERATING REVENUES		
Electric Utility operating revenues	$ 332.6	$ 262.1
Natural Gas Pipeline operating revenues	717.6	313.7
Total operating revenues	1,050.2	575.8
COST OF GOODS SOLD		
Electric Utility cost of goods sold	203.9	139.7
Natural Gas Pipeline cost of goods sold	664.5	274.0

Total cost of goods sold	868.4	413.7
Gross margin on revenues	181.8	162.1
Other operation and maintenance	90.3	85.1
Depreciation	46.6	45.2
Taxes other than income	17.2	16.7
OPERATING INCOME	27.7	15.1
OTHER INCOME (EXPENSE)		
Other income	6.1	0.8
Other expense	(2.9)	(1.3)
Net other income (expense)	3.2	(0.5)
INTEREST INCOME (EXPENSE)		
Interest income	0.2	0.5
Interest on long-term debt	(19.0)	(22.0)
Interest on trust preferred securities	(4.3)	(4.3)
Allowance for borrowed funds used during construction	0.2	0.4
Interest on short-term debt and other interest charges	(1.8)	(2.6)
Net interest expense	(24.7)	(28.0)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE TAXES	6.2	(13.4)
INCOME TAX EXPENSE (BENEFIT)	1.9	(5.1)
INCOME (LOSS) FROM CONTINUING OPERATIONS BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	4.3	(8.3)
DISCONTINUED OPERATIONS		
Income from discontinued operations	2.2	1.7
Income tax expense (benefit)	0.9	(0.4)
Income from discontinued operations	1.3	2.1
INCOME (LOSS) BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	5.6	(6.2)
CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING FOR ENERGY TRADING CONTRACTS, NET OF TAX OF $3.7	(5.9)	---
NET LOSS	$ (0.3)	$ (6.2)
BASIC AVERAGE COMMON SHARES OUTSTANDING	78.7	78.0
DILUTED AVERAGE COMMON SHARES OUTSTANDING	78.9	78.0
BASIC EARNINGS (LOSS) PER AVERAGE COMMON SHARE		
Income (loss) from continuing operations	$ 0.05	$ (0.11)
Income from discontinued operations, net of tax	0.02	0.03
Loss from cumulative effect of accounting change, net of tax	(0.07)	---
NET LOSS	$ ---	$ (0.08)
DILUTED EARNINGS (LOSS) PER AVERAGE COMMON SHARE		
Income (loss) from continuing operations	$ 0.05	$ (0.11)
Income from discontinued operations, net of tax	0.02	0.03
Loss from cumulative effect of accounting change, net of tax	(0.07)	---
NET LOSS	$ ---	$ (0.08)

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

OGE ENERGY CORP.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

	Three Months Ended March 31,	
	2003	**2002**
	(In millions)	
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Loss	$ (0.3)	$ (6.2)
Adjustments to reconcile net loss to net cash provided from		

operating activities		
Income from discontinued operations	(1.3)	(2.1)
Cumulative effect of change in accounting principle	5.9	---
Depreciation	46.6	45.2
Deferred income taxes and investment tax credits, net	(0.5)	22.7
Gain on sale of assets	(5.7)	(0.5)
Ineffectiveness of interest rate swap	---	0.2
Price risk management assets	(27.2)	13.8
Price risk management liabilities	23.0	0.7
Other assets	8.2	(0.9)
Other liabilities	0.3	1.7
Change in certain current assets and liabilities		
Accounts receivable, net	(72.2)	(29.2)
Accrued unbilled revenues	(4.3)	4.8
Fuel, materials and supplies inventories	25.5	(3.7)
Pipeline imbalance asset	28.3	(4.5)
Fuel clause under recoveries	(34.1)	---
Other current assets	3.5	3.8
Accounts payable	118.5	45.4
Customers' deposits	1.0	1.2
Accrued taxes	(6.3)	(15.9)
Accrued interest	(7.5)	(10.0)
Fuel clause over recoveries	---	5.4
Pipeline imbalance liability	(4.6)	3.2
Other current liabilities	1.2	4.0
Net Cash Provided from Operating Activities	98.0	79.1
CASH FLOWS FROM INVESTING ACTIVITIES		
Capital expenditures	(44.9)	(84.9)
Proceeds from sale of assets	9.9	0.5
Other investing activities	(0.4)	(0.3)
Net Cash Used in Investing Activities	(35.4)	(84.7)
CASH FLOWS FROM FINANCING ACTIVITIES		
Decrease in short-term debt, net	(102.0)	(18.0)
Premium on issuance of common stock	4.2	0.1
Distribution to minority interest	(2.5)	---
Dividends paid on common stock	(23.9)	(25.9)
Net Cash Used in Financing Activities	(124.2)	(43.8)
DISCONTINUED OPERATIONS		
Net cash (used in) provided from operating activities	(0.5)	20.3
Net cash provided from (used in) investing activities	38.5	(2.8)
Net Cash Provided from Discontinued Operations	38.0	17.5
NET DECREASE IN CASH AND CASH EQUIVALENTS	(23.6)	(31.9)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	44.4	37.5
CASH AND CASH EQUIVALENTS AT END OF PERIOD	$ 20.8	$ 5.6

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

OGE ENERGY CORP.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Summary of Significant Accounting Policies

Organization

OGE Energy Corp. (collectively with its subsidiaries, the “Company”) is an energy and energy services provider offering physical delivery and management of both electricity and natural gas in the south central United States. The Company conducts these activities through two business segments, the Electric Utility and the Natural Gas Pipeline segments. All significant intercompany transactions have been eliminated in consolidation.

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

The Natural Gas Pipeline segment is conducted through Enogex Inc. and its subsidiaries ("Enogex") and consists of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing and trading of natural gas. The vast majority of Enogex's natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. Through a 75 percent interest in the NOARK Pipeline System Limited Partnership, Enogex also owns a controlling interest in and operates the Ozark Gas Transmission System ("Ozark"), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. Enogex's marketing and trading activities include corporate price risk management and other optimization services. Enogex was previously engaged in the exploration and production of natural gas, however, this portion of Enogex's business, along with interests in certain gas gathering and processing assets in Texas, were sold in 2002 and in the first quarter of 2003 and are reported in the condensed consolidated financial statements as discontinued operations.

The Company allocates operating costs to its affiliates based on several factors. Operating costs directly related to specific affiliates are assigned to those affiliates. Where more than one affiliate benefits from certain expenditures, the costs are shared between those affiliates receiving the benefits. Operating costs incurred for the benefit of all affiliates are allocated among the affiliates, based primarily upon head-count, occupancy, usage or the "Distragas" method. The Distragas method is a three-factor formula that uses an equal weighting of payroll, operating income and assets. The Company believes this method provides a reasonable basis for allocating common expenses.

Basis of Presentation

The condensed consolidated financial statements included herein have been prepared by the Company, without audit, pursuant to the rules and regulations of the Securities and Exchange Commission. Certain information and footnote disclosures normally included in financial statements prepared in accordance with accounting principles generally accepted in the United States have been condensed or omitted pursuant to such rules and regulations; however, the Company believes that the disclosures are adequate to prevent the information presented from being misleading.

In the opinion of management, all adjustments necessary to fairly present the consolidated financial position of the Company at March 31, 2003 and December 31, 2002, and the results of its operations and cash flows for the three months ended March 31, 2003 and 2002, have been included and are of a normal recurring nature.

Due to seasonal fluctuations and other factors, the operating results for the three months ended March 31, 2003 are not necessarily indicative of the results that may be expected for the year ending December 31, 2003 or for any future period. 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, 2002.

Accounting Records

The accounting records of OG&E are maintained in accordance with the Uniform System of Accounts prescribed by the FERC and adopted by the OCC and the APSC. Additionally, OG&E, as a regulated utility, is subject to the accounting principles prescribed by the Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards ("SFAS") No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 provides that certain costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment. At March 31, 2003 and December 31, 2002, regulatory assets of approximately $60.4 million and approximately $63.9 million, respectively, are being amortized and reflected in rates charged to customers over periods of up to 20 years. At March 31, 2003 and December 31, 2002, regulatory liabilities of approximately $111.0 million and approximately $109.3 million, respectively, have been reclassified from Accumulated Depreciation in accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations."

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

the amount is approved by a regulatory authority, then the amount is reclassified as a regulatory liability.

The following table is a summary of the Company's regulatory assets and liabilities at:

(In millions)	**March 31, 2003**	December 31, 2002
Regulatory Assets		
Income taxes recoverable from customers, net.........	**$ 33.6**	$ 34.8
Unamortized loss on reacquired debt..................	**23.0**	23.3
January 2002 ice storm...............................	**3.6**	5.4
Miscellaneous..	**0.2**	0.4
Total Regulatory Assets.............................	**$ 60.4**	$ 63.9

Regulatory Liabilities		
Accrued removal obligations, net	**$ 111.0**	$ 109.3
Total Regulatory Liabilities	**$ 111.0**	$ 109.3

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

Accrued removal obligations represent asset retirement costs previously recovered from ratepayers for other than legal obligations. In accordance with SFAS No. 143, the Company was required to reclassify the accrued removal obligations, which had previously been recorded as a liability in Accumulated Depreciation, to a regulatory liability. See Note 2 for a further discussion.

Management continuously monitors the future recoverability of regulatory assets. When in management's judgment future recovery becomes impaired, the amount of the regulatory asset is reduced or written off, as appropriate.

If the Company were required to discontinue the application of SFAS No. 71 for some or all of its operations, it could result in writing off the related regulatory assets and liabilities; the financial effects of which could be significant.

Use of Estimates

In preparing the condensed consolidated financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the condensed consolidated financial

statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the Company's condensed consolidated financial statements. In management's opinion, the areas of the Company where the most significant judgment is exercised are in the valuation of pension plan assumptions, impairment estimates, contingency reserves, unbilled revenue for OG&E, the allowance for uncollectible accounts receivable, the valuation of energy purchase and sale contracts and gas storage inventory.

Allowance for Uncollectible Accounts Receivable

For OG&E, all customer balances are written off if not collected within six months after the account is finalized. The allowance for uncollectible accounts receivable for OG&E 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 the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. For Enogex, customer balances are written off when the Company concludes the required payment of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable for Enogex is established on a case-by-case basis when the Company believes the required payment of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable was approximately $11.7 million and $13.6 million at March 31, 2003 and December 31, 2002, respectively.

Impairment of Assets

The Company assesses potential impairments of assets when there is evidence that events or changes in circumstances indicate that an asset's carrying value may not be recoverable. An impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset.

Income Taxes

The Company files consolidated income tax returns. Income taxes are allocated to each affiliate 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 follows the provisions of SFAS No. 109, "Accounting for Income Taxes," which uses an asset and liability approach to accounting for income taxes. Under SFAS No. 109, deferred tax assets or liabilities are computed based on the difference between the financial statement and income tax bases of assets and liabilities using the enacted marginal tax rate. Deferred income tax expenses or benefits are based on the changes in the asset or liability from period to period.

Cash and Cash Equivalents

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

Revenue Recognition

OG&E

OG&E reads its customers' meters and sends bills to its customers 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. An amount is accrued as a receivable for this unbilled revenue based on estimates of usage and prices during the period. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

Enogex

The Company recognizes revenue from natural gas gathering and processing and transportation and storage services to third parties as services are provided. Revenue associated with natural gas liquids is recognized when the production is processed and sold. Substantially all of OGE Energy Resources, Inc.'s ("OERI") natural gas and power marketing contracts qualify as derivatives and, therefore, are accounted for at fair value as prescribed in SFAS No. 133 "Accounting for Derivative Instruments and Hedging Activities," as amended. Under fair value accounting, fixed-price forwards, swaps, options, futures and other financial instruments with third parties are recorded at estimated fair market values, net of reserves, with the corresponding market changes in fair value recognized in earnings and offsetting amounts recorded as Price Risk Management assets and liabilities in the accompanying Condensed Consolidated Balance Sheets. See Note 2 for a further discussion.

Automatic Fuel Adjustment Clauses

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component in the cost-of-service for ratemaking, are passed through to OG&E's customers through automatic fuel adjustment clauses, which are subject to periodic review by the OCC, the APSC and the FERC.

Fuel Inventories

OG&E

Fuel inventories for the generation of electricity consist of coal, natural gas and oil. These inventories are accounted for under the last-in, first-out ("LIFO") cost method. The estimated replacement cost of fuel inventories was higher than the stated LIFO cost by

approximately $36.0 million and $7.0 million at March 31, 2003 and December 31, 2002, respectively, based on the average cost of fuel purchased.

Enogex

Effective January 1, 2003, gas storage inventory used in OERI's trading activities are accounted for at the lower of cost or market in accordance with the guidance in Emerging Issues Task Force ("EITF") Issue No. 02-3, "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities," which resulted in the rescission of EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," as amended. Prior to January 1, 2003, this inventory was accounted for on a fair value accounting basis utilizing a gas index that in management's opinion approximated the current market value of natural gas in that region as of the Balance Sheet date. In order to minimize risk, OERI may enter into contracts or hedging instruments to hedge the fair value of this inventory. If these contracts qualify for hedge accounting under SFAS No. 133, the hedged portion of the inventory is recorded at fair value with an offsetting gain or loss recorded currently in earnings. The fair value of the hedging instrument is also recorded on the books of the Company as a Price Risk Management asset or liability with an offsetting gain or loss recorded in current earnings. At March 31, 2003, the Company had no qualified fair value hedges under SFAS No. 133 for natural gas inventory. Natural gas inventories used in OERI's trading activities, which are valued at the lower of cost or market, were approximately $2.4 million at March 31, 2003. See Note 2 for a further discussion.

Stock-Based Compensation

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

The following table reflects pro forma net loss and loss per average common share had the Company elected to adopt the fair value based method of SFAS No. 123:

	Three Months Ended March 31,	
	2003	2002

	(In millions, except per share data)	
Net loss, as reported	**$ (0.3)**	$ (6.2)
Add:		
Stock-based employee compensation expense included in reported net loss, net of related tax effects	**---**	---
Deduct:		
Stock-based employee compensation expense determined under fair value based method for all awards, net of related tax effects	**0.4**	0.3
Pro forma net loss	**$ (0.7)**	$ (6.5)
Loss per average common share		
Basic - as reported	**$ ---**	$ (0.08)
Basic - pro forma	**$ (0.01)**	$ (0.08)
Diluted - as reported	**$ ---**	$ (0.08)
Diluted - pro forma	**$ (0.01)**	$ (0.08)

Reclassifications

Certain prior year amounts have been reclassified on the condensed consolidated financial statements to conform to the 2003 presentation.

2. Accounting Pronouncements

In June 2001, the FASB issued SFAS No. 143, which applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. SFAS No. 143 affects the Company's accrued plant removal costs for generation, transmission, distribution and processing facilities and requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of the fair value can be made. If a reasonable estimate of the fair value cannot be made in the period the asset retirement obligation is incurred, the liability shall be recognized when a reasonable estimate of the fair value can be made. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes, written or oral contracts, including obligations arising under the doctrine of promissory estoppel. The recognition of an asset retirement obligation is capitalized as part of the carrying amount of

the long-lived asset. Asset retirement obligations represent future liabilities and, as a result, accretion expense is accrued on this liability until such time as the obligation is satisfied. Adoption of SFAS No. 143 is required for financial statements issued for fiscal years beginning after June 15, 2002. The Company adopted this new standard effective January 1, 2003 and the adoption of this new standard did not have a material impact on its consolidated financial position or results of operations. In connection with the adoption of SFAS No. 143, the Company assessed whether it had a legal obligation within the scope of SFAS No. 143. The Company determined that it had a legal obligation to retire certain assets. As the Company currently has no plans to retire any of these assets and the remaining life is indeterminable, an asset retirement obligation was not recognized; however, the Company will monitor these assets and record a liability when a reasonable estimate of the fair value can be made. As described below, amounts recovered from ratepayers related to estimated asset retirement obligations recorded as a liability in Accumulated Depreciation were reclassified as a regulatory liability in the first quarter of 2003.

SFAS No. 143 also requires that, if the conditions of SFAS No. 71 are met, a regulatory asset or liability should be recorded to recognize differences between asset retirement costs recorded under SFAS No. 143 and legal or other asset retirement costs recognized for ratemaking purposes. Upon adoption of SFAS No. 143, the Company was required to quantify the amount of asset retirement costs previously recovered from ratepayers for other than legal obligations and reclassify those differences as regulatory assets or liabilities. At December 31, 2002, approximately $109.3 million had been previously recovered from ratepayers and recorded as a liability in Accumulated Depreciation related to estimated asset retirement obligations. This balance was reclassified as a regulatory liability on the December 31, 2002 Condensed Consolidated Balance Sheet.

In July 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." SFAS No. 146 addresses financial accounting and reporting for costs associated with exit and disposal activities and supersedes EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 requires recognition of a liability for a cost associated with an exit or disposal activity when the liability is incurred, as opposed to when the entity commits to an exit plan under EITF 94-3. SFAS No. 146 also establishes that the liability should initially be measured and recorded at fair value. Adoption of SFAS No. 146 is required for exit and disposal activities initiated after December 31, 2002. The Company adopted this new standard effective January 1, 2003 and the adoption of this new standard did not have a material impact on its consolidated financial position or results of operations.

In October 2002, the EITF reached a consensus on certain issues covered in EITF 02-3. One consensus of EITF 02-3 requires that all mark-to-market gains and losses, whether realized or unrealized, on financial derivative contracts as defined in SFAS No. 133 be shown net in the Income Statement for financial statements issued for periods beginning after December 15, 2002, with reclassification required for prior periods presented. The Company adopted this consensus effective January 1, 2003 and the application of this consensus did not have a material impact on its consolidated financial position or results of operations as this consensus supports the Company's historical presentation of financial derivative contracts.

In October 2002, the EITF reached a consensus to rescind EITF 98-10 effective for fiscal periods beginning after December 15, 2002. Effective October 25, 2002, all new contracts and physical inventories that would have been accounted for under EITF 98-10 are no longer marked to market through earnings unless the contracts meet the definition of a derivative under SFAS No. 133. Application of the consensus for energy contracts and inventory that existed on or before October 25, 2002 that remained in effect at the date this consensus was initially applied was recognized as a cumulative effect of a change in accounting principle in accordance with APB Opinion No. 20, “Accounting Changes.” As a result, only energy contracts that meet the definition of a derivative in SFAS No. 133 will be carried at fair value. The Company adopted this consensus effective January 1, 2003 resulting in an approximate $9.6 million pre-tax loss ($5.9 million after tax). The loss, which was accounted for as a cumulative effect of a change in accounting principle, was primarily related to natural gas held in storage for trading purposes. This natural gas held in storage was sold during the first quarter of 2003 resulting in an increase in gross margin on revenues in excess of the cumulative effect loss described above.

In December 2002, the FASB issued SFAS No. 148, “Accounting for Stock-Based Compensation - Transition and Disclosure - an amendment of FASB Statement No. 123.” SFAS No. 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation which includes the prospective method, modified prospective method and retroactive restatement method. SFAS No. 148 also amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. Adoption of the annual disclosure and voluntary transition requirements of SFAS No. 148 is required for annual financial statements issued for fiscal years ending after December 15, 2002. Adoption of the interim disclosure requirements of SFAS No. 148 is required for interim periods beginning after December 15, 2002. Pursuant to the provisions of SFAS No. 123, the Company has elected to continue using the intrinsic value method of accounting for its stock-based employee compensation plans in accordance with APB 25. See “Stock-Based Compensation” in Note 1 for a further discussion.

3. Price Risk Management Assets and Liabilities

Non-Trading Activities

The Company periodically utilizes derivative contracts to manage exposure to unfavorable changes in commodity prices, as well as to reduce exposure to adverse interest rate fluctuations. During the three months ended March 31, 2003 and 2002, the Company’s use of non-trading price risk management instruments primarily involved the use of interest rate swap agreements to hedge the Company’s exposure to interest rate risk by converting a portion of the Company’s fixed rate debt to a floating rate. These agreements involve the receipt of fixed rate amounts in exchange for floating rate interest payments over the life of the agreement without an

exchange of the underlying principal amount. In addition, the Company utilized certain fixed price swap instruments to hedge the price to be received for excess fuel recovered from customers as well as to hedge portions of the Company’s exposure to natural gas liquids prices and natural gas storage activities.

In accordance with SFAS No. 133, the Company recognizes all of its derivative instruments as Price Risk Management assets or liabilities in the Balance Sheet at fair value with such amounts classified as current or long-term based on their anticipated settlement. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and resulting designation. For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative instrument as well as the offsetting gain or loss on the hedged item attributable to the hedged risk are recognized in the same line item associated with the hedged item in current earnings during the period of the change in fair values. For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of Accumulated Other Comprehensive Income and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portion of a derivative’s change in fair value is recognized currently in earnings. Hedge effectiveness is measured at least quarterly based on the relative changes in fair value between the derivative contract and hedged item during the period of hedge designation. Forecasted transactions designated as the hedged item in a cash flow hedge are regularly evaluated to assess whether they continue to be probable of occurring. If the forecasted transactions are no longer probable of occurring, any gain or loss deferred in Accumulated Other Comprehensive Income is recognized currently in earnings. The Company’s interest rate swap agreements have been designated as fair value hedges and qualified for the shortcut method prescribed by SFAS No. 133. Under the shortcut method, the Company assumes that the hedged item’s change in fair value is exactly as much as the derivative’s change in fair value.

At March 31, 2003, the Company had outstanding cash flow hedges and approximately a $0.2 million after tax gain was included in Accumulated Other Comprehensive Loss. At December 31, 2002, the Company had no outstanding cash flow hedges, and no amounts were included in Accumulated Other Comprehensive Loss related to cash flow hedges.

Trading Activities

The Company, through its subsidiary, OERI, engages in energy trading activities primarily related to the purchase and sale of natural gas and electricity as well as certain other commodities. Contracts utilized in these activities generally include forward and swap contracts, over-the-counter and exchange traded options and storage and transportation contracts. Under the guidance provided by SFAS No. 133, financial instruments that qualify as derivatives are reflected at fair value with the resulting unrealized gains and losses recorded as Price Risk Management assets or liabilities in the accompanying Condensed Consolidated Balance Sheets, classified as current or long-term based on their anticipated settlement. Unrealized gains and losses from changes in the market value of open contracts are included in Natural Gas Pipeline operating revenues in the Condensed Consolidated Statements of Operations. Energy trading

contracts resulting in delivery of a commodity that meet the requirements of EITF Issue No. 99-19, "Reporting Revenues Gross as a Principal or Net as an Agent," are included as sales or purchases in the accompanying Condensed Consolidated Statements of Operations depending on whether the contract relates to the sale or purchase of the commodity. See Note 2 for a further discussion of the accounting for the Company's energy trading activities.

4. Comprehensive Loss

The components of total comprehensive loss for the three months ended March 31, 2003 and 2002, respectively, are as follows:

	Three Months Ended March 31,	
(In millions)	**2003**	2002
Net loss	**$ (0.3)**	$ (6.2)
Other comprehensive income (loss), net of tax:		
Deferred hedging gains (losses)	**0.2**	(0.1)
Total comprehensive loss	**$ (0.1)**	$ (6.3)

Accumulated other comprehensive loss at both March 31, 2003 and December 31, 2002 included approximately a $74.3 million after tax loss ($121.3 million pre-tax) related to a minimum pension liability adjustment. Also included at March 31, 2003 was approximately a $0.2 million after tax gain related to outstanding cash flow hedges.

5. Discontinued Operations

On March 25, 2002, Enogex entered into an Agreement of Sale and Purchase with West Texas Gas, Inc. to sell all of its interests in Belvan Corp., Belvan Limited Partnership and Todd Ranch Limited Partnership ("Belvan") for approximately $9.8 million. The effective date of the sale was January 1, 2002 and the closing occurred on March 28, 2002. The Company recognized approximately a $1.6 million after tax gain related to the sale of these assets.

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

On November 14, 2002, Enogex entered into an Agreement of Sale and Purchase with Quicksilver Resources, Inc. to sell all of its exploration and production assets located in Michigan for approximately $32.0 million. The effective date of the sale was July 1, 2002 and the closing occurred on December 2, 2002. The Company recognized approximately a $2.9 million after tax gain related to the sale of these assets.

During the third quarter of 2002, the Company decided to sell all of its interests in the NuStar Joint Venture ("NuStar"). On January 23, 2003, Enogex entered into an Agreement of Sale and Purchase with Benedum Gas Partners, L.P. to sell all of the interests of its subsidiary, Enogex Products Corporation, in the west Texas properties consisting of NuStar, which has operations consisting of the extraction and sale of natural gas liquids, for approximately $37.0 million. The effective date of the sale was January 1, 2003 and the closing occurred on February 18, 2003. The Company recognized approximately a $1.4 million after tax gain in the first quarter of 2003 related to the sale of these assets, which is recorded in Income from Discontinued Operations in the accompanying Condensed Consolidated Statements of Operations.

The condensed consolidated financial statements of the Company have been restated to reflect Enogex's exploration and production assets, NuStar and Belvan, all of which were part of the Natural Gas Pipeline segment, as discontinued operations. Accordingly, revenues, costs and expenses, assets, liabilities and cash flows of the exploration and production assets, NuStar and Belvan have been excluded from the respective captions in the condensed consolidated financial statements and have been reported as "Current Assets of Discontinued Operations", "Net Property, Plant and Equipment of Discontinued Operations", "Deferred Charges and Other Assets of Discontinued Operations", "Current Liabilities of Discontinued Operations", "Deferred Credits and Other Liabilities of Discontinued Operations", "Income from Discontinued Operations" and "Net Cash Provided from Discontinued Operations."

Summarized financial information for the discontinued operations is as follows:

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS DATA

(In millions)	Three Months Ended March 31, 2003	2002
Operating revenues from discontinued operations.........	$ **7.8**	$ 19.4
Income from discontinued operations before taxes........	$ **2.2**	$ 1.7

CONDENSED CONSOLIDATED BALANCE SHEET DATA

(In millions)	March 31, 2003	December 31, 2002
Accounts receivable.....................................	$ **0.2**	$ 4.1
Other current assets....................................	**---**	0.6
Total current assets of discontinued operations........	$ **0.2**	$ 4.7
Plant in service of discontinued operations.............	**---**	54.2
Less accumulated depreciation........................	**---**	11.4
Net property, plant and equipment of discontinued operations..	$ **---**	$ 42.8
Total deferred charges and other assets of discontinued operations................................	$ **---**	$ 0.2
Accounts payable..	**---**	1.1
Accrued taxes...	**---**	0.4
Other current liabilities...............................	**0.2**	0.5
Total current liabilities of discontinued operations...	$ **0.2**	$ 2.0
Total deferred credits and other liabilities of discontinued operations................................	$ **---**	$ 9.1

6. Asset Disposals

On August 2, 2002, Ozark, in which an Enogex subsidiary owns a 75 percent interest, entered into an Agreement of Sale and Purchase with CenterPoint Energy Gas Transmission Co. to sell approximately 29 miles of transmission lines of the Ozark pipeline located in Pittsburg and Latimer counties in Oklahoma for approximately $10.0 million. On November 18, 2002, the Company received FERC approval for the closing, which occurred on January 6, 2003. The Company recognized approximately a $5.3 million pre-tax gain in the first quarter of 2003 related to the sale of these assets, which is recorded in Other Income in the accompanying Condensed Consolidated Statements of Operations. These assets were part of the Natural Gas Pipeline segment.

7. Supplemental Cash Flow Information

Non-cash financing activities for the three months ended March 31, 2003 and 2002 included approximately $0.2 million and $4.5 million, respectively, related to the change in fair value of the interest rate swap agreements and the corresponding change in long-term debt.

Cash payments for interest, net of interest capitalized of approximately $0.2 million and $0.4 million, respectively, were approximately $32.3 million and $36.6 million for the three months ended March 31, 2003 and 2002, respectively. Cash payments for income taxes, net of income tax refunds, were approximately $2.6 million for the three months ended March 31, 2003. Cash refunds related to income taxes, net of income tax payments, were approximately $26.0 million for the three months ended March 31, 2002.

8. Common Stock

For the three months ended March 31, 2003, the Company issued 242,020 shares of new common stock pursuant to the Company’s Automatic Dividend Reinvestment and Stock Purchase Plan. For the three months ended March 31, 2002, there were 5,066 shares of new common stock issued pursuant to the Stock Incentive Plan, which related to exercised stock options.

9. Earnings Per Share

For the three months ended March 31, 2003, there were 0.3 million shares of employee stock options, which were included in the computation of diluted earnings per average common share. No employee stock options were included in the computation of diluted earnings per average common share for the three months ended March 31, 2002. For the three months ended March 31, 2003 and 2002, respectively, approximately 2.3 million shares and 2.5 million shares subject to issuance related to employee stock options are not included in the calculation of adjusted average common shares outstanding for diluted earnings per average common share because the effect of including those shares is anti-dilutive.

10. Long-Term Debt

Interest Rate Swap Agreements

At March 31, 2003 and December 31, 2002, the Company had three outstanding interest rate swap agreements: (i) OG&E entered into an interest rate swap agreement, effective March 30, 2001, to convert $110.0 million of 7.30 percent fixed rate debt due October 15, 2025, to a variable rate based on the three month London InterBank Offering Rate ("LIBOR") and (ii) Enogex entered into two separate interest rate swap agreements, effective July 15, 2002 and October 24, 2002, to convert $100.0 million each of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the six month LIBOR.

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

At March 31, 2003 and December 31, 2002, the fair values pursuant to the interest rate swaps were approximately $16.1 million and $15.9 million, respectively, and are included in non-current Price Risk Management assets in the accompanying Condensed Consolidated Balance Sheets. A corresponding net increase of approximately $16.1 million and $15.9 million is reflected in Long-Term Debt at March 31, 2003 and December 31, 2002, respectively, as these fair value hedges were effective at March 31, 2003 and December 31, 2002.

Security Ratings

On January 15, 2003, Standard & Poor’s Ratings Services (“Standard & Poor’s”) lowered the credit ratings of OGE Energy Corp.‘s, OG&E’s and Enogex’s senior unsecured debt from A- to BBB+. OGE Energy Corp.‘s short-term commercial paper ratings were affirmed at A-2. The Company may experience somewhat higher borrowing costs but does not expect the actions by Standard & Poor’s to have a significant impact on the Company’s consolidated financial position or results of operations.

On February 5, 2003, Moody’s Investors Service (“Moody’s”) lowered the credit ratings of OGE Energy Corp.'s senior unsecured debt to Baa1 from A3, OG&E's senior unsecured debt to A2 from A1 and Enogex's senior unsecured debt to Baa3 from Baa2. OGE Energy Corp.‘s short-term commercial paper rating was unchanged at P-2. The Company may experience somewhat higher borrowing costs but does not expect the actions by Moody’s to have a significant impact on the Company’s consolidated financial position or results of operations. As a result of Enogex’s rating being lowered to Baa3, OGE Energy Corp. was required to issue a $5.0 million guarantee on Enogex’s behalf for a counterparty. At March 31, 2003, there is no outstanding liability balance related to this guarantee.

A security rating is not a recommendation to buy, sell or hold securities. Such rating may be subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

11. Short-Term Debt

Consolidated short-term debt of approximately $173.0 million and $275.0 million, respectively, was outstanding at March 31, 2003 and December 31, 2002. The following table shows the Company’s lines of credit in place at March 31, 2003. Short-term borrowings will consist of a combination of bank borrowings and commercial paper.

Lines of Credit *(In millions)*

Entity	Amount	Maturity
OGE Energy Corp. (A)	$ 200.0	January 8, 2004
	100.0	January 15, 2004
	15.0	April 6, 2004
OG&E	100.0	June 26, 2003
Total	$ 415.0	

(A) The lines of credit at OGE Energy Corp. are used to back up the Company's commercial paper borrowings, which were approximately $139.2 million at March 31, 2003. No borrowings were outstanding at March 31, 2003 under any of the lines of credit shown above.

The Company’s ability to access the commercial paper market could be adversely impacted by a commercial paper ratings downgrade. The lines of credit contain ratings triggers that require annual fees and borrowing rates to increase if the Company suffers an adverse ratings impact. The impact of additional downgrades of the Company’s rating 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.

Unlike the Company and Enogex, OG&E must obtain regulatory approval from the FERC in order to borrow on a short-term basis. OG&E has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time.

12. Report of Business Segments

The Company's Electric Utility operations are conducted through OG&E, a regulated utility engaged in the generation, transmission, distribution and sale of electric energy. The Company's Natural Gas Pipeline operations are conducted through Enogex. Enogex is engaged in the transportation and storage of natural gas, the gathering and processing of natural gas and the marketing and trading of natural gas. Enogex also has been involved in investing in the development for and production of natural gas and crude oil, which investments Enogex sold during 2002. Other Operations primarily includes unallocated corporate expenses and interest expense on commercial paper and the Trust Originated Preferred Securities. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by

regulatory considerations. The following tables are a summary of the results of the Company's business segments for the three months ended March 31, 2003 and 2002.

Three Months Ended March 31, 2003	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	**$ 332.6**	**$ 739.6**	**$ ---**	**$ (22.0)**	**$ 1,050.2**
Fuel	**141.2**	**---**	**---**	**(10.0)**	**131.2**
Purchased power	**72.7**	**---**	**---**	**---**	**72.7**
Gas and electricity purchased for resale	**---**	**657.0**	**---**	**(12.0)**	**645.0**
Natural gas purchases - other	**---**	**19.5**	**---**	**---**	**19.5**
Cost of goods sold	**213.9**	**676.5**	**---**	**(22.0)**	**868.4**
Gross margin on revenues	**118.7**	**63.1**	**---**	**---**	**181.8**
Other operation and maintenance	**72.0**	**22.4**	**(4.1)**	**---**	**90.3**
Depreciation	**32.6**	**11.2**	**2.8**	**---**	**46.6**
Taxes other than income	**12.0**	**4.3**	**0.9**	**---**	**17.2**
Operating income	**2.1**	**25.2**	**0.4**	**---**	**27.7**
Other income	**0.3**	**5.7**	**0.1**	**---**	**6.1**
Other expense	**(0.7)**	**(1.7)**	**(0.5)**	**---**	**(2.9)**
Interest income	**---**	**0.3**	**4.8**	**(4.9)**	**0.2**
Interest expense	**(9.9)**	**(10.1)**	**(9.8)**	**4.9**	**(24.9)**
Income tax expense (benefit)	**(4.9)**	**9.3**	**(2.5)**	**---**	**1.9**
Income (loss) from continuing operations	**$ (3.3)**	**$ 10.1**	**$ (2.5)**	**$ ---**	**$ 4.3**
Income from discontinued operations	**---**	**1.3**	**---**	**---**	**1.3**
Income (loss) before cumulative effect of change in accounting principle	**(3.3)**	**11.4**	**(2.5)**	**---**	**5.6**
Cumulative effect of change in accounting for energy trading contracts, net of tax	**---**	**(5.9)**	**---**	**---**	**(5.9)**
Net income (loss)	**$ (3.3)**	**$ 5.5**	**$ (2.5)**	**$ ---**	**$ (0.3)**

(A) Beginning with the first quarter of 2002, Natural Gas Pipeline's operations consisted of three related businesses: Transportation and Storage, Gathering and Processing and Marketing and Trading. The following table is supplemental Natural Gas Pipeline information.

Three Months Ended March 31, 2003	Transportation and Storage	Gathering and Processing	Marketing and Trading	Eliminations	Total
(In millions)					
Operating revenues	**$ 69.0**	**$ 141.5**	**$ 646.6**	**$ (117.5)**	**$ 739.6**
Operating income	**$ 8.7**	**$ 6.5**	**$ 10.0**	**$ ---**	**$ 25.2**

Three Months Ended March 31, 2002	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	$ 262.1	$ 323.3	$ ---	$ (9.6)	$ 575.8
Fuel	85.0	---	---	(9.1)	75.9
Purchased power	63.8	---	---	---	63.8
Gas and electricity purchased for resale	---	256.7	---	(0.5)	256.2
Natural gas purchases - other	---	17.8	---	---	17.8

Cost of goods sold	148.8	274.5	---	(9.6)	413.7
Gross margin on revenues	113.3	48.8	---	---	162.1
Other operation and maintenance	64.7	24.0	(3.6)	---	85.1
Depreciation	30.8	12.0	2.4	---	45.2
Taxes other than income	11.9	4.0	0.8	---	16.7
Operating income	5.9	8.8	0.4	---	15.1
Other income	0.2	0.5	0.1	---	0.8
Other expense	(0.7)	(0.6)	---	---	(1.3)
Interest income	0.4	0.4	4.7	(5.0)	0.5
Interest expense	(9.8)	(13.1)	(10.6)	5.0	(28.5)
Income tax benefit	(2.5)	(0.6)	(2.0)	---	(5.1)
Loss from continuing operations	$ (1.5)	$ (3.4)	$ (3.4)	$ ---	$ (8.3)
Income from discontinued operations	---	2.1	---	---	2.1
Net loss	$ (1.5)	$ (1.3)	$ (3.4)	$ ---	$ (6.2)

(A) Beginning with the first quarter of 2002, Natural Gas Pipeline's operations consisted of three related businesses: Transportation and Storage, Gathering and Processing and Marketing and Trading. The following table is supplemental Natural Gas Pipeline information.

Three Months Ended March 31, 2002	Transportation and Storage	Gathering and Processing	Marketing and Trading	Eliminations	Total
(In millions)					
Operating revenues	$ 117.0	$ 38.8	$ 250.6	$ (83.1)	$ 323.3
Operating income (loss)	$ 10.8	$ (2.1)	$ 0.1	$ ---	$ 8.8

13. Commitments and Contingencies

Except as set forth below, the circumstances set forth in Note 15 to the Company’s consolidated financial statements included in the Company’s Form 10-K for the year ended December 31, 2002, appropriately represent, in all material respects, the current status of any material commitments and contingent liabilities.

Farmland Industries

Farmland Industries, Inc. (“Farmland”) voluntarily filed for Chapter 11 bankruptcy protection from creditors on May 31, 2002. Enogex provided gas transportation and supply services to Farmland, and is an unsecured creditor of Farmland. Enogex filed its Proof of Claim on January 7, 2003, for approximately $5.4 million. In April 2003, Enogex negotiated a settlement in which it will receive approximately $1.9 million in May 2003 which is approximately $0.3 million higher than the $1.6 million outstanding balance due (net of the $3.8 million reserve recorded in 2002).

Guarantees

During the normal course of business, Enogex issues guarantees on behalf of its subsidiaries for the purpose of securing credit for certain business activities. These guarantees are for payment when due of amounts payable by its subsidiaries under various agreements with counterparties. At March 31, 2003, accounts payable supported by guarantees was approximately $91.4 million. Since these guarantees by Enogex represent security for payment of payables obtained in the normal course of its subsidiaries business activities, the Company, on a consolidated basis, does not assume any additional liability as a result of this arrangement.

OGE Energy Corp. has issued a $5.0 million guarantee on behalf of OERI and a $15.0 million guarantee on behalf of Enogex Inc. for the purpose of securing credit for certain business activities. These guarantees are for payment when due of amounts payable by OERI and Enogex Inc. under various agreements with counterparties. At March 31, 2003, accounts payable supported by guarantees was approximately $0.1 million. Since these guarantees by OGE Energy Corp. represent security for payment of payables obtained in OERI’s and Enogex Inc.’s business activities, the Company, on a consolidated basis, does not assume any additional liability as a result of this arrangement.

As of December 31, 2002, in the event Moody’s or Standard & Poor’s were to lower Enogex’s senior unsecured debt rating to a below investment grade rating, Enogex would be required to post less than $5.0 million of collateral to satisfy its obligation under its financial and physical contracts.

Other

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies. Management consults with counsel and other appropriate experts to assess the claim. If in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's condensed consolidated financial statements. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of other currently

pending or threatened lawsuits and claims will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

14. Rate Matters and Regulation

Regulation and Rates

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

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

On October 11, 2002, OG&E, the OCC Staff, the Oklahoma Attorney General and other interested parties agreed to a settlement (the "Settlement Agreement") of OG&E's rate case. The administrative law judge subsequently recommended approval of the Settlement Agreement and on November 22, 2002, the OCC signed a rate order containing the provisions of the Settlement Agreement. The Settlement Agreement provides for, among other items: (i) a $25.0 million annual reduction in the electric rates of OG&E's Oklahoma customers which went into effect January 6, 2003; (ii) recovery by OG&E, through rate base, of the capital expenditures associated with the January 2002 ice storm; (iii) recovery by OG&E, over three years, of the $5.4 million in deferred operating costs, associated with the January 2002 ice storm, through OG&E's rider for sales to other utilities and power marketers; (iv) OG&E to acquire electric generating capacity of not less than 400 megawatts to be integrated into OG&E's generation system. Key portions of the Settlement Agreement are described in detail in Note 16 to the Company's Consolidated Financial Statements included in the Company's Form 10-K for the year ended December 31, 2002.

As part of the Settlement Agreement, OG&E also agreed to consider competitive bidding for gas transportation service to its natural gas fired generation facilities pursuant to the terms set forth in the Settlement Agreement. On April 29, 2003, OG&E filed an application with the OCC in which OG&E advised the OCC that after careful consideration competitive bidding for gas transportation was rejected in favor of a new intrastate firm no-notice load following gas transportation and storage services agreement with Enogex. This seven-year agreement provides for gas transportation and storage services for each of OG&E's natural gas fired generation plants. An OCC order in the case is expected during 2003.

Security Enhancements

On August 14, 2002, OG&E filed a report with the OCC outlining proposed expenditures and related actions for security enhancement. Attempting to make security investments at the proper level, OG&E has developed a set of guidelines intended to minimize long-term or widespread outages, minimize the impact on critical national defense and related customers, maximize the ability to respond to and recover from an attack, minimize the financial impact on OG&E that might be caused by an attack and accomplish these efforts with minimal impact on ratepayers. The OCC Staff has retained a security expert to review the report filed by OG&E, and a hearing is expected to be held in July 2003.

Other Regulatory Actions

The Settlement Agreement, when it became effective, provided for the termination of the Acquisition Premium Credit Rider ("APC Rider") and the Gas Transportation Adjustment Credit Rider ("GTAC Rider").

The APC Rider was approved by the OCC in March 2000 and was implemented by OG&E to reflect the completion of the recovery of the amortization premium paid by OG&E when it acquired Enogex in 1986. The effect of the APC Rider was to remove approximately $10.7 million annually from the amount being recovered by OG&E from its Oklahoma customers in current rates.

In June 2001, the OCC approved a stipulation (the "Stipulation") to the competitive bid process of OG&E's gas transportation service from Enogex. The Stipulation directed OG&E to reduce its rates to its Oklahoma retail customers by approximately $2.7 million per year through the implementation of the GTAC Rider. The GTAC Rider was a credit for gas transportation cost recovery and was applicable to and became part of each Oklahoma retail rate schedule to which OG&E's automatic fuel adjustment clause applies. As discussed above, the Settlement Agreement terminated the GTAC Rider. Consequently, these charges for gas transportation provided by Enogex are now included in base rates.

OG&E's Generation Efficiency Performance Rider ("GEP Rider") expired in June 2002. The GEP Rider was established initially in 1997 in connection with OG&E's 1996 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. In June 2000 the OCC made modifications to the GEP Rider which 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.

FERC Section 311 Rate Case

In December 2001, Enogex made its filing at the FERC under Section 311 of the Natural Gas Policy Act to establish rates and a treating fee and to address various other issues for the combined Enogex and Transok L.L.C. pipeline systems, effective January 1, 2002, the date that these systems began operating as a single Enogex pipeline system. The FERC Staff, Enogex and the active intervening parties held extensive settlement discussions. Enogex negotiated a settlement of the case with the interveners and, on March 5, 2003, filed a Stipulation and Agreement of Settlement and related documents with the FERC to resolve all issues in dispute in Docket No. PR02-10-000. FERC regulations provide for initial and reply comments. The only initial comments on the settlement, filed March 25, 2003, strongly supported the Stipulation. The proposed settlement includes a fee for processing to bring gas gathered behind processing plants to pipeline gas quality Btu standards (default processing fee) and a monthly low flow meter charge of $200 (offset in any month by the transportation revenues generated by gas through the meter). At December 31, 2002, the Company has fully reserved any treating fees billed through December 31, 2002. During the first quarter of 2003, the Company accrued approximately $1.8 million of treating fees and approximately $0.1 million of low flow meter charges. By Order dated May 9, 2003, the FERC accepted the settlement agreement and entered its order modifying Enogex's Statement of Operating Conditions ("SOC"). The FERC Order requires Enogex to modify its SOC within 15 days to eliminate the priority for scheduling and curtailment purposes for interruptible dedicated gas customers. With the dedicated gas priority eliminated, interruptible capacity will be allocated based on price, consistent with the FERC policy.

State Restructuring Initiatives

Oklahoma

As previously reported, the Electric Restructuring Act of 1997 (the "1997 Act") was designed to provide retail customers in Oklahoma a choice of their electric supplier by July 1, 2002. Additional implementing legislation was to be adopted by the Oklahoma Legislature to address many specific issues associated with the 1997 Act and with deregulation. In May 2000, a bill addressing the specific issues of deregulation was passed in the Oklahoma State Senate and then was defeated in the Oklahoma House of Representatives. 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, 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. In the current legislative session, Senate Bill 383 has been recently introduced to repeal the 1997 Act. It is unknown at this time whether the bill will be passed into law. The Company will continue to actively participate in the legislative process and expects to remain a competitive supplier of

electricity. As a result of the failures of California's attempt to deregulate its electricity markets, the Enron bankruptcy, and associated impacts on the industry, efforts to restructure the electricity market in Oklahoma appear at this time to be delayed indefinitely.

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 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. In March 2003, the Restructuring Law was repealed. As part of the repeal legislation, electric public utilities are permitted to recover transition costs. OG&E incurred approximately $2.4 million in transition costs necessary to carry out the Company's responsibilities associated with efforts to implement retail open access. The Company will be filing an application with the APSC in the next several months to recover these costs. The APSC will most likely schedule a hearing later in 2003.

15. Fair Value of Financial Instruments

The following information is provided regarding the estimated fair value of the Company's financial instruments, including derivative contracts related to the Company's price risk management activities that have significantly changed since December 31, 2002:

(In millions)	March 31, 2003 Carrying Amount	March 31, 2003 Fair Value	December 31, 2002 Carrying Amount	December 31, 2002 Fair Value
Price Risk Management Assets				
Energy Trading Contracts................	**$ 48.6**	**$ 48.6**	$ 21.4	$ 21.4
Price Risk Management Liabilities				
Energy Trading Contracts................	**$ 37.6**	**$ 37.6**	$ 14.6	$ 14.6

The carrying value of the financial instruments on the accompanying Condensed Consolidated Balance Sheets not otherwise discussed above approximates fair value. The valuation of the Company's energy trading contracts was determined primarily based on quoted market prices. However, in certain instances where market quotes are not available, other valuation techniques or models are used to estimate market values. The valuation of instruments also considers the credit risk of the counterparties and the potential impact of liquidating the position in an orderly manner over a reasonable period of time.

16. Subsequent Events

S-3 Filings

On April 2, 2003, the Company filed a Form S-3 Registration Statement to register 7,000,000 shares of the Company's common stock pursuant to the Company's Automatic Dividend Reinvestment and Stock Purchase Plan. Under the terms of this plan, the Company may accept requests for optional investments in amounts greater than $0.1 million per year and may offer a discount of up to three percent from current market prices. On April 30, 2003, the Company issued 288,133 shares of its common stock at a discount of 1.75 percent pursuant to the Company's Automatic Dividend Reinvestment and Stock Purchase Plan.

On April 15, 2003, the Company filed a Form S-3 Registration Statement pursuant to which it may offer from time to time up to $130.0 million of unsecured debt securities or shares of the Company's common stock.

On April 17, 2003, OG&E filed a Form S-3 Registration Statement pursuant to which it may offer from time to time up to $200.0 million aggregate principal amount of OG&E's unsecured senior notes.

Liquidity

On April 6, 2003, the Company renewed its $15.0 million line of credit facility for an additional one-year term expiring April 6, 2004.

Long-Term Debt

On April 29, 2003, $2.0 million of Enogex's long-term debt matured. On April 28, 2003, Enogex redeemed $10.0 million principal amount of 7.75 percent medium-term notes due April 24, 2023 and April 26, 2023.

Storm Damage

On May 8 and May 9, 2003, the Oklahoma City area was hit by a series of tornadoes that inflicted damage to OG&E's transmission and distribution system. The estimated storm damage costs are not expected to have a material effect on the Company's consolidated financial position or results of operations.

Regulatory Matters

On May 12, 2003, OG&E filed with the OCC a notice of intent to seek an annual increase in its rates to its Oklahoma customers of more than one percent. The notice lists the following, among others, as major issues to be addressed in its application: (i) the acquisition of a generation facility in accordance with the Settlement Agreement; (ii) increased capital expenditures for efficiency improvements and reliability enhancements to ensure fuel costs are

minimized, and (iii) increased pension, medical and insurance costs. OG&E expects to file its application for this rate increase on or before June 27, 2003, which filing will disclose the precise amount of the rate increase being sought.

Agreement with Colorado Interstate Gas Company

In December 2002, Enogex entered into an agreement with Colorado Interstate Gas Company ("CIG") regarding reservation of capacity on a proposed interstate gas pipeline (the "Cheyenne Plains Pipeline"). If completed, the Cheyenne Plains Pipeline would provide interstate gas transportation services in the states of Wyoming, Colorado and Kansas. Under the agreement, Enogex bid to reserve 60,000 Decatherms/day of capacity on the proposed pipeline. Such reservation would result in Enogex having access to significant additional natural gas supplies in the areas to be served by the proposed pipeline. CIG has advised that its plan is to request

FERC approval for construction of the pipeline in May 2003. Subject to regulatory and other approvals, CIG is proposing an in-service date of August 31, 2005. See a copy of this agreement attached as Exhibit 10.02.

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

Introduction

OGE Energy Corp. (collectively with its subsidiaries, the “Company”) is an energy and energy services provider offering physical delivery and management of both electricity and natural gas in the south central United States. The Company conducts these activities through two business segments, the Electric Utility and the Natural Gas Pipeline segments.

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

The Natural Gas Pipeline segment is conducted through Enogex Inc. and its subsidiaries (“Enogex”) and consists of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing and trading of natural gas (collectively, the “pipeline businesses”). The vast majority of Enogex’s natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. Through a 75 percent interest in the NOARK Pipeline System Limited Partnership, Enogex also owns a controlling interest in and operates the Ozark Gas Transmission System (“Ozark”), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. Enogex’s marketing and trading activities include corporate price risk management and other optimization services. Enogex was previously engaged in the exploration and production of natural gas, however, this portion of Enogex’s business, along with interests in certain gas gathering and processing assets in Texas, were sold in 2002 and in the first quarter of 2003 and are reported in the condensed consolidated financial statements as discontinued operations.

Company Strategy

In early 2002, the Company completed a review of its business strategy that was largely driven by the anticipated deregulation of the retail electric markets in Oklahoma and Arkansas. Due to a variety of factors, including the current efforts to repeal the Oklahoma Electric Restructuring Act of 1997 and the recent repeal of the Restructuring Law in Arkansas, the Company does not anticipate that deregulation of the electricity markets in Oklahoma or Arkansas will occur in the foreseeable future. The strategic direction of the Company has been revised to reflect these developments. As a result, the Company expects potentially slower earnings growth than associated with deregulation but with less variability of those earnings.

The Company’s business strategy will utilize the diversified asset position of OG&E and Enogex to provide energy products and services to customers primarily in the south central United States. The Company will focus on those products and services with limited or manageable commodity exposure. The Company intends for OG&E to continue as an integrated utility engaged in the generation and the distribution of electricity and to represent over time approximately 70 percent of the Company’s consolidated assets. The remainder of the Company’s assets will be in Enogex’s pipeline businesses. In addition to the incremental growth opportunities that Enogex provides, the Company believes that Enogex’s risk management capabilities, commercial skills and market information provide value to all of the Company’s businesses. Federal regulation in regard to the operations of the wholesale power market may change with the proposed Standard Market Design initiative at the FERC. In addition, Oklahoma and Arkansas legislatures and utility commissions may propose changes from time to time that could subject the utilities to market risk. Accordingly, the Company is applying risk management practices to all of its operations in an effort to mitigate the potential adverse effect of any future regulatory changes.

In the near term, OG&E plans on increasing its investment and growing earnings largely through the acquisition of a merchant power plant. As part of the OCC’s rate order on November 20, 2002, OG&E is seeking to purchase an electric power plant with at least 400 megawatts (“MW”) of generating capacity and to include the cost of such plant in its rate base. Given the surplus power in the region, the Company believes there is a continuing opportunity to purchase existing power plants at prices below the cost to build. This should enable OG&E to generate electricity for its customers at prices below those being paid by OG&E under existing qualified cogeneration and small power production producers’ contracts (“QF contracts”). Unless extended by OG&E, many of these QF contracts will expire over the next one to five years. Accordingly, OG&E will continue to explore opportunities to purchase power plants in order to serve its native load. OG&E anticipates filing with appropriate regulatory agencies to increase base rates to recover its investment in any power plant acquired and expects that customers should realize overall lower rates through fuel savings due to the increased efficiency of these new plants and lower capital costs than those associated with the expiring QF contracts.

Enogex initiated a program in 2002 to improve its financial performance. As a part of this performance improvement program, Enogex has received net sales proceeds of approximately $101.3 million from asset sales, reduced debt by 17 percent, reduced its number of employees by 12 percent and reorganized its operations. In addition to improving its earnings, Enogex will continue to take actions to reduce its exposure to commodity prices by, among other things, mitigating its exposure to keep whole processing arrangements and reducing earnings volatility. While the Company believes substantial progress has been achieved, substantial opportunities remain. Enogex expects to continue reviewing its work processes, rationalizing assets, renegotiating contracts to improve pricing on existing volumes and reducing costs to further improve its financial return in addition to pursuing opportunities for organic growth.

In 2003, in addition to these ongoing efforts, a major upgrade of the information systems is expected to be substantially completed. The Company believes that these upgrades will be a major step towards obtaining the data required for it to optimize its system, provide improved

customer service and enable management to more accurately determine the earnings potential of the unregulated pipeline system. The Company does not anticipate significantly increasing its investment in Enogex in accordance with the goal of targeting its pipeline businesses at 30 percent of the Company's consolidated assets.

Forward-Looking Statements

Except for the historical statements contained herein, the matters discussed in the following discussion and analysis, including the discussion in "2003 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", "expect", "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; changes in accounting standards, rules or guidelines; creditworthiness of suppliers, customers, and other contractual parties; actions by ratings agencies; and the other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission, including Exhibit 99.01 to the Company's Form 10-K for the year ended December 31, 2002.

Overview

General

The following discussion and analysis presents factors which affected the Company's consolidated results of operations for the three months ended March 31, 2003 as compared to the same period in 2002 and the Company's consolidated financial position at March 31, 2003. The following information should be read in conjunction with the Condensed Consolidated Financial Statements and Notes thereto and the Company's Form 10-K for the year ended December 31, 2002. Known trends and contingencies of a material nature are discussed to the extent considered relevant.

Enogex previously was engaged in the exploration and production of natural gas (the "E&P business"). Since January 1, 2002, Enogex has sold all of its E&P business along with certain gas gathering and processing assets that were owned by Enogex through its interest in the NuStar Joint Venture ("NuStar") and its interest in Belvan Corp., Belvan Limited Partnership and Todd Ranch Limited Partnership ("Belvan"). As required by accounting principles generally accepted in the United States, these dispositions have been reported as discontinued operations for the three months ended March 31, 2003 and 2002 in the condensed consolidated financial statements.

Operating Results

The Company reported approximately break-even results for the three months ended March 31, 2003 as compared to a loss of $0.08 per share for the same period in 2002. The improvement in financial performance was primarily due to better operating performance resulting from improved gross margins on revenues ("gross margin") in all of Enogex's businesses and lower interest expenses at the holding company partially offset by lower earnings at OG&E. The Company's results for the three months ended March 31, 2003 and 2002 include a contribution of $0.02 per share and $0.03 per share, respectively, from the discontinued operations discussed above. See "Enogex - - Discontinued Operations" for a further discussion.

OG&E posted a loss of $0.04 per share for the three months ended March 31, 2003 compared to a loss of $0.02 per share for the same period in 2002. OG&E's decrease was primarily attributable to lower electric rates and higher operating and maintenance expenses partially offset by increased revenue from customer growth and colder weather.

Enogex's operations, including discontinued operations, contributed $0.07 per share for the three months ended March 31, 2003 compared to a loss of $0.02 per share for the same period in 2002. Enogex's improvement was primarily attributable to better operating performance resulting from improved gross margins in all of Enogex's businesses, gains from asset sales, lower net interest expense and lower operating and maintenance expenses.

As stated above, Enogex's E&P business, its interest in NuStar and its interest in Belvan have been reported as discontinued operations for the three months ended March 31, 2003 and 2002 in the condensed consolidated financial statements as these assets have been sold. Earnings from discontinued operations were $0.02 per share for the three months ended March 31, 2003 compared to $0.03 per share for the same period in 2002. This decrease was attributable to the sale of Enogex's E&P business, NuStar and Belvan during 2002 and in the first quarter of 2003. See "Enogex - Discontinued Operations" for a further discussion.

The results of the holding company reflect a loss of $0.03 per share for the three months ended March 31, 2003 compared to a loss of $0.04 per share for the same period in 2002 primarily due to lower interest expenses.

Regulatory Considerations

On October 11, 2002, OG&E, the OCC Staff, the Oklahoma Attorney General and other interested parties agreed to a settlement (the "Settlement Agreement") of OG&E's rate case. The administrative law judge subsequently recommended approval of the Settlement Agreement and on November 22, 2002, the OCC signed a rate order containing the provisions of the Settlement Agreement. The Settlement Agreement provides for, among other items: (i) a $25.0 million annual reduction in the electric rates of OG&E's Oklahoma customers which went into effect January 6, 2003; (ii) recovery by OG&E, through rate base, of the capital expenditures associated with the January 2002 ice storm; (iii) recovery by OG&E, over three years, of the $5.4 million in deferred operating costs, associated with the January 2002 ice storm, through

OG&E's rider for sales to other utilities and power marketers ("off-system sales"); (iv) OG&E to acquire electric generating capacity ("New Generation") of not less than 400 MW's to be integrated into OG&E's generation system.

OG&E expects that the New Generation will provide savings, over a three-year period, in excess of $75 million. If OG&E is unable to demonstrate at least $75 million in savings, OG&E will be required to credit to its Oklahoma customers any unrealized savings below $75 million. In the event OG&E does not acquire the New Generation by December 31, 2003, OG&E will be required to credit $25.0 million annually (at a rate of 1/12 of $25.0 million per month for each month that the New Generation is not in place) to its Oklahoma customers beginning January 1, 2004 and continuing through December 31, 2006. However, if OG&E purchases the New Generation subsequent to January 2004, the credit to Oklahoma customers will terminate in the first month that the New Generation begins initial operations and any credited amount to Oklahoma customers will be included in the determination of the $75.0 million targeted savings. Reference is made to Note 14 of Notes to Condensed Consolidated Financial Statements in this report and to Note 16 to the Company's Consolidated Financial Statements included in the Company's Form 10-K for the year ended December 31, 2002 for a further discussion of the Settlement Agreement and of other recent actions relating to OG&E's rates.

On May 12, 2003, OG&E filed with the OCC a notice of intent to seek an annual increase in its rates to its Oklahoma customers of more than one percent. The notice lists the following, among others, as major issues to be addressed in its application: (i) the acquisition of a generation facility in accordance with the Settlement Agreement; (ii) increased capital expenditures for efficiency improvements and reliability enhancements to ensure fuel costs are minimized, and (iii) increased pension, medical and issuance costs. OG&E expects to file its application for this rate increase on or before June 27, 2003, which filing will disclose the precise amount of the rate increase being sought.

OG&E has been and will continue to be affected by competitive changes to the utility industry. Significant changes already have occurred and additional changes are being proposed to the wholesale electric market. Although it appears unlikely in the near future that changes will occur to retail regulation in the states served by OG&E due to the significant problems faced by California in its electric deregulation efforts and other factors, significant changes are possible, which could significantly change the manner in which OG&E conducts its business. These developments at the federal and state levels are described in more detail below under "Electric Competition; Regulation."

2003 Outlook

General

The Company currently expects that earnings in 2003 will be between $1.35 and $1.45 per share, assuming, among other things, normal weather and continued customer growth in the electric utility service area and improved performance at Enogex. The Company anticipates a contribution of approximately $112 to $118 million from OG&E, approximately $16 to $18

million from Enogex and a loss of approximately $14 million at the holding company. Enogex's 2003 earnings expectations have been increased due to favorable changes in the transportation and storage business. These changes include additional fuel recoveries, anticipated results of a new transportation and storage services agreement with OG&E and the favorable outcome of a customer bankruptcy case.

The Company has assumed approximately 83.5 million average common shares outstanding for 2003, up from approximately a 78.1 million average in 2002. The Company plans to issue a combination of equity and debt in 2003 to support the capital structure at OG&E for its purchase of generation and for other corporate purposes including the repayment of short-term debt. During April 2003, the Company filed two registration statements to register shares of the Company's common stock pursuant to the Company's Automatic Dividend Reinvestment and Stock Purchase Plan and to offer from time to time up to $130.0 million of unsecured debt securities or shares of the Company's common stock. Also, during April 2003, OG&E filed a registration statement to offer from time to time up to $200.0 million aggregate principal amount of OG&E's unsecured senior notes.

Dividend Policy

The Company's dividend policy is determined by the Board of Directors and is based on numerous factors, including management's estimate of the long-term earnings power of its businesses. The target payout ratio for the Company is to pay out as dividends approximately 75 percent of its earnings on an annual basis. The target payout ratio has been determined after consideration of numerous factors, including the largely retail composition of our shareholder base, our financial position, our growth targets, the composition of our assets and investment opportunities. On an operating basis excluding impairment charges, the Company's earnings per share for 2002 exceeded the dividend rate of $1.33 per share. While the dividend payout ratio is expected to exceed the target payout ratio in 2003, management after considering estimates of future earnings and numerous other factors, expects at this time that it will continue to recommend to the Board of Directors a continuance of the current dividend rate.

Asset Disposals

Enogex sold its interest in NuStar for approximately $37.0 million in February 2003. The Company recognized approximately a $1.4 million after tax gain in the first quarter of 2003 related to the sale of these assets, which is recorded in Income from Discontinued Operations in the accompanying Condensed Consolidated Statements of Operations. These assets were part of the Natural Gas Pipeline segment.

Enogex sold approximately 29 miles of transmission lines of the Ozark pipeline located in Pittsburg and Latimer counties in Oklahoma for approximately $10.0 million in January 2003. The Company recognized approximately a $5.3 million pre-tax gain in the first quarter of 2003 related to the sale of these assets, which is recorded in Other Income in the accompanying Condensed Consolidated Statements of Operations. These assets were part of the Natural Gas Pipeline segment.

Results of Operations

	Three Months Ended March 31,	
(In millions, except per share data)	**2003**	2002
Operating income	**$ 27.7**	$ 15.1
Net loss	**$ (0.3)**	$ (6.2)
Basic average common shares outstanding	**78.7**	78.0
Diluted average common shares outstanding	**78.9**	78.0
Basic and diluted loss per average common share	**$ ---**	$ (0.08)
Dividends declared per share	**$0.3325**	$0.3325

In reviewing its consolidated operating results, the Company believes that it is appropriate to focus on operating income as reported in its Condensed Consolidated Statements of Operations. Operating income was approximately $27.7 million and $15.1 million for the three months ended March 31, 2003 and 2002, respectively. These amounts exclude the results of Enogex's E&P business, NuStar and Belvan, which as explained above, were sold in 2002 and in the first quarter of 2003 and which are reported as discontinued operations. See "Enogex - Discontinued Operations" below for a further discussion.

Operating Income by Business Segment

	Three Months Ended March 31,	
(In millions)	**2003**	2002
OG&E (Electric Utility)	**$ 2.1**	$ 5.9
Enogex (Natural Gas Pipeline) (A)	**25.2**	8.8
Other Operations	**0.4**	0.4
Consolidated operating income	**$ 27.7**	$ 15.1

(A) Excludes discontinued operations.

The following operating income analysis by business segment includes intercompany transactions that are eliminated in the condensed consolidated financial statements.

OG&E

	Three Months Ended March 31,	
(In millions)	**2003**	2002
Operating revenues	**$ 332.6**	$ 262.1
Fuel	**141.2**	85.0
Purchased power	**72.7**	63.8
Gross margin on revenues	**118.7**	113.3
Other operating expenses	**116.6**	107.4
Operating income	**$ 2.1**	$ 5.9

System sales - MWH (A)	**5.9**	5.6
Off-system sales - MWH	**---**	0.1
Total sales - MWH	**$ 5.9**	$ 5.7

(A) Megawatt-hour

OG&E's operating income for the three months ended March 31, 2003 decreased approximately $3.8 million or 64.4 percent as compared to the same period in 2002. The decrease in operating income was primarily attributable to lower electric rates and higher operating and maintenance expenses partially offset by increased revenue from customer growth and colder weather.

The gross margin was approximately $118.7 million for the three months ended March 31, 2003 as compared to approximately $113.3 million during the same period in 2002, an increase of approximately $5.4 million or 4.8 percent. Growth in OG&E's service territory increased the gross margin by approximately $5.2 million due to approximately a four percent increase in sales to OG&E's customers. Higher recoveries of fuel costs from Arkansas customers through that state's automatic fuel adjustment clause increased the gross margin by approximately $2.9 million. In Arkansas, recovery of fuel costs is subject to a bandwidth mechanism. If fuel costs are within the bandwidth range, recoveries are not adjusted on a monthly basis; rather they are reset annually on April 1. The gross margin increased approximately $1.5 million for the three months ended March 31, 2003 as compared to 2002 due to a loss of revenue in January 2002, associated with the interruption of service to our customers as a result of the severe January 2002 ice storm. The gross margin was also increased by approximately $1.0 million as a result of colder weather in 2003 in OG&E's service territory. Partially offsetting the increase in gross margin was a decrease of approximately $4.2 million due to lower electric rates resulting from OG&E's rate reduction, which went into effect on January 6, 2003. The loss of revenue associated with various rate riders also decreased gross margin by approximately $1.0 million.

Cost of goods sold for OG&E consists of fuel used in electric generation and purchased power. Fuel expense was approximately $141.2 million for the three months ended March 31, 2003 as compared to approximately $85.0 million during the same period in 2002, an increase of approximately $56.2 million or 66.1 percent. The increase was due primarily to an increase in the average cost of fuel per kilowatt-hour due to higher natural gas prices in the first quarter of 2003. Purchased power costs were approximately $72.7 million for the three months ended March 31, 2003 as compared to approximately $63.8 million during the same period in

2002, an increase of approximately $8.9 million or 13.9 percent. The increase was primarily due to a 19.2 percent increase in the volume of energy purchased in the first quarter of 2003.

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component included in the cost-of-service for ratemaking, are passed through to OG&E's customers through automatic fuel adjustment clauses. While the regulatory mechanisms for recovering fuel costs differ in Oklahoma and Arkansas, in both states the costs are passed through to customers and are intended to provide neither an ultimate benefit nor detriment to OG&E. The automatic fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC. The OCC, the APSC and the FERC have authority to review the appropriateness of gas transportation charges or other fees OG&E pays to Enogex.

Other operating expenses, consisting of operating and maintenance expense, depreciation expense and taxes other than income, were approximately $116.6 million for the three months ended March 31, 2003 as compared to approximately $107.4 million during the same period in 2002, an increase of approximately $9.2 million or 8.6 percent. OG&E's operating and maintenance expenses were approximately $72.0 million for the three months ended March 31, 2003 as compared to approximately $64.7 million during the same period in 2002, an increase of approximately $7.3 million or 11.3 percent. This increase was primarily due to approximately $5.4 million of operating and maintenance costs incurred during the first quarter of 2002 in connection with the severe January 2002 ice storm being reported as a regulatory asset. These 2002 expenditures, incurred by field service personnel, would normally have been charged to maintenance expenses. Also contributing to the increase in operating and maintenance expenses was an increase of approximately $2.3 million in contract labor, primarily related to the overhaul of one of OG&E's turbines. Pension and benefit expenses increased approximately $2.0 million for the three months ended March 31, 2003 as compared to the same period in 2002 due to the general upward trend in these costs. These increases were partially offset by lower levels of uncollectibles expense of approximately $1.2 million and lower levels of overtime of approximately $1.1 million for the three months ended March 31, 2003 as compared to the same period in 2002.

Depreciation expense was approximately $32.6 million for the three months ended March 31, 2003 as compared to approximately $30.8 million during the same period in 2002, an increase of approximately $1.8 million or 5.8 percent. The increase was due to the amortization of the regulatory asset associated with the January 2002 ice storm as set forth in the Settlement Agreement. See Note 14 of Notes to Condensed Consolidated Financial Statements. Taxes other than income were approximately $12.0 million for the three months ended March 31, 2003 as compared to approximately $11.9 million during the same period in 2002, an increase of approximately $0.1 million or 0.8 percent. This increase was due to higher ad valorem tax accruals.

Enogex - Continuing Operations

	Three Months Ended March 31,	
(Dollars in millions)	**2003**	2002

Operating revenues	**$ 739.6**	$ 323.3
Gas and electricity purchased for resale	**657.0**	256.7
natural gas purchases - other	**19.5**	17.8
Gross margin on revenues	**63.1**	48.8
Other operating expenses	**37.9**	40.0
Operating income	**$ 25.2**	$ 8.8
Physical system supply - MMcfd (A)	**1,617**	1,696
Natural gas processed - MMcfd	**424**	526
Natural gas liquids sold - million gallons	**59.0**	74.9
Average sales price per gallon	**$ 0.660**	$ 0.353
Natural gas marketed - Bbtu (B)	**108,296**	98,300
Average sales price per Bbtu	**$ 5.938**	$ 2.593
Power marketed - MWH	**60,388**	266,913
Average sales price per MWH	**$ 45.810**	$ 26.310

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

Enogex's operating income for the three months ended March 31, 2003 increased approximately $16.4 million or 186.4 percent as compared to the same period in 2002. The increase was primarily attributable to better operating performance resulting from improved gross margins in all of Enogex's businesses and lower overall expenses. Enogex sold its E&P business and its interest in Belvan during 2002 and Enogex sold its interest in NuStar during the first quarter of 2003; accordingly, these are reported as discontinued operations for the three months ended March 31, 2003 and 2002 in the condensed consolidated financial statements. See "Enogex - Discontinued Operations" below for a further discussion.

Transportation and storage contributed approximately $27.7 million of Enogex's gross margin for the three months ended March 31, 2003 as compared to approximately $26.3 million during the same period in 2002, an increase of approximately $1.4 million or 5.3 percent. Gross margins benefited from increased demand fees of approximately $2.9 million during the three months ended March 31, 2003 as compared to the same period in 2002 due to higher demand fees related to the recently acquired Stuart Storage Facility and higher demand fees from Enogex's marketing and trading business. Also contributing to the improvement was increased interruptible transportation on Ozark of approximately $1.0 million due to higher volumes and prices during the three months ended March 31, 2003 as compared to the same period in 2002. These increases were partially offset by decreased firm transportation revenue of approximately $2.4 million during the three months ended March 31, 2003 as compared to the same period in 2002, primarily the result of contract revisions and expirations. The decrease associated with contract revisions is due to the timing and amount of fuel recoveries previously included in firm transportation revenue during the three months ended March 31, 2002. Also contributing to the decreased firm transportation revenue were reductions in contractual payments in the first and

fourth quarters, which will be made up by increases in contractual payments in the second and third quarters.

Gathering and processing contributed approximately $22.1 million of Enogex's gross margin for the three months ended March 31, 2003 as compared to approximately $17.3 million during the same period in 2002, an increase of approximately $4.8 million or 27.7 percent. Gross margins benefited from treating fees of approximately $1.8 million during the three months ended March 31, 2003 as compared to the same period in 2002 and the true-up of a prior period accrual of approximately $1.8 million. Although processing volumes were down, the average realized prices increased. The average gross margin per gallon of natural gas liquids was $0.138 during the three months ended March 31, 2003 as compared to $0.071 during the same period in 2002. Also contributing to the increase was approximately a $0.9 million increase in the gathering gross margin due to increased volumes of 18 percent primarily reflecting the impact of reduced volumes in 2002 as a result of the severe January 2002 ice storm.

Marketing and trading contributed approximately $13.3 million of Enogex's gross margin for the three months ended March 31, 2003 as compared to approximately $5.2 million during the same period in 2002, an increase of approximately $8.1 million. Gross margins included approximately $10.2 million from gains on the sale of natural gas in storage during the first quarter of 2003. These gains were largely offset by Enogex recording a $9.0 million pre-tax loss, in the nature of a cumulative effect of a change in accounting principle in the first quarter of 2003 as a result of accounting for certain energy contracts and natural gas in storage at the lower of cost or market rather than on a mark-to-market basis. See "Accounting Pronouncements" for a further discussion. During the three months ended March 31, 2002, gross margins included approximately $0.3 million from gains on the sale of natural gas in storage. Therefore, absent the impact of the change in accounting principle, gross margins would have been approximately $4.3 million during the three months ended March 31, 2003 as compared to approximately $5.2 million during the same period in 2002. This $0.9 million decrease in the gross margin was due primarily to a $1.2 million increase in demand fees paid to Enogex's transportation and storage business and approximately a $0.4 million decrease in the power sales gross margin, which was only partially offset by a higher gross margin from sales of natural gas in storage without regard to the change in accounting principle.

Other operating expenses, consisting of operating and maintenance expense, depreciation expense and taxes other than income, for Enogex were approximately $37.9 million for the three months ended March 31, 2003 as compared to approximately $40.0 million during the same period in 2002, a decrease of approximately $2.1 million or 5.3 percent. Operating and maintenance expenses were approximately $22.4 million for the three months ended March 31, 2003 as compared to approximately $24.0 million during the same period in 2002, a decrease of approximately $1.6 million or 6.7 percent. The decrease was primarily due to lower uncollectibles expense of approximately $0.8 million, lower payroll expenses of approximately $0.7 million and lower materials and supplies expense of approximately $0.6 million. These decreases were partially offset by higher employee benefit costs of approximately $0.9

million. Depreciation expense was approximately $11.2 million for the three months ended March 31, 2003 as compared to approximately $12.0 million during the same period in 2002, a

decrease of approximately $0.8 million or 6.7 percent. The decrease was primarily the result of ceasing depreciation on the natural gas processing plants written down in the fourth quarter of 2002. Taxes other than income was approximately $4.3 million for the three months ended March 31, 2003 as compared to approximately $4.0 million during the same period in 2002, an increase of approximately $0.3 million or 7.5 percent. The increase was the result of higher ad valorem tax accruals.

Enogex - Discontinued Operations

On March 25, 2002, Enogex entered into an Agreement of Sale and Purchase with West Texas Gas, Inc. to sell all of its interests in Belvan for approximately $9.8 million. The effective date of the sale was January 1, 2002 and the closing occurred on March 28, 2002. The Company recognized approximately a $1.6 million after tax gain related to the sale of these assets.

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

On November 14, 2002, Enogex entered into an Agreement of Sale and Purchase with Quicksilver Resources, Inc. to sell all of its exploration and production assets located in Michigan for approximately $32.0 million. The effective date of the sale was July 1, 2002 and the closing occurred on December 2, 2002. The Company recognized approximately a $2.9 million after tax gain related to the sale of these assets.

During the third quarter of 2002, the Company decided to sell all of its interests in NuStar. On January 23, 2003, Enogex entered into an Agreement of Sale and Purchase with Benedum Gas Partners, L.P. to sell all of the interests of its subsidiary, Enogex Products Corporation, in the west Texas properties consisting of NuStar, which has operations consisting of the extraction and sale of natural gas liquids, for approximately $37.0 million. The effective date of the sale was January 1, 2003 and the closing occurred on February 18, 2003. The Company recognized approximately a $1.4 million after tax gain in the first quarter of 2003 related to the sale of these assets, which is recorded in Income from Discontinued Operations in the accompanying Condensed Consolidated Statements of Operations.

As a result of these sale transactions, Enogex's E&P business, its interest in NuStar and its interest in Belvan, all of which were part of the Natural Gas Pipeline segment, have been reported as discontinued operations for the three months ended March 31, 2003 and 2002 in the condensed consolidated financial statements. Results for these discontinued operations are summarized and discussed below.

	Three Months Ended March 31,	
(In millions)	**2003**	2002
Operating revenues	**$ 7.8**	$ 19.4
Gas purchased for resale	**5.9**	11.8
Natural gas purchases - other	**0.6**	2.0
Gross margin on revenues	**1.3**	5.6
Other operating expenses	**1.4**	5.4
Operating income (loss)	**$ (0.1)**	$ 0.2

Gross margin was approximately $1.3 million for the three months ended March 31, 2003 as compared to approximately $5.6 million during the same period in 2002, a decrease of approximately $4.3 million or 76.8 percent. Other operating expenses were approximately $1.4 million for the three months ended March 31, 2003 as compared to approximately $5.4 million during the same period in 2002, a decrease of approximately $4.0 million or 74.1 percent. The decreases in the gross margin and other operating expenses were primarily attributable to the sale of Enogex's E&P business and Belvan during 2002 and the sale of NuStar in February 2003.

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

Other income includes, among other things, contract work performed by OG&E, non-operating rental income, gain on the sale of assets, profit on the retirement of fixed assets, minority interest income and miscellaneous non-operating income. Other income was approximately $6.1 million for the three months ended March 31, 2003 as compared to approximately $0.8 million during the same period in 2002, an increase of approximately $5.3 million. The increase was due to a pre-tax gain of approximately $5.3 million related to the sale of approximately 29 miles of transmission lines of the Ozark pipeline in January 2003.

Other expense includes, among other things, expenses from loss on the sale of assets, loss on retirement of fixed assets, minority interest expense, miscellaneous charitable donations, expenditures for certain civic, political and related activities and miscellaneous deductions. Other expense was approximately $2.9 million for the three months ended March 31, 2003 as compared to approximately $1.3 million during the same period in 2002, an increase of approximately $1.6 million. This increase was primarily due to an increase of approximately $1.1 million in minority interest expense related to the gain from the sale of approximately 29 miles of transmission lines of the Ozark pipeline in January 2003 that was attributable to the minority interest. Also contributing to the increase was approximately a $0.3 million increase in the liability associated with the deferred compensation plan.

Net interest expense includes interest income, interest expense and other interest charges. Net interest expense was approximately $24.7 million for the three months ended March 31, 2003 as compared to approximately $28.0 million during the same period in 2002, a decrease of approximately $3.3 million or 11.8 percent. This decrease was primarily due to a reduction in interest expense of approximately $2.6 million related to the retirement of $140.0 million of Enogex debt during 2002 and approximately a $0.6 million decrease in interest expense related to commercial paper activity.

Income tax expense was approximately $1.9 million for the three months ended March 31, 2003 as compared to an income tax benefit of approximately $5.1 million during the same period in 2002, an increase of approximately $7.0 million. The increase was primarily from higher pre-tax income at Enogex partially offset by a higher pre-tax loss at OG&E during the first quarter of 2003.

Financial Condition

The balance of Accounts Receivable, Net was approximately $376.8 million and $304.6 million at March 31, 2003 and December 31, 2002, respectively, an increase of approximately $72.2 million or 23.7 percent. The increase was primarily due to higher natural gas prices associated with Enogex's activities in the first quarter of 2003. This increase was offset by the increased cost of natural gas as discussed below regarding Accounts Payable.

The balance of Fuel Inventories was approximately $67.7 million and $99.7 million at March 31, 2003 and December 31, 2002, respectively, a decrease of approximately $32.0 million or 32.1 percent. The decrease was due to the inventory sales during the first quarter of 2003.

The balance of current Price Risk Management assets was approximately $45.3 million and $17.1 million at March 31, 2003 and December 31, 2002, respectively, an increase of approximately $28.2 million or 164.9 percent. The increase was due to significant volatility and higher natural gas prices associated with OERI's trading activities in the first quarter of 2003. This increase is partially offset by an increase in current Price Risk Management liabilities.

The balance of the Pipeline Imbalance asset was approximately $6.0 million and $34.3 million at March 31, 2003 and December 31, 2002, respectively, a decrease of approximately $28.3 million or 82.5 percent. The decrease was primarily due to scheduled gas receipts from other pipelines used by the Company to temporarily store gas as part of a previously negotiated agreement, commonly referred to as park and loan agreements.

The balance of Fuel Clause Under Recoveries was approximately $48.8 million and $14.7 million at March 31, 2003 and December 31, 2002, respectively, an increase of approximately $34.1 million or 232.0 percent. This increase was due to under recoveries from OG&E’s customers as OG&E’s cost of fuel exceeded the amount billed during the first quarter of 2003. The cost of fuel subject to recovery through the fuel clause mechanism was approximately $1.54 per million British thermal unit ("MMBtu") in December 2002, and was approximately $2.28 per MMBtu for the quarter ended March 31, 2003. The Company's fuel recovery clauses are

designed to smooth the impact of fuel price volatility on customers' bills. As a result the Company under recovers fuel cost in periods of rising prices and over recovers fuel cost when prices decline. Provisions in the fuel clauses allow the Company to amortize under or over recovery. The Company began amortizing the under collected amounts beginning with the April 2003 customers bills.

The balance of Short-Term Debt was approximately $173.0 million and $275.0 million at March 31, 2003 and December 31, 2002, respectively, a decrease of approximately $102.0 million or 37.1 percent. The decrease was primarily due to proceeds received from the sale of Ozark and NuStar and from the sale of natural gas inventory by Enogex during the first quarter of 2003, which were used to reduce the commercial paper balance at the holding company.

The balance of Accounts Payable was approximately $387.6 million and $254.1 million at March 31, 2003 and December 31, 2002, respectively, an increase of approximately $133.5 million or 52.5 percent. This increase was partially offset by the $72.2 million increase in Accounts Receivable, Net which was driven by higher natural gas prices associated with OG&E's and Enogex's activities in the first quarter of 2003. Also contributing to the increase in Accounts Payable was a $26.2 million increase in the cost of under recovered fuel in March 2003.

The balance of current Price Risk Management liabilities was approximately $35.9 million and $13.9 million at March 31, 2003 and December 31, 2002, respectively, an increase of approximately $22.0 million or 158.3 percent. The increase was due to significant volatility and higher natural gas prices associated with OERI's trading activities in the first quarter of 2003. This increase was offset by an increase in current Price Risk Management assets.

Liquidity and Capital Requirements

General

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, operating lease obligations, hedging activities, natural gas storage and delays in recovering unconditional purchase obligations. The Company generally meets its cash needs through a combination of internally generated funds, short-term borrowings and permanent financings.

Interest Rate Swap Agreements

At March 31, 2003 and December 31, 2002, the Company had three outstanding interest rate swap agreements: (i) OG&E entered into an interest rate swap agreement, effective March 30, 2001, to convert $110.0 million of 7.30 percent fixed rate debt due October 15, 2025, to a variable rate based on the three month London InterBank Offering Rate ("LIBOR") and (ii) Enogex entered into two separate interest rate swap agreements, effective July 15, 2002 and October 24, 2002, to convert $100.0 million each of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the six month LIBOR.

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

At March 31, 2003 and December 31, 2002, the fair values pursuant to the interest rate swaps were approximately $16.1 million and $15.9 million, respectively, and are included in non-current Price Risk Management assets in the accompanying Condensed Consolidated Balance Sheets. A corresponding net increase of approximately $16.1 million and $15.9 million is reflected in Long-Term Debt at March 31, 2003 and December 31, 2002, respectively, as these fair value hedges were effective at March 31, 2003 and December 31, 2002.

Future Capital Requirements

The Company's 2003 to 2005 construction program does not include the building of any additional generating units. Instead, in accordance with the Settlement Agreement approved by the OCC on November 20, 2002, OG&E intends to purchase an electric generating plant with at least 400 MW's of generating capacity. The Company believes that an efficient combined cycle plant can be purchased for a price less than the cost to build a new facility. To reliably meet the increased electricity needs of OG&E's customers during the foreseeable future, OG&E will continue to invest to maintain the integrity of the delivery system. Approximately $4.9 million of the Company's capital expenditures budgeted for 2003 are to comply with environmental laws and regulations.

Future financing requirements may be dependent, to varying degrees, upon numerous factors such as general economic conditions, abnormal weather, load growth, acquisitions of other businesses, actions by rating agencies, inflation, changes in environmental laws or regulations, rate increases or decreases allowed by regulatory agencies, new legislation and market entry of competing electric power generators.

Future Sources of Financing

General

Apart from the funds required to purchase at least 400 MW's of a power plant pursuant to the Settlement Agreement, management expects that internally generated funds will be adequate over the next three years to meet other anticipated capital expenditures, operating needs, payment of dividends and maturities of long-term debt.

Short-Term Debt

Short-term borrowings will be used to meet working capital requirements. The following table shows the Company's lines of credit in place at April 30, 2003. Short-term borrowings will consist of a combination of bank borrowings and commercial paper.

Lines of Credit *(In millions)*

Entity	Amount	Maturity
OGE Energy Corp. (A)	$ 200.0	January 8, 2004
	100.0	January 15, 2004
	15.0	April 6, 2004
OG&E	100.0	June 26, 2003
Total	$ 415.0	

(A) The lines of credit at OGE Energy Corp. are used to back up the Company's commercial paper borrowings, which were approximately $202.6 million at April 30, 2003. No borrowings were outstanding at April 30, 2003 under any of the lines of credit shown above.

The Company's ability to access the commercial paper market could be adversely impacted by a commercial paper ratings downgrade. The lines of credit contain ratings triggers that require annual fees and borrowing rates to increase if the Company suffers an adverse ratings impact. The impact of additional downgrades of the Company's rating 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. See "Security Ratings" for potential financing needs upon a downgrade by Moody's Investors Service ("Moody's") of Enogex's long-term debt rating.

Unlike the Company and Enogex, OG&E must obtain regulatory approval from the FERC in order to borrow on a short-term basis. OG&E has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time.

Security Ratings

On January 15, 2003, Standard & Poor's Ratings Services ("Standard & Poor's") lowered the credit ratings of OGE Energy Corp.'s, OG&E's and Enogex's senior unsecured debt from A- to BBB+. OGE Energy Corp.'s short-term commercial paper ratings were affirmed at A-2. The outlook is now stable. Standard & Poor's cited the relatively low-risk low-cost efficient operations of OG&E and the business and financial profile of Enogex, which has higher risk. Standard & Poor's further cited the rationalization at Enogex has resulted in a business-risk reduction, but it is not adequate to warrant an improvement in the overall business score. The Company may experience somewhat higher borrowing costs but does not expect the actions by Standard & Poor's to have a significant impact on the Company's consolidated financial position or results of operations.

On February 5, 2003, Moody's lowered the credit ratings of OGE Energy Corp.'s senior unsecured debt to Baa1 from A3, OG&E's senior unsecured debt to A2 from A1 and Enogex's senior unsecured debt to Baa3 from Baa2. OGE Energy Corp.'s short-term commercial paper rating was unchanged at P-2. The outlook for OGE Energy Corp. and OG&E is stable and Enogex is negative. Moody's cited the diminished credit profile of both OG&E and Enogex with OG&E having competitive generation and stable cash flow but with regulatory risk associated with the acquisition of at least 400 MW's of new generation and Enogex exposed to the seasonality of its gas processing business although it has reduced its keep-whole exposure. The Company may experience somewhat higher borrowing costs but does not expect the actions by

Moody's to have a significant impact on the Company's consolidated financial position or results of operations. As a result of Enogex's rating being lowered to Baa3, OGE Energy Corp. was required to issue a $5.0 million guarantee on Enogex's behalf for a counterparty. At March 31, 2003, there is no outstanding liability balance related to this guarantee. In the event one or more of the credit ratings were to fall below investment grade, Enogex may seek OGE Energy Corp. guarantees to satisfy its customers in order to avoid disruption of its marketing and trading business.

A security rating is not a recommendation to buy, sell or hold securities. Such rating may be subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

Asset Sales

Also contributing to the liquidity of the Company have been numerous asset sales by Enogex. Since January 1, 2002, completed sales generated net proceeds of approximately $101.3 million. Sales proceeds generated to date have been used to reduce debt at Enogex and commercial paper at the holding company.

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

Critical Accounting Policies and Estimates

The Condensed Consolidated Financial Statements and Notes to Condensed Consolidated Financial Statements included in this Form 10-Q and in the Company's Form 10-K for the year ended December 31, 2002 contain information that is pertinent to Management's Discussion and Analysis. In preparing these condensed consolidated financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the condensed consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the Company's condensed 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 are in the valuation of pension plan assumptions, impairment estimates, contingency reserves, unbilled revenue for OG&E, the allowance for uncollectible accounts receivable, the valuation of energy purchase and sale contracts and gas storage inventory. The selection, application and disclosure of the following critical accounting estimates have been discussed with the Company's audit committee.

Consolidated (including Electric Utility and Natural Gas Pipeline Segments)

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 13 of the Notes to Consolidated Financial Statements in the Company's Form 10-K for the year ended December 31, 2002.

The Company assesses potential impairments of assets when there is evidence that events or changes in circumstances indicate that an asset's carrying value may not be recoverable. An impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset.

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies. Management consults with counsel and other appropriate experts to assess the claim. If in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's condensed consolidated financial statements.

Electric Utility Segment

OG&E reads its customers' meters and sends bills to its customers 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. Unbilled revenue is presented in Accrued Unbilled Revenues on the Condensed Consolidated Balance Sheets and in Operating Revenues on the Condensed Consolidated Statements of Operations based on estimates of usage and prices during the period. At March 31, 2003 and December 31, 2002, Accrued Unbilled Revenues were approximately $32.5 million and $28.2 million, respectively. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

All customer balances are written off if not collected within six months after the account is finalized. 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 the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Condensed Consolidated Balance Sheets and is included in Other Operation and Maintenance Expense on the Condensed Consolidated

Statements of Operations. The allowance for uncollectible accounts receivable for OG&E was approximately $2.8 million and $4.7 million at March 31, 2003 and December 31, 2002, respectively.

Natural Gas Pipeline Segment

Operating revenues for transportation, gathering and storage services for Enogex are estimated each month based on the prior month's activity and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current month nominations and contracted prices. Operating revenues associated with the production of natural gas liquids are estimated based on current month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated operating revenues are reflected in Accounts Receivable on the Condensed Consolidated Balance Sheets and in Operating Revenues on the Condensed Consolidated Statements of Operations.

Estimates for gas purchases are based on sales volumes and contracted purchase prices. Estimated gas purchases are included in Accounts Payable on the Condensed Consolidated Balance Sheets and in Cost of Goods Sold on the Condensed Consolidated Statements of Operations.

In October 2002, the Emerging Issues Task Force ("EITF") reached a consensus to rescind EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities", as amended effective for fiscal periods beginning after December 15, 2002. Effective October 25, 2002, all new contracts and physical inventories that would have been accounted for under EITF 98-10 are no longer marked to market through earnings unless the contracts meet the definition of a derivative under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." Contracts and physical inventories that existed at October 25, 2002 continued to be accounted for under EITF 98-10 through December 31, 2002. Effective January 1, 2003, these contracts were revalued in accordance with provisions of EITF Issue No. 02-3, "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities," which rescinded EITF 98-10. The change in the value of these contracts is shown as a cumulative effect of a change in accounting principle in the accompanying Condensed Consolidated Statements of Operations. Energy contracts are entered into by OGE Energy Resources, Inc. ("OERI"), the marketing subsidiary of Enogex. Corporate risk management and credit committees charged with enforcing the trading and credit policies, which include specific guidance on counterparties, procedures, credit and trading limits, monitor these activities. Marketing activities include the trading and marketing of natural gas, electricity, and natural gas liquids. The vast majority of positions expire within two years, which is when the cash aspect of the transactions will be realized. In nearly all cases, independent market prices are obtained and compared to the values used for the mark-to-market valuation, and an oversight group outside of the marketing organization monitors all modeling methodologies and assumptions. The recorded value of the energy 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 risk policies. The Company utilizes a model to estimate the fair value of its energy contracts including derivatives that do not have an independent market price. Approximately 94.1 percent of the

Company's recorded fair value of energy contracts and gas in storage utilize quoted market prices in an active market. At March 31, 2003, unrealized mark-to-market gains were approximately $6.9 million, which included approximately $6.5 million based on independent market prices. Energy contracts are presented in Price Risk Management assets and liabilities on the Condensed Consolidated Balance Sheets and in Operating Revenues on the Condensed Consolidated Statements of Operations. See "Accounting Pronouncements" for a further discussion.

Effective January 1, 2003, gas storage inventory used in OERI's trading activities are accounted for at the lower of cost or market in accordance with the guidance in EITF 02-3, which resulted in the rescission of EITF 98-10. Prior to January 1, 2003, this inventory was accounted for on a fair value accounting basis utilizing a gas index that in management's opinion approximated the current market value of natural gas in that region as of the Balance Sheet date. In order to minimize risk, OERI may enter into contracts or hedging instruments to hedge the fair value of this inventory. If these contracts qualify for hedge accounting under SFAS No. 133, the hedged portion of the inventory is recorded at fair value with an offsetting gain or loss recorded currently in earnings. The fair value of the hedging instrument is also recorded on the books of the Company as a Price Risk Management asset or liability with an offsetting gain or loss recorded in current earnings. At March 31, 2003, the Company had no qualified fair value hedges under SFAS No. 133 for natural gas inventory. Natural gas inventories used in OERI's trading activities, which are valued at the lower of cost or market, were approximately $2.4 million at March 31, 2003. See "Accounting Pronouncements" for a further discussion. Gas storage inventory is presented in Fuel Inventories on the Condensed Consolidated Balance Sheets and in Cost of Goods Sold on the Condensed Consolidated Statements of Operations.

Customer balances are written off when the Company concludes the required payment of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable is established on a case-by-case basis when the Company believes the required payment of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Condensed Consolidated Balance Sheets and is included in Other Operation and Maintenance Expense on the Condensed Consolidated Statements of Operations. The allowance for uncollectible accounts receivable for the Natural Gas Pipeline segment was approximately $8.9 million at March 31, 2003 and December 31, 2002.

Accounting Pronouncements

In June 2001, the Financial Accounting Standards Board ("FASB") issued SFAS No. 143, "Accounting for Asset Retirement Obligations." SFAS No. 143 applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. SFAS No. 143 affects the Company's accrued plant removal costs for generation, transmission, distribution and processing facilities and requires that the fair value of a liability for an asset retirement obligation be

recognized in the period in which it is incurred if a reasonable estimate of the fair value can be made. If a reasonable estimate of the fair value cannot be made in the period the asset retirement obligation is incurred, the liability shall be recognized when a reasonable estimate of the fair value can be made. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes, written or oral contracts, including obligations arising under the doctrine of promissory estoppel. The recognition of an asset retirement obligation is capitalized as part of the carrying amount of the long-lived asset. Asset retirement obligations represent future liabilities and, as a result, accretion expense is accrued on this liability until such time as the obligation is satisfied. Adoption of SFAS No. 143 is required for financial statements issued for fiscal years beginning after June 15, 2002. The Company adopted this new standard effective January 1, 2003 and the adoption of this new standard did not have a material impact on its consolidated financial position or results of operations. In connection with the adoption of SFAS No. 143, the Company assessed whether it had a legal obligation within the scope of SFAS No. 143. The Company determined that it had a legal obligation to retire certain assets. As the Company currently has no plans to retire any of these assets and the remaining life is indeterminable, an asset retirement obligation was not recognized; however, the Company will monitor these assets and record a liability when a reasonable estimate of the fair value can be made. As described below, amounts recovered from ratepayers related to estimated asset retirement obligations recorded as a liability in Accumulated Depreciation were reclassified as a regulatory liability in the first quarter of 2003.

SFAS No. 143 also requires that, if the conditions of SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" are met, a regulatory asset or liability should be recorded to recognize differences between asset retirement costs recorded under SFAS No. 143 and legal or other asset retirement costs recognized for ratemaking purposes. Upon adoption of SFAS No. 143, the Company was required to quantify the amount of asset retirement costs previously recovered from ratepayers for other than legal obligations and reclassify those differences as regulatory assets or liabilities. At December 31, 2002, approximately $109.3 million had been previously recovered from ratepayers and recorded as a liability in Accumulated Depreciation related to estimated asset retirement obligations. This balance was reclassified as a regulatory liability on the December 31, 2002 Condensed Consolidated Balance Sheet.

In July 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities." SFAS No. 146 addresses financial accounting and reporting for costs associated with exit and disposal activities and supersedes EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)." SFAS No. 146 requires recognition of a liability for a cost associated with an exit or disposal activity when the liability is incurred, as opposed to when the entity commits to an exit plan under EITF 94-3. SFAS No. 146 also establishes that the liability should initially be measured and recorded at fair value. Adoption of SFAS No. 146 is required for exit and disposal activities initiated after December 31, 2002. The Company adopted this new standard effective January 1, 2003 and the adoption of this new standard did not have a material impact on its consolidated financial position or results of operations.

In October 2002, the EITF reached a consensus on certain issues covered in EITF 02-3. One consensus of EITF 02-3 requires that all mark-to-market gains and losses, whether realized or unrealized, on financial derivative contracts as defined in SFAS No. 133 be shown net in the Income Statement for financial statements issued for periods beginning after December 15, 2002, with reclassification required for prior periods presented. The Company adopted this consensus effective January 1, 2003 and the application of this consensus did not have a material impact on its consolidated financial position or results of operations as this consensus supports the Company's historical presentation of financial derivative contracts.

In October 2002, the EITF reached a consensus to rescind EITF 98-10 effective for fiscal periods beginning after December 15, 2002. Effective October 25, 2002, all new contracts and physical inventories that would have been accounted for under EITF 98-10 are no longer marked to market through earnings unless the contracts meet the definition of a derivative under SFAS No. 133. Application of the consensus for energy contracts and inventory that existed on or before October 25, 2002 that remained in effect at the date this consensus was initially applied were recognized as a cumulative effect of a change in accounting principle in accordance with Accounting Principles Board ("APB") Opinion No. 20, "Accounting Changes." As a result, only energy contracts that meet the definition of a derivative in SFAS No. 133 will be carried at fair value. The Company adopted this consensus effective January 1, 2003 resulting in an approximate $9.6 million pre-tax loss ($5.9 million after tax). The loss, which was accounted for as a cumulative effect of a change in accounting principle, was primarily related to natural gas held in storage for trading purposes. This natural gas held in storage was sold during the first quarter of 2003 resulting in an increase in the gross margin in excess of the cumulative effect loss described above.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation - Transition and Disclosure - an amendment of FASB Statement No. 123." SFAS No. 148 provides alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation which includes the prospective method, modified prospective method and retroactive restatement method. SFAS No. 148 also amends the disclosure requirements of SFAS No. 123, "Accounting for Stock-Based Compensation" to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. Adoption of the annual disclosure and voluntary transition requirements of SFAS No. 148 is required for annual financial statements issued for fiscal years ending after December 15, 2002. Adoption of the interim disclosure requirements of SFAS No. 148 is required for interim periods beginning after December 15, 2002. Pursuant to the provisions of SFAS No. 123, the Company has elected to continue using the intrinsic value method of accounting for its stock-based employee compensation plans in accordance with APB Opinion No. 25, "Accounting for Stock Issued to Employees."

Electric Competition; Regulation

Proposed Standard Market Design Rulemaking

In July 2002, the FERC issued a Notice of Proposed Rulemaking on Standard Market Design Rulemaking for regulated utilities. If implemented as proposed, the rulemaking will substantially change how wholesale markets operate throughout the United States. The proposed rulemaking expands the FERC's intent to unbundle transmission operations from integrated utilities and ensure robust competition in wholesale markets. The rule contemplates that all wholesale and retail customers will be on a single network transmission service tariff. The rule also contemplates the implementation of a bid-based system for buying and selling energy in wholesale markets. RTOs or Independent Transmission Providers will administer the market. RTOs will also be responsible for regional plans that identify opportunities to construct new transmission, generation or demand side programs to reduce transmission constraints and meet regional energy requirements. Finally, the rule envisions the development of Regional Market Monitors responsible for ensuring the individual participants do not exercise unlawful market power. The FERC recently extended the comment period, with the anticipation that the final rules would be in place in 2003 and the contemplated market changes would take place in 2003 and 2004. On April 28, 2003, the FERC issued a White Paper, "Wholesale Market Platform", in which the FERC expressed its core mission under the Federal Power Act to achieve wholesale electricity markets that produce just and reasonable prices and work for customers. In the White Paper, the FERC acknowledged numerous concerns raised by approximately 1,000 sets of formal comments. The FERC committed in the White Paper to work with interested parties including state commissions to find solutions that will recognize regional differences within regions subject to the FERC's jurisdiction. The White Paper discloses that the proposed rule will be changed in several respects as reflected in the White Paper and following additional regional technical conferences. In its Notice of White Paper, the FERC indicated it would be issuing notices of these conferences shortly.

Reference is made to Note 14 and Note 16 of Notes to Condensed Consolidated Financial Statements in this report and to "Electric Competition; Regulation" in Item 7 of the Company's Form 10-K for the year ended December 31, 2002 for a discussion of pending regulatory actions involving OG&E or Enogex and of other initiatives to increase competition in the retail and wholesale sale of electricity.

Commitments and Contingencies

Except as set forth below, the circumstances set forth in Note 15 to the Company's consolidated financial statements included in the Company's Form 10-K for the year ended December 31, 2002, appropriately represent, in all material respects, the current status of any material commitments and contingent liabilities.

Farmland Industries

Farmland Industries, Inc. (“Farmland”) voluntarily filed for Chapter 11 bankruptcy protection from creditors on May 31, 2002. Enogex provided gas transportation and supply services to Farmland, and is an unsecured creditor of Farmland. Enogex filed its Proof of Claim on January 7, 2003, for approximately $5.4 million. In April 2003, Enogex negotiated a settlement in which it will receive approximately $1.9 million in May 2003 which is approximately $0.3 million higher than the $1.6 million outstanding balance due (net of the $3.8 million reserve recorded in 2002).

Guarantees

During the normal course of business, Enogex issues guarantees on behalf of its subsidiaries for the purpose of securing credit for certain business activities. These guarantees are for payment when due of amounts payable by its subsidiaries under various agreements with counterparties. At March 31, 2003, accounts payable supported by guarantees was approximately $91.4 million. Since these guarantees by Enogex represent security for payment of payables obtained in the normal course of its subsidiaries business activities, the Company, on a consolidated basis, does not assume any additional liability as a result of this arrangement.

OGE Energy Corp. has issued a $5.0 million guarantee on behalf of OERI and a $15.0 million guarantee on behalf of Enogex Inc. for the purpose of securing credit for certain business activities. These guarantees are for payment when due of amounts payable by OERI and Enogex Inc. under various agreements with counterparties. At March 31, 2003, accounts payable supported by guarantees was approximately $0.1 million. Since these guarantees by OGE Energy Corp. represent security for payment of payables obtained in OERI’s and Enogex Inc.’s business activities, the Company, on a consolidated basis, does not assume any additional liability as a result of this arrangement.

As of December 31, 2002, in the event Moody’s or Standard & Poor’s were to lower Enogex’s senior unsecured debt rating to a below investment grade rating, Enogex would be required to post less than $5.0 million of collateral to satisfy its obligation under its financial and physical contracts.

Other

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies. Management consults with counsel and other appropriate experts to assess the claim. If in management’s opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company’s condensed consolidated financial statements. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of other currently

pending or threatened lawsuits and claims will have a material adverse effect on the Company’s consolidated financial position, results of operations or cash flows.

Besides the various existing contingencies herein described, the Company’s ability to fund its future operational needs and to finance its construction program could be impacted by numerous factors such as general economic conditions, abnormal weather, load growth, acquisitions of other businesses, actions by rating agencies, inflation, changes in environmental laws or regulations, rate increases or decreases allowed by regulatory agencies, new legislation and market entry of competing electric power generators.

Item 3. Quantitative and Qualitative Disclosures About Market Risk

Risk Management

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

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’s exposure to interest rate risk for changes in interest rates has not significantly changed since December 31, 2002. See Notes 10 and 11 of Notes to Condensed Consolidated Financial Statements.

Commodity Price Risk

The market risks inherent in the Company's market risk sensitive instruments, positions and anticipated commodity transactions are the potential losses in value arising from adverse changes in the Company's commodity prices.

The Company's exposure to commodity price risk has not significantly changed since December 31, 2002. See Note 3 of Notes to Condensed Consolidated Financial Statements.

Item 4. Controls and Procedures

The Company maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. Within the 90-day period prior to the filing of this report, an evaluation was carried out under the supervision and with the participation of the Company's management, including the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), of the effectiveness of the Company's disclosure controls and procedures. Based on that evaluation, the CEO and CFO have concluded that the Company's disclosure controls and procedures are effective.

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

PART II. OTHER INFORMATION

Item 1. Legal Proceedings

Reference is made to Part I, Item 3 of the Company's Form 10-K for the year ended December 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.

Item 6. Exhibits and Reports on Form 8-K

(a) Exhibits

Exhibit No.	Description
10.01	Revolving Note Agreement as amended by Amendment No. 3, dated April 6, 2003 between OGE Energy Corp. and Bank of Oklahoma, N.A.
10.02	Transportation Precedent Agreement dated October 18, 2002 between Enogex Inc. and Colorado Interstate Gas Company.
99.01	Certification Pursuant to 18 U.S.C. Section 1350 As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

(b) Reports on Form 8-K

The Company filed a Current Report on Form 8-K on January 31, 2003 to report its 2002 consolidated results of operations and financial condition.

The Company filed a Current Report on Form 8-K on April 30, 2003 to report its consolidated results of operations and financial condition for the first quarter of 2003.

The Company filed a Current Report on Form 8-K on May 6, 2003 to report additional financial data discussed in the Company's first quarter 2003 earnings conference call.

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)

May 15, 2003

CERTIFICATIONS

I, Steven E. Moore, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: May 15, 2003

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

CERTIFICATIONS

I, James R. Hatfield, certify that:

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

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

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

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

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

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

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

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

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

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

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

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Date:  May 15, 2003

/s/ James R. Hatfield
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    James R. Hatfield
    Senior Vice President and
      Chief Financial Officer
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Exhibit 10.01

THIRD AMENDMENT TO LOAN AGREEMENT

This Third Amendment to Loan Agreement (the "Third Amendment") is made effective as of April 6, 2003, by and among **OGE Energy Corp.**, an Oklahoma corporation (**"Borrower"**), and **Bank of Oklahoma, N.A.**, a national banking association ("Lender").

R E C I T A L S:

A. Borrower and the Lender previously entered into a Loan Agreement dated April 6, 2001, a First Amendment to Loan Agreement dated June 29, 2001 and a Second Amendment dated April 6, 2002 (collectively, the "Loan Agreement"), which governs an extension of credit to the Borrower in the maximum principal amount of $15,000,000.00.

B. The Borrower and the Lender desire to amend the Loan Agreement as hereafter described.

NOW, THEREFORE, in consideration of the mutual covenants and agreements herein contained, the parties hereto agree as follows:

a) The definition of "Termination Date" is amended to mean April 6, 2004.

b) The definition of "364-Day Facility" is amended to mean the Amended and Restated Credit Agreement dated as of January 8, 2003, between Borrower and Bank of America, N.A., as administrative agent, Banc of America Securities LLC and Wachovia

Securities, Inc., as Joint Lead Arrangers and Co-Book Managers and the various lenders from time to time a party thereto.

c) The definition of "Note" is amended to mean the renewal promissory note in the form attached to this Third Amendment to Loan Agreement as Exhibit A, which will be executed and delivered by the Borrower to evidence the $15,000,000 extension of credit.

2. Representations, Warranties and Agreements. In order to induce the Lender to enter into this Third Amendment, the Borrower represents and warrants to the Lender as follows:

(a) Authorization and Enforceability. This Third Amendment and any other documents to be executed and delivered by Borrower in connection therewith, when executed and delivered in accordance with the terms hereof, are and shall be the legal, valid and binding obligation of Borrower and enforceable in accordance with their respective terms. The making and performance of this Third Amendment and the execution and delivery of the various instruments associated therewith have been duly authorized by the Borrower, and neither the execution nor delivery of this Third Amendment or the other instruments contemplated hereby, nor fulfillment of or compliance with their respective terms and provisions, requires any consent, approval or other action by, or any notice to or filing with, any governmental agency or tribunal, or will conflict with, or result in a breach of the terms, conditions or provisions of, or

constitute a default under, or result in the creation of any lien upon any of the properties or assets of Borrower pursuant to its organizational documents or any other agreement, instrument or law to which Borrower is subject.

(b) Adoption of Representation and Warranties. The Borrower hereby represents and warrants to the Lender that all of the representations and warranties contained in the 364-Day Facility are true and correct in all material respects as of the effective date of this Third Amendment, and all such representations and warranties are incorporated herein by reference.

(c) Other Agreements. Except as expressly amended by this Third Amendment and, to the extent contained in Section 6 of the 364-Day Facility, as provided in the 364-Day Facility, Borrower hereby adopts and remakes to the Lender all of its respective agreements and covenants contained in the Loan Agreement and/or in the other Loan Documents, effective as of the effective date of this Third Amendment, and all such agreements and covenants are incorporated herein by reference.

3. Costs, Fees and Expenses. The Borrower agrees to pay to the Lender all reasonable costs and expenses, including reasonable attorneys' fees, incurred by the Lender in connection with the preparation, execution and delivery of this Third Amendment.

4. Adoption of Loan Agreement. The Borrower expressly agrees to be bound by and comply with all terms and provisions of the Loan Agreement, as amended. Except as modified herein, the terms and conditions of the Loan Agreement shall remain unchanged, and the Loan Agreement shall continue in full force and effect in accordance with its terms. The Borrower further represents to the Lender that, as of the effective date of this Third Amendment, Borrower has no defenses, setoffs or counterclaims of any kind or nature against the Lender with respect to the Loan Agreement of any of the obligations thereunder or any action previously taken or not taken by the Lender with respect thereto.

IN WITNESS WHEREOF, the parties have executed this Third Amendment on the 6th day of April 2003.

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BORROWER:                                 OGE ENERGY CORP., an Oklahoma
                                          corporation


                                          By: /s/ Eric B. Weekes
                                             ------------------------------
                                          Name:   Eric B. Weekes
                                          Title:  Treasurer


BANK:                                     BANK OF OKLAHOMA, N.A., a national
                                          banking association


                                          By: /s/ Laura Christofferson
                                             ------------------------------
                                          Name:   Laura Christofferson
                                          Title:  Senior Vice President
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Exhibit 10.02

Cheyenne Plains Pipeline
Transportation Precedent Agreement

This Cheyenne Plains Pipeline Transportation Precedent Agreement (TPA) dated 10-18-02, is between Colorado Interstate Gas Company (CIG) or such related entity as CIG may designate (Transporter) and Enogex, Inc. (Shipper). In consideration of the mutual promises of the parties, Transporter and Shipper agree as follows:

1. Definitions. The capitalized terms used in this TPA have the meaning set forth in the attached Exhibit A or as defined within the TPA.

2. Cheyenne Plains Pipeline Project. Subject to the terms and conditions of this TPA, Transporter shall construct the pipeline project that is currently known as the Cheyenne Plains Pipeline Project as defined in Exhibit A (the Cheyenne Plains Pipeline).

A. Capacity. The pipeline diameter and throughput capacity of the Cheyenne Plains Pipeline shall be determined by Transporter based upon shipper commitments and may range from a 24-inch to 30-inch diameter pipeline with a total throughput of 350 MDth/day to 540 MDth/day. The capacity shall be allocated in the manner provided in the Open Season for the Cheyenne Plains Pipeline (based on the present value of the annual reservation rate per unit for each offer).

B. Progress Dates. Subject to the following and to the other provisions of this TPA, Transporter shall make good faith efforts to achieve an In-Service Date by August 31, 2005, subject to timely receipt by Transporter of the FERC Certificate and all other necessary permits and authorizations for the construction and operation of the Cheyenne Plains Pipeline. Transporter anticipates filing its certificate application with the FERC by April 30, 2003.

3. FTSA. Subject to the other provisions of this TPA, Shipper and Transporter shall execute a Firm Transportation Service Agreement ("FTSA") at least 30 days prior to the FERC Filing Date. The FTSA shall be in that form included as a part of the Tariff applicable to the Cheyenne Plains Pipeline and shall be subject to the terms of the Tariff as approved by the Commission and shall further contain the following provisions:

A. Initial Term. The term of the FTSA shall commence on the In-Service Date and shall remain in effect for a period of ten years and 2 months (l0.l667) years (CIG anticipates that terms of at least 10 years will be necessary to support the project economics).

B. Rates and Surcharges

i. Rates. Shipper must select either the Recourse Rate Option(s) or the Negotiated Rate Option(s) listed below. If the Shipper selects the Recourse Rate Option(s) the Shipper may select either the Recourse Rate Applicable to the 30-inch Pipeline only

or the Shipper may select both the Recourse Rate Applicable to the 30-inch Pipeline and the Recourse Rate Applicable to the 24-inch Pipeline. If the Shipper selects the Recourse Rate for the 30-inch Pipeline only, and CIG elects to proceed with the 24-inch pipeline, Shipper's bid shall be treated as a bid on the 24-inch project at a discounted rate of $0.34. If the Shipper selects the Negotiated Rate Option(s) the Shipper may select either the Base Negotiated Rate only (which would be applicable to any project the Transporter builds) or the Shipper may select both the Base Negotiated Rate and the Alternative Negotiated Rate (which shall be applicable only if Transporter builds the 24-inch pipeline). Shipper shall designate its choice(s) by checking and initialing the appropriate box:

Recourse Rate(s):

- Recourse Rate Applicable to the 30-inch Pipeline: Shipper shall pay maximum Tariff rates for the 30-inch pipeline for transportation service from the Primary Point(s) of Receipt to the Primary Point(s) of Delivery described herein as such rate is established and adjusted by the FERC from time to time.

- Recourse Rate Applicable to the 24-inch Pipeline: Shipper shall pay maximum Tariff rates for the 24-inch pipeline for transportation service from the Primary Point(s) of Receipt to the Primary Point(s) of Delivery described herein as such rate is established and adjusted by the FERC from time to time.

Negotiated Rate(s):

[X] Base Negotiated Rate: Shipper shall pay negotiated reservation rates of $10.3417 per month. (The monthly reservation charge is equivalent to a rate of $0.34 per Dth per day on a 100% load factor basis.)

[X] Alternative Negotiated Rate for the 24-inch Diameter Pipeline: In the event Transporter elects to construct a 24-inch diameter pipeline, Shipper shall pay negotiated reservation rates of $10.9500 per month. (The monthly reservation charge is equivalent to a rate of $0.36 per Dth per day on a 100% load factor basis.)

Under the negotiated rates there will be no commodity or usage charge, unless Transporter is required by the FERC to assess such a commodity charge, in which event the commodity charge shall be set at the minimum permissible level and the reservation rate described above shall be reduced to a level that causes the combined commodity and reservation rates to equal a 100% load factor rate of the bid amount. Should the FERC or a court with jurisdiction issue a ruling that has the effect of prohibiting Transporter from collecting, or penalizing Transporter for collecting, the rates and revenues provided for herein, then the parties agree to enter into a substitute lawful arrangement, such that the parties are placed in the same economic position as if Transporter had collected such rates.

ii. Surcharges. In addition to the reservation rate, Shipper shall pay applicable fuel and L&U charges (anticipated to be less than 1%), ACA, and all other surcharges applicable to transportation on the Cheyenne Plains Pipeline under the Tariff.

C. MDQ. Subject to being awarded sufficient capacity, and subject to the adjustments described in Section 2.A above, Shipper's MDQ under the FTSA shall be 60,000 Dth per day.

D. Points of Receipt and Delivery; Pressure; Gas Quality

i. Primary Point of Receipt. The Primary Point of Receipt shall be determined prior to signing the FTSA but options shall include interconnects at or near the Cheyenne Hub in Section 5, Township 11N, Range 66W, Weld County, Colorado: CIG; WIC (including the WIC Medicine Bow Lateral). Additionally, interconnect agreements with other pipelines will be pursued (if such interconnects are requested by Shippers as Primary Points) provided that the incremental costs of such additional interconnects are acceptable to Transporter in its sole discretion.

ii. Primary Point of Delivery. The Primary Point of Delivery shall be determined prior to signing the FTSA but options shall include interconnects between the Cheyenne Plains Pipeline and the facilities of ANR, NGPL, NNG, Williams, PEPL, and the Mid-Continent Market Center at or near ANR's Greensburg Compressor Station in Kiowa County, Kansas. Transporter shall deliver the gas to such interconnects at sufficient pressure to enter the interconnecting pipelines, but not to exceed 880 p.s.i.g., provided that: (a) Shippers select such interconnects as Primary Points of Delivery; b) the cost of such interconnects are acceptable to Transporter in its sole discretion; and (c) Transporter is able to negotiate mutually agreeable interconnection agreements with these pipelines. Shipper shall have the right to utilize as Secondary Points of Delivery, at no additional cost, any other interconnects that are installed.

iii. Pressure at Points of Receipt. Gas tendered to the Cheyenne Plains Pipeline shall be at a pressure sufficient to enter the pipeline. Such pressure shall be a minimum of 920 p.s.i.g. and not exceed 1000 p.s.i.g. at the Cheyenne Hub receipt points.

iv. Quality. Gas tendered to the Cheyenne Plains Pipeline for transportation at Points of Receipt and by Transporter at Points of Delivery shall meet the same quality provisions as are found in the FERC Gas Tariff of Wyoming Interstate Company, Ltd.

4. Conditions to Transporter's Obligations. Transporter's obligations under this TPA and the FTSA are subject to: (a) Shipper providing evidence of creditworthiness in a manner satisfactory to Transporter equal to at least one year of contract revenue (satisfactory evidence of creditworthiness may include a Letter of Credit, a guarantee from a creditworthy party or a satisfactory review of the financial status of the Shipper by Transporter); (b) compliance by Shipper with the terms of the applicable Tariff; (c) receipt by Transporter of the FERC

Certificate as well as all other authorizations and permits required for the construction and operation of the Cheyenne Plains Pipeline, all on terms satisfactory to Transporter in its sole discretion; (d) the approval of the terms of this TPA by Transporter's or Transporter's parent corporation's (or successor entity's) Board of Directors, as applicable, by December 31, 2002; (e) the execution by other shippers and Transporter of such additional firm transportation commitments, in a form substantially similar to this TPA, which are sufficient, in Transporter's sole discretion, to support the construction of the Cheyenne Plains Pipeline, and the approval thereof by such other shippers' Boards of Directors by October 31, 2002, under the terms of this TPA; and (f) satisfaction of the conditions to Shipper's performance set forth in Paragraph 5 of this TPA.

5. Conditions to Shipper's Obligations. Shipper's obligations under this TPA are subject to the approval of the terms of this TPA by Shipper's management or Board of Directors, as applicable, by October 31, 2002.

6. Notice. All notices required or permitted under this TPA shall be in writing and shall be deemed to have been properly given or delivered when delivered personally, when sent by telefax or when sent by overnight delivery service, with all charges fully prepaid, and addressed to the parties hereto, respectively, as follows:

Cheyenne Plains Pipeline Project
c/o Colorado Interstate Gas Company
2 North Nevada Avenue
Colorado Springs, Colorado 80903
Attention: Thomas L. Price
Fax: (719) 520-4810

Enogex, Inc.
515 Central Park Drive, Suite 600
Oklahoma City, OK 73105

Attention: James H. Lindsay
Fax: 405-553-6900

Each party has the right to change its address for all purposes of this TPA by notifying the other party thereof in writing.

7. Assignment. Except that CIG may assign this TPA to an affiliated entity to be designated by CIG, neither party may assign its rights or obligations under this TPA without the written consent of the other party, which consent shall not be unreasonably withheld. Assignment of the FTSA shall be governed by the terms of the Tariff.

8. Term of this Agreement. This TPA shall be effective on the date hereof and, unless terminated earlier in accordance with the terms hereof, shall remain in effect until the execution of the replacement FTSA.

9. Offer Expiration Date. The offer by Transporter to Shipper set forth in this TPA shall expire on November 1, 2002, unless Transporter and Shipper have executed this TPA by such date.

10. Applicable Law. THIS TPA AND THE LEGAL RELATIONS BETWEEN THE PARTIES WITH RESPECT TO SUCH TPA ARE SUBJECT TO ALL APPLICABLE LAWS, RULES, AND REGULATIONS AND SHALL BE GOVERNED AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF COLORADO WITHOUT REGARD TO RULES CONCERNING CONFLICTS OF LAW.

Executed as of the date first above written.

Transporter:	Shipper:
Colorado Interstate Gas Company	Enogex, Inc.
By: /s/ Donald Zinko	By: /s/ James H. Lindsay
Donald Zinko Vice President	James H. Lindsay Vice President

Exhibit A
DEFINED TERMS

In addition to those terms defined in the TPA, the following terms used in the TPA have the meanings indicated:

Cheyenne Plains Pipeline Project means new gas transmission facilities extending from interconnects at or near WIC's and CIG's Cheyenne Compressor Station in Section 5, Township 11N, Range 66W, Weld County, Colorado, to interconnects at or near ANR's Greensburg Compressor Station in Kiowa County, Kansas.

FERC means the Federal Energy Regulatory Commission.

FERC Certificate means a certificate of public convenience and necessity issued by the FERC for the construction and operation of the Cheyenne Plains Pipeline, as such certificate may be amended.

FERC Filing Date is the date Transporter files the initial application, substantially complete, for the FERC Certificate for the Cheyenne Plains Pipeline.

FTSA is a Firm Transportation Service Agreement pursuant to the Tariff for firm transportation service on Cheyenne Plains Pipeline.

In-Service Date is the first day of the month following the date the Cheyenne Plains Pipeline is completed and ready for service.

MDQ means, as set forth in the Tariff, Maximum Delivery Quantity.

Tariff means the FERC Gas Tariff governing transportation for the Cheyenne Plains Pipeline, as the same may be amended or superseded from time to time. The parties anticipate that the tariff applicable to the Cheyenne Plains Pipeline will be substantially similar to the tariff for Wyoming Interstate Company, Ltd. or for Colorado Interstate Gas Company.

CHEYENNE PLAINS OPEN SEASON
OFFER SHEET

A. Shipper Name:
Enogex, Inc.

B. Term of service = 10 years and 2 months (from the actual in-service date) (CIG anticipates that terms of at least 10 years will be necessary to support the project economics).

C. Bid MDQ: 60,000 Dth per Day

MDQ awarded (to be completed by CIG): --

D. Primary Receipt/Delivery Point(s):

Primary Receipt Points (Note 1)		MDQ (Quantity in Dth)
TBD		60,000
	TOTAL	

Primary Delivery Points (Note 2)		MDQ (Quantity in Dth)
	TOTAL	60,000

E. Rates:

Recourse Rate(s): (Note 3)

- Recourse Rate Applicable to the 30-inch Pipeline: Shipper shall pay maximum Tariff rates for the 30-inch pipeline for transportation service from the Primary Point(s) of Receipt to the Primary Point(s) of Delivery described herein as such rate is established and adjusted by the FERC from time to time.

- Recourse Rate Applicable to the 24-inch Pipeline: In the event Transporter elects to construct a 24-inch diameter pipeline, Shipper shall pay maximum Tariff rates for the 24-inch pipeline for transportation service from the Primary Point(s) of Receipt to the Primary Point(s) of Delivery described herein as such rate is established and adjusted by the FERC from time to time.

Negotiated Rate(s): (Note 4)

[X] Base Negotiated Rate: Shipper shall pay negotiated reservation rates of $10.3417 per month. (A monthly reservation charge of $10.3417 is equivalent to a rate of $0.34 per Dth per day on a 100% load factor basis and is the rate anticipated to be required tar the 30-inch pipeline project to be economically viable.)

[X] Alternative Negotiated Rate for the 24-inch Diameter Pipeline: In the event Transporter elects to construct a 24-inch diameter pipeline, Shipper shall pay negotiated reservation rates of $10.95 per month. (A monthly reservation charge of $l0.9500 is equivalent to a rate of $0.36 per Dth per day on a 100% load factor basis and is the rate anticipated to be required for the 24-inch pipeline project to be economically viable.)

F. Conditions:
- Shipper will be allowed eight business days from notification by CIG of bid acceptance in which to obtain any required Board of Directors (or similar organizational) approval.
- Shipper will be allowed 30 days to obtain any state regulatory approvals (Note: this condition is applicable only if shipper is a jurisdictional utility).

NOTE: Recourse bid rates do not include Commodity Charges, ACA, FL&U, or other authorized surcharges, if any. Such charges are additional to the Bid Rate.

1. Currently anticipated receipt points at the Cheyenne Hub include CIG, WIC, WIC Medicine Bow, Front Range Pipeline and KMI.

2. Currently anticipated delivery points include ANR, Northern Natural Gas, NGPL, PEPL, and Williams.

3. If a Shipper selects the recourse rate for the 30-inch pipeline only (and does not check and initial the box for the recourse rate for the 24-inch pipeline), and if CIG determines the bids do not support the 30-inch pipeline and proceeds with the 24-inch pipeline, Shipper's bid rate will be assumed to be a discounted rate of $0.34 on the 24-inch pipeline.

4. The Shipper may select either the Base Negotiated Rate only (which would be applicable to any project the Transporter builds) or the Shipper may select both the Base Negotiated Rate and the Alternative Negotiated Rate (which shall be applicable only if Transporter builds the 24-inch pipeline). Under the negotiated rate(s) there will be no commodity or usage charge, unless Transporter is required to assess such a commodity charge, in which event the commodity charge shall be set at the minimum permissible level and the reservation rate described above shall be reduced to a level that causes the combined commodity and reservation rates to equal the 100% load factor rate bid. Should the FERC or a court with jurisdiction issue a ruling that has the effect of prohibiting Transporter from collecting, or penalizing Transporter for collecting, the rates provided for herein, then the parties agree to enter into a substitute lawful arrangement, such that the parties are placed in the same economic position as if Transporter had collected such rates.

Exhibit 99.01

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

In connection with the Quarterly Report of OGE Energy Corp. (the "Company") on Form 10-Q for the period ended March 31, 2003, as filed with the Securities and Exchange Commission (the "Report"), each of the undersigned does hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

May 15, 2003

/s/ Steven E. Moore

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

/s/ James R. Hatfield

James R. Hatfield
Senior Vice President and
Chief Financial Officer