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

FORM 10-K

(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2004

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ______ to ______ Commission File Number 1-1097

Oklahoma Gas and Electric Company meets the conditions set forth in General Instruction I(1) (a) and (b) of Form 10-K and is therefore filing this form with the reduced disclosure format permitted by General Instruction I(2).

OKLAHOMA GAS AND ELECTRIC COMPANY

(Exact name of registrant as specified in its charter)

Oklahoma	**73-0382390**
(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)
Registrant's telephone number, including area code: **(405) 553-3000**

Securities registered pursuant to Section 12(b) of the Act: None

Securities registered pursuant to Section 12(g) of the Act: None

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 if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [ ]

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ____ No X

As of June 30, 2004, the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of shares of common stock held by non-affiliates was $0. As of such date, 40,378,745 shares of common stock, par value $2.50 per share, were outstanding, all of which were held by OGE Energy Corp.

As of January 31, 2005, 40,378,745 shares of common stock, par value $2.50 per share, were outstanding, all of which were held by OGE Energy Corp. There were no other shares of capital stock of the registrant outstanding at such date.

DOCUMENTS INCORPORATED BY REFERENCE

None

OKLAHOMA GAS AND ELECTRIC COMPANY

FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2004

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PART I

Item 1. Business.

THE COMPANY

Oklahoma Gas and Electric Company (the "Company") generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas and is subject to regulation by the Oklahoma Corporation Commission ("OCC"), the Arkansas Public Service Commission ("APSC") and the Federal Energy Regulatory Commission ("FERC"). The Company is a wholly-owned subsidiary of OGE Energy Corp. ("Energy Corp.") which is an energy and energy services provider offering physical delivery and management of both electricity and natural gas primarily in the south central United States. The Company was incorporated in 1902 under the laws of the Oklahoma Territory and is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. The Company sold its retail gas business in 1928 and is no longer engaged in the gas distribution business. The Company's principal executive offices are located at 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321; telephone (405) 553-3000.

The Company 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 the Company 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 the Company conducts its business. These developments at the federal and state levels are described in more detail in Note 13 of Notes to Financial Statements.

Company Strategy

In early 2002, Energy Corp. 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, Energy Corp. recognized that immediate deregulation of the retail electric markets in Oklahoma and Arkansas was very unlikely and revised its business strategy. In the summer of 2004, Energy Corp. again reviewed its business strategy in light of significant changing market and regulatory trends such as the over supply of electric generation, the evolution of electric transmission markets and rules, the natural gas supply forecast, the sustained increase of natural gas commodity prices and the anticipated emergence of liquefied natural gas. Energy Corp. concluded that its existing business strategy of utilizing a diversified asset position was the proper course.

Energy Corp.'s vision is to be a regional energy company focused on its regulated utility business and natural gas pipeline business of its wholly-owned natural gas pipeline subsidiary, Enogex Inc. and subsidiaries ("Enogex"), that is recognized for operational excellence and financial performance. Energy Corp. intends to maintain the majority of its assets in the

regulated utility business complemented by its natural gas pipeline business. Energy Corp.'s long-term financial goals include earnings growth of four to five percent on a normalized basis, a dividend payout ratio below 75 percent and an A- credit rating. The Company has embarked on a Customer Savings and Reliability Plan that provides for increased investment at the utility to (i) improve reliability to meet load growth; (ii) replace aging infrastructure; and (iii) deploy newer technology to improve operational and environmental performance. Capacity payment savings from reduced cogeneration payments and fuel savings from the acquisition of a 77 percent interest in the 520 megawatt ("MW") NRG McClain Station (the "McClain Plant") will be utilized to mitigate the price increases associated with these investments.

Energy Corp.'s business strategy is to continue maintaining the diversified asset position of the Company and Enogex so as to provide competitive energy products and services to customers primarily in the south central United States. Energy Corp. will focus on those products and services with limited or manageable commodity exposure. Energy Corp. intends for the Company to continue as a vertically integrated utility engaged in the generation, transmission and distribution of electricity and to represent over time approximately 70 percent of Energy Corp.'s consolidated assets. The remainder of Energy Corp.'s consolidated assets will be in Enogex's businesses. At December 31, 2004, the Company and Enogex represented approximately 63 percent and 36 percent, respectively, of Energy Corp.'s consolidated assets. The remaining one percent of Energy Corp.'s consolidated assets were primarily at the holding company. In addition to the incremental growth opportunities that Enogex provides, Energy Corp. believes that many of the risk management practices, commercial skills and market information available from Enogex provide value to all of Energy Corp.'s businesses subject to the evolving federal regulations of the FERC in regard to the operations of the wholesale power market. In addition, Oklahoma and Arkansas legislatures and utility commissions may propose changes from time to time that could subject utilities to market risk. Accordingly, Energy Corp. is applying risk management practices to all of its operations in an effort to mitigate the potential adverse effect of any future regulatory changes. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Executive Overview" for a further discussion.

General

The Company furnishes retail electric service in 269 communities and their contiguous rural and suburban areas. During 2004, seven other communities and five rural electric cooperatives in Oklahoma and western Arkansas purchased electricity from the Company for resale. The service area, with an estimated population of 1.9 million, covers approximately 30,000 square miles in Oklahoma and western Arkansas, including Oklahoma City, the largest city in Oklahoma, and Fort Smith, Arkansas, the second largest city in that state. Of the 269 communities that the Company serves, 243 are located in Oklahoma and 26 in Arkansas. The Company derived approximately 89 percent of its total electric operating revenues for the year ended December 31, 2004 from sales in Oklahoma and the remainder from sales in Arkansas.

The Company's system control area peak demand as reported by the system dispatcher during 2004 was approximately 5,823 MWs on August 3, 2004.

The Company's load

responsibility peak demand was approximately 5,460 MWs on August 3, 2004, resulting in a capacity margin of approximately 22.3 percent. As reflected in the table on the following page and in the operating statistics on page 6, there were approximately 24.8 million megawatt-hour ("MWH") sales in 2004 as compared to approximately 25.1 million in 2003 and 24.9 million in 2002. MWH sales to the Company's customers ("system sales") decreased approximately 0.1 percent in 2004 primarily due to milder weather during 2004. Sales to other utilities and power marketers ("off-system sales") remained flat in 2004. Variances in off-system sales are due in large part to the changing supply and demand needs on the Company's generation system and the market for off-system sales.

Variations in MWH sales for the three years are reflected in the following table:

	2004	**Increase/ (Decrease)**	2003	Increase/ (Decrease)	2002	Increase/ (Decrease)
System Sales (A)	**24.7**	**(0.1)%**	25.0	1.6%	24.6	0.4%
Off-System Sales (A)	**0.1**	**---%**	0.1	(67.0)%	0.3	(25.0)%
Total Sales	**24.8**	**(0.1)%**	25.1	0.8%	24.9	---%

(A) Sales are in millions of MWHs.

The Company is subject to competition in various degrees from government-owned electric systems, municipally-owned electric systems, rural electric cooperatives and, in certain respects, from other private utilities, power marketers and cogenerators. Oklahoma law forbids the granting of an exclusive franchise to a utility for providing electricity.

Besides competition from other suppliers or marketers of electricity, the Company competes with suppliers of other forms of energy. The degree of competition between suppliers may vary depending on relative costs and supplies of other forms of energy. See Note 13 of Notes to Financial Statements for a discussion of the potential impact on competition from federal and state legislation.

OKLAHOMA GAS AND ELECTRIC COMPANY
CERTAIN OPERATING STATISTICS

Year ended December 31 *(In millions)*	**2004**	2003	2002
ELECTRIC ENERGY			
(Millions of MWH)			
Generation (exclusive of station use)	**22.6**	22.5	23.4
Purchased	**4.2**	4.5	3.5
Total generated and purchased	**26.8**	27.0	26.9
Company use, free service and losses	**(2.0)**	(1.9)	(2.0)
Electric energy sold	**24.8**	25.1	24.9
ELECTRIC ENERGY SOLD			
(Millions of MWH)			
Residential	**7.9**	8.2	8.0
Commercial	**5.7**	5.8	5.8
Industrial	**7.0**	6.8	6.6
Public authorities	**2.7**	2.7	2.7
Sales for resale	**1.4**	1.5	1.5
System sales	**24.7**	25.0	24.6
Off-system sales	**0.1**	0.1	0.3
Total sales	**24.8**	25.1	24.9
ELECTRIC OPERATING REVENUES			
(In millions)			
Residential	$ **611.4**	$ 601.4	$ 557.6
Commercial	**389.9**	372.5	346.9
Industrial	**326.7**	293.4	258.6
Public authorities	**158.5**	146.1	135.5
Sales for resale	**57.0**	57.7	48.2

Provision for refund on gas transportation and storage case	**(6.9)**	---	---
Other	**40.7**	41.9	34.9
System sales revenues	**1,577.3**	1,513.0	1,381.7
Off-system sales revenues	**0.8**	4.1	6.3
Total Electric Operating Revenues	**$ 1,578.1**	$ 1,517.1	$ 1,388.0

ACTUAL NUMBER OF ELECTRIC CUSTOMERS			
(At end of period)			
Residential	**630,736**	622,527	616,712
Commercial	**80,786**	80,265	79,768
Industrial	**9,420**	8,970	8,698
Public authorities	**14,022**	13,658	13,280
Sales for resale	**44**	50	55
Total	**735,008**	725,470	718,513

AVERAGE RESIDENTIAL CUSTOMER SALES			
Average annual revenue	**$ 975.08**	$ 970.04	$ 907.95
Average annual use (kilowatt-hour (“KWH”))	**12,630**	13,202	13,095
Average price per KWH (cents)	**$ 7.72**	$ 7.35	$ 6.93

Regulation and Rates

The Company’s retail electric tariffs are regulated by the OCC in Oklahoma and by the APSC in Arkansas. The issuance of certain securities by the Company is also regulated by the OCC and the APSC. The Company’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 the Company’s facilities and operations. For the year ended December 31, 2004, approximately 87 percent of the Company’s electric revenue was subject to the jurisdiction of the OCC, nine percent to the APSC and four percent to the FERC.

The OCC issued an order in 1996 authorizing the Company to reorganize into a subsidiary of Energy Corp. The order required that, among other things, (i) Energy Corp. permit the OCC access to the books and records of Energy Corp. and its affiliates relating to transactions with the Company; (ii) Energy Corp. employ accounting and other procedures and controls to protect against subsidization of non-utility activities by the Company’s customers; and (iii) Energy Corp. refrain from pledging the Company assets or income for affiliate transactions.

Regulatory Matters and Plant Acquisition

In November 2002, the OCC issued an order containing provisions of an agreed-upon settlement of the Company’s rate case. The terms of this settlement included, among other things, a $25.0 million annual reduction in electric rates and a requirement for the Company to acquire 400 MWs of electric generation. The rate reduction went into effect January 6, 2003 and the acquisition of a 77 percent interest in the 520 MW McClain Plant was completed on July 9, 2004. The McClain Plant, located near Newcastle, Oklahoma, is a combined cycle unit consisting of two natural-gas fired combustion turbine generators combined with a steam turbine generator. The owner of the remaining 23 percent interest in the McClain Plant is the Oklahoma Municipal Power Authority. The Company operates the plant. The purchase price was approximately $160.0 million. The Company temporarily funded the McClain Plant acquisition with short-term borrowings from Energy Corp. On August 4, 2004, the Company issued $140.0 million of long-term debt to replace these short-term borrowings. Also, on August 9, 2004, Energy Corp. made a capital contribution to the Company of approximately $153.0 million. For additional information regarding the McClain Plant acquisition and related regulatory matters, see Note 13 of Notes to Financial Statements.

Regulatory Assets and Liabilities

The Company, as a regulated utility, is subject to the accounting principles prescribed by the Financial Accounting Standards Board (“FASB”) Statement of Financial Accounting Standards (“SFAS”) No. 71, “Accounting for the Effects of Certain Types of Regulation.” SFAS No. 71 provides that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future

rates. Management’s expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment. Excluding recoverable take or pay gas charges, the McClain Plant operating and maintenance expenses, depreciation, ad valorem taxes and interest on debt, regulatory assets are being amortized and reflected in rates charged to customers over periods of up to 20 years.

The Company records certain actual or anticipated costs and obligations as regulatory assets or liabilities if it is probable, based on regulatory orders or other available evidence, that the cost or obligation will be included in amounts allowable for recovery or refund in future rates.

At December 31, 2004 and 2003, the Company had regulatory assets of approximately $137.3 million and $94.2 million, respectively, and regulatory liabilities of approximately $130.1 million and $149.7 million, respectively.

As discussed in Note 13 of Notes to Financial Statements, legislation was enacted in Oklahoma and Arkansas that was to restructure the electric utility industry in those states. The Arkansas legislation was repealed and implementation of the Oklahoma restructuring legislation has been delayed and seems unlikely to proceed during the near future. Yet, if and when implemented, this legislation could deregulate the Company's electric generation assets and cause the Company to discontinue the use of SFAS No. 71 with respect to its related regulatory balances. This may result in either full recovery of generation-related regulatory assets (net of related regulatory liabilities) or a non-cash, pre-tax write-off as an extraordinary charge, depending on the transition mechanisms developed by the legislature for the recovery of all or a portion of these net regulatory assets.

The previously enacted Oklahoma and Arkansas legislation would not affect the Company's electric transmission and distribution assets and the Company believes that the continued use of SFAS No. 71 with respect to the related regulatory balances is appropriate. However, if utility regulators in Oklahoma and Arkansas were to adopt regulatory methodologies in the future that are not based on the cost-of-service, the continued use of SFAS No. 71 with respect to the regulatory balances related to the electric transmission and distribution assets may no longer be appropriate. Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, management believes that its regulatory assets, including those related to generation, are probable of future recovery.

See Note 13 of Notes to Financial Statements for a discussion of certain regulatory matters including the gas transportation and storage contract between the Company and Enogex, security enhancements and national energy legislation.

Rate Activities and Proposals

In 2002, the Company concluded its Oklahoma rate review proceeding before the OCC. This rate review was initiated in September 2001 by the OCC Staff and was concluded by order of the OCC on November 20, 2002. The Company received OCC approval in the settlement of

its rate case (the "Settlement Agreement") for several new customer programs and rate options, as well as modifications to existing rate structures. The Guaranteed Flat Bill ("GFB") option for residential and small general service accounts allows qualifying customers the opportunity to purchase their electricity needs at a set price for an entire year. Budget-minded customers that desire a fixed monthly bill could benefit from the GFB option. A second tariff rate option approved in the Settlement Agreement is an offering to provide a "renewable energy" resource to Company's Oklahoma retail customers. This renewable energy resource is a wind power purchase program and is available as a voluntary option to all of the Company's Oklahoma retail customers. Oklahoma's availability of wind resources makes the renewable wind power option a possible choice in meeting the renewable energy needs of our conservation-minded customers. A third new rate offering available to commercial and industrial customers is levelized demand billing. This program is beneficial for medium to large size customers with seasonally consistent demand levels who wish to reduce the variability of their monthly electric bills. The last new program being offered to the Company's commercial and industrial customers and approved by the OCC is a new voluntary load curtailment program. This program provides customers with the opportunity to curtail on a voluntary basis when the Company's system conditions merit curtailment action. Customers that curtail their usage will receive payment for their curtailment response. This voluntary curtailment program seeks customers that can curtail on most curtailment event days, but may not be able to curtail every time that a curtailment event is required.

The previously discussed new rate options coupled with the Company's existing rate choices provide many tariff options for the Company's Oklahoma retail customers. The Company's rate choice flexibility, reduction in cogeneration rates, acquisition of additional generation resources and overall low costs of production and deliverability are expected to provide valuable benefits for our customers for many years to come. The Company began implementation of the new rate options during the first billing cycle in January 2003. Since many of these options are voluntary, customers may choose these options anytime after the January 2003 start date. The revenue impacts associated with these options are indeterminate in future years since customers may choose to remain on existing rate options instead of volunteering for the new rate option choices. There was no overall material impact in 2003 or 2004 associated with these new rate options, but minimal revenue variations may occur in the future based upon changes in customers' usage characteristics if they choose these new programs. In 2004, over 90 percent of the GFB pilot customers renewed for a second year under the program. The pilot program has received favorable reviews and the Company is currently considering a filing with the OCC for permanent rate status in the second quarter of 2005.

Fuel Supply

During 2004, approximately 70 percent of the Company-generated energy was produced by coal units and 30 percent by natural gas units. Of the 6,141 total MW capability reflected in the table under Item 2. Properties, approximately 3,601 MWs, or 59 percent, are from natural gas generation and approximately 2,540 MWs, or 41 percent, are from coal generation. Though the Company has a higher installed capability of generation from natural gas units, it has been more economical to generate electricity for our customers using lower priced coal. A slight decline in

the percentage of coal generation in future years is expected to result from increased usage of natural gas generation required to meet growing energy needs. Over the last five years, the weighted average cost of fuel used, by type, per million British thermal unit ("MMBtu") was as follows:

	2004	2003	2002	2001	2000
Coal	**$ 1.00**	$ 0.93	$ 0.93	$ 0.81	$ 0.87
Natural Gas	**$ 6.57**	$ 6.46	$ 3.78	$ 4.91	$ 4.93
Weighted Average	**$ 2.69**	$ 2.27	$ 1.77	$ 1.97	$ 1.96

The increase in the weighted average cost of fuel in 2004 as compared to 2003 was primarily due to increased natural gas prices and a higher amount of natural gas burned in 2004 while the increase in the weighted average cost of fuel in 2003 as compared to 2002 was primarily due to increased natural gas prices in 2003 partially offset by a lower amount of natural gas burned in 2003. The decrease in the weighted average cost of fuel in 2002 as compared to 2001 was primarily due to lower natural gas prices in 2002 partially offset by a higher amount of natural gas burned in 2002. A portion of these fuel costs is included in the base rates to customers and differs for each jurisdiction. The portion of these fuel costs that is not included in the base rates is recovered through the Company's regulatorily approved automatic fuel adjustment clauses. See Note 1 of Notes to Financial Statements. The Company currently has pending before the OCC an application to recover the costs of gas transportation and storage services provided to it by Enogex pursuant to the contract between the Company and Enogex. An adverse decision by the OCC could result in the Company having to refund previously collected amounts. See Note 13 of Notes to Financial Statements for a further discussion of this matter.

Coal

All of the Company's coal units, with an aggregate capability of approximately 2,540 MWs, are designed to burn low sulfur western coal. The Company purchases coal primarily under long-term contracts expiring in 2010 and 2011. During 2004, the Company purchased approximately 9.4 million tons of coal from the following Wyoming suppliers: Kennecott Energy Company, Arch Coal Inc., Peabody Coal Sales Company and Triton Coal Company. The combination of all coal has a weighted average sulfur content of less than 0.25 percent and can be burned in these units under existing federal, state and local environmental standards (maximum of 1.2 lbs. of sulfur dioxide per MMBtu) without the addition of sulfur dioxide removal systems. Based upon the average sulfur content, the Company's coal units have an approximate emission rate of 0.504 lbs. of sulfur dioxide per MMBtu, well within the limitations of the provisions of the Clean Air Act.

The Company has continued its efforts to maximize the utilization of its coal units at both its Sooner and Muskogee generating plants. See "Environmental Laws and Regulations" in Note 12 of Notes to Financial Statements for a discussion of an environmental proposal that, if implemented as proposed, could inhibit the Company's ability to use coal as its primary boiler fuel.

Natural Gas

In April 2004, the Company utilized a request for bid ("RFB") to acquire approximately 56 percent and 26 percent of its projected annual natural gas requirements for 2005 and 2006, respectively. All of these contracts are tied to various gas price market indices and most will expire in December 2006. Additional natural gas supply for the summer of 2005 will be secured through a new RFB issued in the first quarter of 2005. The Company will meet additional natural gas requirements with monthly and daily purchases as required.

In 1993, the Company began utilizing a natural gas storage facility that allowed the Company to maximize the value of its generation assets, which storage services are now provided by Enogex as part of Enogex's gas transportation and storage contract with the Company.

Wind

During 2003, the Company contracted with FPL Energy for 50 MWs of electricity generated at a wind farm near Woodward, Oklahoma. After more than one year of marketing wind power to the Company's residential and business customers, almost 9,000 have subscribed for all or part of their electricity usage. Since the Company last requested bids to determine the cost of adding wind to its system, natural gas prices have continued to rise and federal renewable energy tax credits have been extended. The Company is exploring adding another 80 MWs of wind-generated electricity to its system and, in December 2004, the Company issued a request for proposals from companies who produce electricity from wind. The Company expects to use the proposal responses to conduct a thorough analysis of how adding more wind will affect customers today and in the future. A decision is expected during the first or second quarter of 2005.

FINANCE AND CONSTRUCTION

Future Capital Requirements

Capital Requirements

The Company's primary needs for capital are related to replacing or expanding existing facilities in its electric utility business. Other working capital requirements are primarily related to maturing debt, operating lease obligations, hedging activities and delays in recovering unconditional fuel purchase obligations. The Company generally meets its cash needs through a combination of internally generated funds, short-term borrowings from Energy Corp. (through a combination of bank borrowings and commercial paper) and permanent financings. See "Item 7. Management's Discussion and Analysis of Financial Conditions and Results of Operations – Liquidity and Capital Requirements" for a discussion of the Company's capital requirements.

Capital Expenditures

The Company's current 2005 to 2007 construction program includes continued investment in system and transmission upgrades that is part of the Company's Customer Savings and Reliability Plan. The Company has approximately 430 MWs of contracts with qualified cogeneration facilities and small power production producers' ("QF contracts") that will expire at the end of 2007, unless extended by the Company. In addition, effective September 1, 2004, the Company entered into a new 15-year power sales agreement for 120 MWs with PowerSmith Cogeneration Project, L.P. ("PowerSmith"). The Company will continue reviewing all of the supply alternatives to these expiring QF contracts that minimize the total cost of generation to its customers, including exercising its options (if applicable) to extend these QF contracts at pre-determined rates. Accordingly, the Company will continue to explore opportunities to build or buy power plants in order to serve its native load. As a result of the high volatility of current natural gas prices and the increase in natural gas prices, the Company will also assess the feasibility of constructing additional base load coal-fired units. See "Item 7. Management's Discussion and Analysis of Financial Conditions and Results of Operations – Liquidity and Capital Requirements" for a discussion of the Company's capital expenditures.

Pension and Postretirement Benefit Plans

During 2004 and 2003, Energy Corp. made contributions of approximately $69.0 million and $50.0 million, respectively, to ensure the pension plan maintains an adequate funded status of which approximately $54.5 million and $38.8 million, respectively, was allocated to the Company. During 2005, Energy Corp. plans to contribute approximately $37.4 million to the pension plan, of which approximately $29.0 million is expected to be allocated to the Company. See "Item 7. Management's Discussion and Analysis of Financial Conditions and Results of Operations – Liquidity and Capital Requirements" for a discussion of Energy Corp.'s pension and postretirement benefit plans.

Future Sources of Financing

Management expects that internally generated funds, funds received from Energy Corp. (from proceeds from the sales of its common stock pursuant to Energy Corp.'s Automatic Dividend Reinvestment and Stock Purchase Plan) and long and short-term debt will be adequate over the next three years to meet anticipated capital expenditures, operating needs, payment of dividends and maturities of long-term debt. As discussed below, the Company utilizes short-term borrowings from Energy Corp. (through a combination of bank borrowings and commercial paper) to satisfy temporary working capital needs and as an interim source of financing capital expenditures until permanent financing is arranged.

Short-Term Debt

Short-term borrowings from Energy Corp. generally are used to meet working capital requirements. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Requirements – Future Sources of Financing" for a

table showing Energy Corp.'s and the Company's lines of credit in place and available cash at January 31, 2005. At January 31, 2005, the Company had no short-term debt outstanding and had approximately $44.8 million in outstanding advances from Energy Corp. Also, at January 31, 2005, Energy Corp.'s short-term borrowings consisted of commercial paper.

ENVIRONMENTAL MATTERS

Approximately $5.3 million of the Company's capital expenditures budgeted for 2005 are to comply with environmental laws and regulations. The Company's management believes that all of its operations are in substantial compliance with present federal, state and local environmental standards. It is estimated that the Company's total expenditures for capital, operating, maintenance and other costs to preserve and enhance environmental quality will be approximately $54.3 million during 2005, as compared to approximately $52.2 million in 2004. The Company continues to evaluate its environmental management systems to ensure compliance with existing and proposed environmental legislation and regulations and to better position itself in a competitive market. See Note 12 of Notes to Financial Statements for a discussion of environmental matters, including the impact of existing and proposed environmental legislation and regulations.

EMPLOYEES

The Company had 1,982 employees at December 31, 2004.

ACCESS TO SECURITIES AND EXCHANGE COMMISSION FILINGS

Energy Corp.'s web site address is *www.oge.com*. Through Energy Corp.'s web site under the heading "Investors", "SEC Filings," Energy Corp. makes available, free of charge, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission.

Item 2. Properties.

The Company owns and operates an interconnected electric generation, transmission and distribution system, located in Oklahoma and western Arkansas, which includes nine generating stations with an aggregate capability of approximately 6,141 MWs. The following table sets forth information with respect to the Company's electric generating facilities, all of which are located in Oklahoma:

Station & Unit		Year Installed	Unit Design Type	Fuel Capability	Unit Run Type	2004 Capacity Factor (A)	Unit Capability (MWs)	Station Capability (MWs)
Seminole	1	1971	Steam-Turbine	Gas	Base Load	25.5%	506.0	
	1GT	1971	Combustion-Turbine	Gas	Peaking	0.01%(B)	15.4	
	2	1973	Steam-Turbine	Gas	Base Load	28.1%	507.6	
	3	1975	Steam-Turbine	Gas/Oil	Base Load	25.4%	516.8	1,545.8
Muskogee	3	1956	Steam-Turbine	Gas	Base Load	6.6%	166.0	
	4	1977	Steam-Turbine	Coal	Base Load	77.0%	500.5	
	5	1978	Steam-Turbine	Coal	Base Load	70.4%	521.6	
	6	1984	Steam-Turbine	Coal	Base Load	63.4%	499.0	1,687.1
Sooner	1	1979	Steam-Turbine	Coal	Base Load	80.8%	505.2	
	2	1980	Steam-Turbine	Coal	Base Load	64.8%	513.8	1,019.0

Horseshoe	6	1958	Steam-Turbine	Gas/Oil	Base Load	17.8%	168.5	
Lake	7	1963	Combined Cycle	Gas/Oil	Base Load	17.4%	234.0	
	8	1969	Steam-Turbine	Gas	Base Load	7.8%	380.5	
	9	2000	Combustion-Turbine	Gas	Peaking	9.1%(B)	45.5	
	10	2000	Combustion-Turbine	Gas	Peaking	9.1%(B)	45.5	874.0
Mustang	1	1950	Steam-Turbine	Gas	Peaking	0.6%(B)	53.0	
	2	1951	Steam-Turbine	Gas	Peaking	0.6%(B)	53.0	
	3	1955	Steam-Turbine	Gas	Base Load	19.0%	117.5	
	4	1959	Steam-Turbine	Gas	Base Load	17.6%	250.0	
	5	1971	Combustion-Turbine	Gas/Jet Fuel	Peaking	0.6%(B)	60.0	533.5
Conoco	1	1991	Combustion-Turbine	Gas	Base Load	66.5%	31.5	
	2	1991	Combustion-Turbine	Gas	Base Load	69.8%	31.0	62.5
Enid	1	1965	Combustion-Turbine	Gas	Peaking	---(C)	---	
	2	1965	Combustion-Turbine	Gas	Peaking	---(C)	---	
	3	1965	Combustion-Turbine	Gas	Peaking	---(C)	---	
	4	1965	Combustion-Turbine	Gas	Peaking	---(C)	---	---
Woodward	1	1963	Combustion-Turbine	Gas	Peaking	0.1%(B)	12.0	12.0
McClain(D)	1	2001	Combined Cycle	Gas	Base Load	59.8%	406.8	406.8
Total Generating Capability (all stations)								6,140.7

(A) 2004 Capacity Factor = 2004 Net Actual Generation / (2004 Net Maximum Capacity (Nameplate Rating in MWs) x Period Hours (8,760 Hours)).
(B) Peaking units, which are used when additional capacity is required, are also necessary to meet the Southwest Power Pool reserve margins.
(C) These units are currently inactive.
(D) The Company owns a 77 percent interest in the 520 MW McClain Plant.

At December 31, 2004, the Company's transmission system included: (i) 27 substations with a total capacity of approximately 7.2 million kilo Volt-Amps ("kVA") and approximately 3,969 structure miles of lines in Oklahoma; and (ii) two substations with a total capacity of approximately 1.5 million kVA and approximately 252 structure miles of lines in Arkansas. The Company's distribution system included: (i) 339 substations with a total capacity of approximately 9.9 million kVA, 22,567 structure miles of overhead lines, 1,941 miles of underground conduit and 7,868 miles of underground conductors in Oklahoma; and (ii) 33 substations with a total capacity of approximately 1.5 million kVA, 1,889 structure miles of overhead lines, 239 miles of underground conduit and 459 miles of underground conductors in Arkansas.

During the three years ended December 31, 2004, the Company's gross property, plant and equipment additions were approximately $745.7 million and gross retirements were approximately $99.6 million. These additions were provided by internally generated funds from operating cash flows, short-term borrowings from Energy Corp. (through a combination of bank borrowings and commercial paper) and permanent financings. The additions during this three-year period amounted to approximately 16.1 percent of total property, plant and equipment at December 31, 2004.

Item 3. Legal Proceedings.

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 Financial Statements. Except as set forth below and in Notes 12 and 13 of Notes to Financial Statements, management, after consultation with legal counsel, does not anticipate that liabilities arising out of currently pending or threatened lawsuits and claims will have a material adverse effect on the Company's financial position, results of operations or cash flows.

1. The City of Enid, Oklahoma ("Enid") through its City Council, notified the Company of its intent to purchase the Company's electric distribution facilities for Enid and to terminate the Company's franchise to provide electricity within Enid as of June 26, 1998. On August 22, 1997, the City Council of Enid adopted Ordinance No. 97-30, which in essence granted the Company a new 25-year franchise subject to approval of the electorate of Enid on November 18, 1997. In October 1997, 18 residents of Enid filed a lawsuit against Enid, the Company and others in the District Court of Garfield County, State of Oklahoma, Case No. CJ-97-829-01. Plaintiffs seek a declaration holding that (i) the Mayor of Enid and the City Council breached their fiduciary duty to the public and violated Article 10, Section 17 of the Oklahoma Constitution by allegedly "gifting" to the Company the option the city held to acquire the Company's electric system when the City Council approved the new franchise by Ordinance No. 97-30; (ii) the subsequent approval of the new franchise by the electorate of the City of Enid at

the November 18, 1997, franchise election cannot cure the alleged breach of fiduciary duty or the alleged constitutional violation; (iii) violations of the Oklahoma Open Meetings Act occurred and that such violations render the resolution approving Ordinance No. 97-30 invalid; (iv) the Company's support of the Enid Citizens' Against the Government Takeover was improper; (v) the Company has violated the favored nations clause of the existing franchise; and (vi) the City of Enid and the Company have violated the competitive bidding requirements found at 11 O.S. 35-201, et seq. Plaintiffs sought money damages against the Defendants under 62 O.S. 372 and 373. Plaintiffs alleged that the action of the City Council in approving the proposed franchise allowed the option to purchase the Company's property to be transferred to the Company for inadequate consideration. Plaintiffs demanded judgment for treble the value of the property allegedly wrongfully transferred to the Company. On October 28, 1997, another resident filed a similar lawsuit against the Company, Enid and the Garfield County Election Board in the District Court of Garfield County, State of Oklahoma, Case No. CJ-97-852-01. However, Case No. CJ-97-852-01 was dismissed without prejudice in December 1997. On December 8, 1997, the Company filed a Motion to Dismiss Case No. CJ-97-829-01 for failure to state claims upon which relief may be granted and no action has been taken on this motion for seven years. While the Company cannot predict the precise outcome of this proceeding, the Company believes at the present time that this lawsuit is without merit and intends to vigorously defend this case.

2. United States of America ex rel., Jack J. Grynberg v. Enogex Inc., Enogex Services Corporation and the Company. (United States District Court for the Western District of Oklahoma, Case No. CIV-97-1010-L.) United States of America ex rel., Jack J. Grynberg v. Transok Inc. et al. (United States District Court for the Eastern District of Louisiana, Case No. 97-2089; United States District Court for the Western District of Oklahoma, Case No. 97-1009M.). On June 15, 1999, the Company was served with Plaintiff's complaint, which is a qui tam action under the False Claims Act. Plaintiff Jack J. Grynberg, as individual relator on behalf of the United States Government, alleges: (i) each of the named defendants have improperly or intentionally mismeasured gas (both volume and British thermal unit content) purchased from federal and Indian lands which have resulted in the under-reporting and underpayment of gas royalties owed to the Federal Government; (ii) certain provisions generally found in gas purchase contracts are improper; (iii) transactions by affiliated companies are not arms-length; (iv) excess processing cost deduction; and (v) failure to account for production separated out as a result of gas processing. Grynberg seeks the following damages: (a) additional royalties which he claims should have been paid to the Federal Government, some percentage of which Grynberg, as relator, may be entitled to recover; (b) treble damages; (c) civil penalties; (d) an order requiring defendants to measure the way Grynberg contends is the better way to do so; and (e) interest, costs and attorneys' fees.

In qui tam actions, the United States Government can intervene and take over such actions from the relator. The Department of Justice, on behalf of the United States Government, decided not to intervene in this action.

Plaintiff filed over 70 other cases naming over 300 other defendants in various Federal Courts across the country containing nearly identical allegations. The Multidistrict Litigation Panel entered its order in late 1999 transferring and consolidating for pretrial purposes

approximately 76 other similar actions filed in nine other Federal Courts. The consolidated cases are now before the United States District Court for the District of Wyoming.

In October 2002, the Court granted the Department of Justice's motion to dismiss certain of Plaintiff's claims and issued an order dismissing Plaintiff's valuation claims against all defendants. Various procedural motions have been filed. Discovery is proceeding on limited jurisdictional issues as ordered by the Court. A hearing on the defendants' motions to dismiss for lack of subject matter jurisdiction, including public disclosure, original source and voluntary disclosure requirements is set for March 17 - 18, 2005.

The Company intends to vigorously defend this action. Since the case is in the early stages of motions and discovery, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company at this time.

3. *Will Price (Price I)* - On September 24, 1999, various subsidiaries of Energy Corp. were served with a class action petition filed in United States District Court, State of Kansas by Quinque Operating Company and other named plaintiffs, alleging mismeasurement of natural gas on non-federal lands. On April 10, 2003 the Court entered an order denying class certification. On May 12, 2003, Plaintiffs (now Will Price, Stixon Petroleum, Inc., Thomas F. Boles and the Cooper Clark Foundation, on behalf of themselves and other royalty interest owners) filed a motion seeking to file an amended petition and the court granted the motion on July 28, 2003. In this amended petition, the Company and Enogex Inc. were omitted from the case. Two subsidiaries of Enogex remain as defendants. The Plaintiffs' amended petition alleges that approximately 60 defendants, including two Enogex subsidiaries, have improperly measured natural gas. The amended petition reduces the claims to: (1) mismeasurement of volume only; (2) conspiracy, unjust enrichment and accounting; (3) a putative Plaintiffs' class of only royalty owners; and (4) gas measured in three specific states. Discovery on class certification is proceeding. A hearing on class certification issues is set for April 1, 2005.

Energy Corp. intends to vigorously defend this action. Since the case is in the early stages of motions and discovery, Energy Corp. is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to Energy Corp. at this time.

4. The Company has been sued by Kaiser-Francis Oil Company in District Court, Blaine County, Oklahoma. This case has been pending for more than 10 years. Plaintiff alleges that the Company breached the terms of numerous contracts covering approximately 60 wells by failing to purchase gas from Plaintiff in amounts set forth in the contracts. Plaintiff seeks $20.0 million in take-or-pay damages and $1.8 million in underpayment damages. Over the objection and unsuccessful appeal by the Company, Plaintiff has been permitted to amend its petition to include a claim based on theories of tort. Specifically, Plaintiff alleges, among other things, that the Company intentionally and tortuously interfered with contracts by falsifying documents, sponsoring false testimony and putting forward legal defenses, which are known by the Company to be without merit. If successful, Plaintiff believes that these theories could give Plaintiff a

basis to seek punitive damages. This lawsuit was stayed pending the outcome of an appeal that the Company filed in a similar case brought by Kaiser-Francis in Grady County.

In the Grady case, the plaintiff alleged that the Company breached the terms of several gas purchase contracts in amounts set forth in the contracts. In 2001, the district court rendered a verdict against the Company in the amount of approximately $8.0 million, including pre-judgment interest and attorneys' fees. The Company filed an appeal and on May 18, 2004, the Court of Appeals issued an opinion reversing the judgment and remanding for a new trial. The appellate court found that the trial court committed reversible error in rejecting a portion of the Company's interpretation of the commercial well provisions of the gas purchase contracts, and in failing to recognize issues of fact for the jury relating to the Company's contention regarding the correct initial reserve estimate on one of the natural gas wells, the Thiel No 1-9. In addition, the appellate court made rulings favorable to the Company relating to the statutory measure of damages, the effect of line pressure adjustment provisions in the contracts, and the admission of certain hearsay evidence. The appellate court made rulings favorable to Kaiser-Francis relating to the effect of royalty payment obligations on the amount of damages, the effect of the amount of reserves owned by Kaiser-Francis in the wells on the Company's gas purchase obligation, the propriety of the award of prejudgment interest, and the Company's liability for the payment of gross production taxes pertaining to the damages awarded. The appellate court returned an issue relating to the alleged effect of Kaiser-Francis's failure to make gas available for consideration by the trial court. Finally, the appellate court denied Kaiser-Francis's request for appeal-related attorney's fees and costs. On July 6, 2004, the Court of Appeals denied Kaiser-Francis's motion for rehearing. Both parties filed petitions for certiorari with the Oklahoma Supreme Court for the review of those portions of the appellate court's opinion unfavorable to each. The Oklahoma Supreme Court denied both parties' petitions for certiorari on January 10, 2005. Once the mandate issues from the Oklahoma Supreme Court, this case will be sent back to the District Court of Grady County for further proceedings consistent with the decision of the Court of Appeals. In the Blaine County case, once the mandate issues from the Oklahoma Supreme Court in the Grady County appeal, the parties will have 30 days to notify the trial judge in the District Court of Blaine County that the appeal is over. At that time, the trial judge is likely to lift the stay that has been in effect since June 3, 2002. The Company believes that, to the extent Plaintiff were successful on the merits of its claims of the Company's failure to take gas in either the Blaine County case or Grady County case, these amounts would be recoverable through its regulated electric rates. The claims related to tortuous conduct, which the Company believes at this time are without merit, would not appear to be recoverable in its electric rates.

5. The Company vs. Terra Tech, LLC, District Court of Oklahoma County, State of Oklahoma. Case No. CJ-2004-149. The Company filed suit against Terra Tech, LLC ("Terra Tech") alleging that Terra Tech fraudulently, and in breach of contract, submitted invoices for work not performed and materials not used. Terra Tech filed an answer containing a counterclaim against the Company. Defendant Terra Tech contends that the Company's actions constituted a breach of oral contract and failure to pay for work performed in an amount in excess of $10,000. Defendant Terra Tech also seeks attorney fees. The Company believes that recovery on the counterclaim by Terra Tech, if any, would be less than the Company's recovery

against Terra Tech. Discovery has been served on the defendant and there have been no scheduling deadlines or trial date yet.

Item 4. Submission of Matters to a Vote of Security Holders.

Under the reduced disclosure format permitted by General Instruction I(2)(c) of Form 10-K, the information otherwise required by this item has been omitted.

Executive Officers of the Registrant.

The following persons were Executive Officers of the Registrant as of February 25, 2005:

Name	Age	Title
Steven E. Moore	58	Chairman of the Board, President and Chief Executive Officer
Peter B. Delaney	51	Executive Vice President and Chief Operating Officer
James R. Hatfield	47	Senior Vice President and Chief Financial Officer
Jack T. Coffman	61	Senior Vice President - Power Supply
Steven R. Gerdes	48	Vice President - Utility Operations
Melvin H. Perkins, Jr.	56	Vice President - Transmission
Michael G. Davis	55	Vice President - Business Process
Donald R. Rowlett	47	Vice President and Controller
Deborah S. Fleming	49	Treasurer
Gary D. Huneryager	54	Internal Audit Officer
Carla D. Brockman	45	Corporate Secretary
Jerry A. Peace	42	Chief Risk and Compliance Officer

No family relationship exists between any of the Executive Officers of the Registrant. Messrs. Moore, Delaney, Hatfield, Davis, Rowlett, Huneryager and Peace, Ms. Fleming and Ms. Brockman are also officers of Energy Corp. Each Officer is to hold office until the Board of Directors meeting following the next Annual Meeting of Stockholders, currently scheduled for May 19, 2005.

The business experience of each of the Executive Officers of the Registrant for the past five years is as follows:

Name	Business Experience	
Steven E. Moore	2000 - Present:	Chairman of the Board, President and Chief Executive Officer of Energy Corp. and the Company
Peter B. Delaney	2004 - Present:	Executive Vice President and Chief Operating Officer of Energy

		Corp. and the Company
	2002 - 2004:	Executive Vice President, Finance and Strategic Planning - Energy Corp. and Chief Executive Officer - Enogex Inc.
	2001 - 2002:	Principal, PD Energy Advisors (consulting firm)
	2000 - 2001:	Managing Director, UBS Warburg (investment banking firm)
James R. Hatfield	2000 - Present:	Senior Vice President and Chief Financial Officer of Energy Corp. and the Company
	2000:	Senior Vice President, Chief Financial Officer and Treasurer of Energy Corp. and the Company
Jack T. Coffman	2000 - Present:	Senior Vice President - Power Supply of the Company
Steven R. Gerdes	2003 - Present:	Vice President - Utility Operations of the Company
	2000 - 2003:	Vice President - Shared Services of Energy Corp. and the Company

Name		Business Experience
Melvin H. Perkins, Jr.	2004 - Present:	Vice President - Transmission of the Company
	2002 - 2003:	Director - Transmission Policy of the Company
	2000 - 2002:	Manager, Power Delivery Operations of the Company
Michael G. Davis	2004 - Present:	Vice President - Business Process of Energy Corp. and the Company
	2002 - 2003:	Vice President - Process Management of the Company
	2000 - 2002:	Vice President - Marketing and Customer Care of the Company
Donald R. Rowlett	2000 - Present:	Vice President and Controller of Energy Corp. and the Company
Deborah S. Fleming	2003 - Present:	Treasurer of Energy Corp. and the Company
	2000 - 2003:	Assistant Treasurer - Williams Cos. Inc.
	2000:	Director of Corporate Finance - Williams Cos. Inc. (energy company)
Gary D. Huneryager	2002 - Present:	Internal Audit Officer of Energy Corp. and the Company
	2001 - 2002:	Assistant Internal Audit Officer of Energy Corp. and the Company
	2000 - 2001:	Service Line Director (Business Process Outsourcing) - Arthur Andersen LLP

Name		Business Experience
Carla D. Brockman	2002 - Present:	Corporate Secretary of Energy Corp. and the Company
	2002:	Assistant Corporate Secretary of Energy Corp. and the Company
	2000 - 2002:	Client Manager - Strategic Planning of Energy Corp. and the Company
Jerry A. Peace	2004 - Present:	Chief Risk and Compliance Officer of Energy Corp. and the Company

2002 - 2004:	Chief Risk Officer of Energy Corp. and the Company
2001 - 2002:	Director, Options Trading - Enogex Inc.
2000 - 2001:	Director, Structured Services - Enogex Inc.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

Currently, all of the Company's outstanding common stock is held by Energy Corp. Therefore, there is no public trading market for the Company's common stock.

Item 6. Selected Financial Data.

HISTORICAL DATA

	2004	2003	2002	2001	2000
SELECTED FINANCIAL DATA *(In millions)*					
Operating revenues	**$ 1,578.1**	$ 1,517.1	$ 1,388.0	$ 1,456.8	$ 1,453.6
Cost of goods sold	**914.5**	837.4	695.8	766.5	752.4
Gross margin on revenues	**663.6**	679.7	692.2	690.3	701.2
Other operating expenses	**471.6**	463.5	453.1	453.7	430.1
Operating income	**192.0**	216.2	239.1	236.6	271.1
Other income	**6.1**	0.8	0.7	1.1	0.1
Other expense	**2.7**	3.2	3.1	3.5	2.8
Net interest expense	**34.8**	38.2	39.0	43.6	45.7
Income tax expense	**53.0**	60.2	71.6	69.4	80.3
Net income	**$ 107.6**	$ 115.4	$ 126.1	$ 121.2	$ 142.4
Long-term debt	**$ 847.2**	$ 707.2	$ 710.5	$ 700.4	$ 702.6
Total assets	**$ 3,084.2**	$ 2,775.2	$ 2,659.9	$ 2,549.8	$ 2,548.1
CAPITALIZATION RATIOS (A)					
Stockholder's equity	**55.64%**	56.54%	56.00%	56.93%	56.91%
Long-term debt	**44.36%**	43.46%	44.00%	43.07%	43.09%
RATIO OF EARNINGS TO FIXED CHARGES (B)					
Ratio of earnings to fixed charges	**4.76**	5.11	5.41	4.80	5.16

(A) Capitalization ratios = [Stockholder's equity / (Stockholder's equity + Long-term debt)] and [Long-term debt / (Stockholder's equity + Long-term debt)].

(B) For purposes of computing the ratio of earnings to fixed charges, (1) earnings consist of pre-tax income plus fixed charges, less allowance for borrowed funds used during construction; and (2) fixed charges consist of interest on long-term debt, related amortization, interest on short-term borrowings and a calculated portion of rents considered to be interest.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Introduction

Oklahoma Gas and Electric Company (the "Company") generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas and is subject to regulation by the Oklahoma Corporation Commission ("OCC"), the Arkansas Public Service Commission ("APSC") and the Federal Energy Regulatory Commission ("FERC"). The Company is a wholly-owned subsidiary of OGE Energy Corp. ("Energy Corp.") which is an energy and energy services provider offering physical delivery and management of both electricity and natural gas primarily in the south central United States. The Company was incorporated in 1902 under the laws of the Oklahoma Territory and is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. The Company sold its retail gas business in 1928 and is no longer engaged in the gas distribution business.

Executive Overview

In early 2002, Energy Corp. 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, Energy Corp. recognized that immediate deregulation of the retail electric markets in Oklahoma and Arkansas was very unlikely and revised its business strategy. In the summer of 2004, Energy Corp. again reviewed its business strategy in light of significant changing market and regulatory trends such as the over supply of electric generation, the evolution of electric transmission markets and rules, the natural gas supply forecast, the sustained increase of natural gas commodity prices and the anticipated emergence of liquefied natural gas. Energy Corp. concluded that its existing business strategy of utilizing a diversified asset position was the proper course.

During 2004, the Company had several significant accomplishments including the completion of the acquisition of a 77 percent interest in the 520 megawatt ("MW") NRG McClain Station (the "McClain Plant") in July 2004 and the completion of a revolving credit agreement totaling $100 million in October 2004. Looking at 2005, the Company expects to file a rate case during the second quarter of 2005 to recover, among other things, its investment in, and the operating expenses of, the McClain Plant and expects new approved rates to be in effect by January 2006. Also, during 2005, the Company will work to advance its Customer Savings and Reliability Plan which provides for increased investment at the utility to improve reliability and meet load growth, replace infrastructure equipment and deploy newer technology that improves operational and environmental performance. Capacity payment savings from reduced cogeneration payments and fuel savings from the McClain Plant will be utilized to mitigate the price increases associated with these investments. For additional information regarding the McClain Plant acquisition and related regulatory matters, see Note 13 of Notes to Financial Statements. During 2005, the Company will also be focused on controlling and managing operating and maintenance expenses and will continue to analyze the cost structure of the Company's businesses ensuring consistency with the Company's business model. Overall, the

Company has a strong commitment to train and retain talented personnel so that both the Company and its employees are successful in improving the financial and operating performance of the Company.

Energy Corp.'s vision is to be a regional energy company focused on its regulated utility business and natural gas pipeline business that is recognized for operational excellence and financial performance. Energy Corp. intends to maintain the majority of its assets in the regulated utility business complemented by its natural gas pipeline business. Energy Corp.'s long-term financial goals include earnings growth of four to five percent on a normalized basis, a dividend payout ratio below 75 percent and an A- credit rating.

Energy Corp.'s business strategy is to continue maintaining the diversified asset position of the Company and its affiliate, Enogex Inc. and subsidiaries ("Enogex") so as to provide competitive energy products and services to customers primarily in the south central United States. Energy Corp. will focus on those products and services with limited or manageable commodity exposure. Energy Corp. intends for the Company to continue as a vertically integrated utility engaged in the generation, transmission and distribution of electricity and to represent over time approximately 70 percent of Energy Corp.'s consolidated assets. The remainder of Energy Corp.'s consolidated assets will be in Enogex's businesses. At December 31, 2004, the Company and Enogex represented approximately 63 percent and 36 percent, respectively, of Energy Corp.'s consolidated assets. The remaining one percent of Energy Corp.'s consolidated assets were primarily at the holding company. In addition to the incremental growth opportunities that Enogex provides, Energy Corp. believes that many of the risk management practices, commercial skills and market information available from Enogex provide value to all of Energy Corp.'s businesses subject to the evolving federal regulations of the FERC in regard to the operations of the wholesale power market. In addition, Oklahoma and Arkansas legislatures and utility commissions may propose changes from time to time that could subject utilities to market risk. Accordingly, Energy Corp. is applying risk management practices to all of its operations in an effort to mitigate the potential adverse effect of any future regulatory changes.

The Company has approximately 430 MWs of contracts with qualified cogeneration facilities and small power production producers' ("QF contracts") that will expire at the end of 2007, unless extended by the Company. In addition, effective September 1, 2004, the Company entered into a new 15-year power sales agreement for 120 MWs with PowerSmith Cogeneration Project, L.P. ("PowerSmith"). The Company will continue reviewing all of the supply alternatives to these expiring QF contracts that minimize the total cost of generation to its customers, including exercising its options (if applicable) to extend these QF contracts at pre-determined rates. Accordingly, the Company will continue to explore opportunities to build or buy power plants in order to serve its native load. As a result of the high volatility of current natural gas prices and the increase in natural gas prices, the Company will also assess the feasibility of constructing additional base load coal-fired units.

Forward-Looking Statements

Except for the historical statements contained herein, the matters discussed in the following discussion and analysis, including the discussion in "2005 Outlook", are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate", "believe", "estimate", "expect", "intend", "objective", "plan", "possible", "potential" and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including the availability of credit, actions of rating agencies and their impact on capital expenditures; the Company's and Energy Corp.'s ability to obtain financing on favorable terms; prices of electricity and natural gas; business conditions in the energy industry; competitive factors including the extent and timing of the entry of additional competition in the markets served by the Company; unusual weather; federal or state legislation and regulatory decisions (the proceeding currently pending before the OCC related to the Company's recovery of the costs billed to it by Enogex for gas transportation and storage services) and initiatives that affect cost and investment recovery, have an impact on rate structures and affect the speed and degree to which competition enters the Company's markets; environmental laws and regulations that may impact the Company's operations; changes in accounting standards, rules or guidelines; creditworthiness of suppliers, customers and other contractual parties; and other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission.

Overview

Summary of Operating Results

2004 compared to 2003. The Company reported net income of approximately $107.6 million as compared to approximately $115.4 million for the years ended December 31, 2004 and 2003, respectively. The decrease in net income during 2004 as compared to 2003 was primarily due to:

- cooler weather in the Company's service territory; and
- higher operating expenses.

These decreases to net income were partially offset by:

- gains from asset sales; and
- lower net interest expense, as described in more detail below.

2003 compared to 2002. The Company reported net income of approximately $115.4 million as compared to approximately $126.1 million for the years ended December 31, 2003 and 2002, respectively. The decrease in net income during 2003 as compared to 2002 was primarily due to:

- lower gross margins due to lower electric rates as a result of the $25 million electric rate reduction that went into effect in Oklahoma on January 6, 2003; and
- higher operating and maintenance expenses.

These decreases to net income were partially offset by:

- growth in the Company's service territory, as described in more detail below.

Regulatory Matters and Plant Acquisition

In November 2002, the OCC issued an order containing provisions of an agreed-upon settlement of the Company's rate case. The terms of this settlement included, among other things, a $25.0 million annual reduction in electric rates and a requirement for the Company to acquire 400 MWs of electric generation. The rate reduction went into effect January 6, 2003 and the acquisition of a 77 percent interest in the 520 MW McClain Plant was completed on July 9, 2004. The McClain Plant, located near Newcastle, Oklahoma, is a combined cycle unit consisting of two natural-gas fired combustion turbine generators combined with a steam turbine generator. The owner of the remaining 23 percent interest in the McClain Plant is the Oklahoma Municipal Power Authority. The Company operates the plant. The purchase price was approximately $160.0 million. The Company temporarily funded the McClain Plant acquisition with short-term borrowings from Energy Corp. On August 4, 2004, the Company issued $140.0 million of long-term debt to replace these short-term borrowings. Also, on August 9, 2004, Energy Corp. made a capital contribution to the Company of approximately $153.0 million. For additional information regarding the McClain Plant acquisition and related regulatory matters, see Note 13 of Notes to Financial Statements.

2005 Outlook

For 2005, Energy Corp.'s earnings guidance is $137 million to $147 million of net income, or $1.50 to $1.60 per share, assuming approximately 90.5 million average diluted shares outstanding. The 2005 outlook includes earnings guidance of $106 million to $110 million for the Company. In 2005, the Company plans to increase capital expenditures for electric system reliability upgrades. Additionally, funding for Energy Corp.'s pension plan is expected to be approximately $37.4 million in 2005, of which approximately $29.0 million is expected to be allocated to the Company. Expected 2005 net income assumes a 38.7 percent effective tax rate.

For 2005, the Company's earnings guidance is $106 million to $110 million. The Company assumes that margin growth approximating one to two percent will be more than offset by increased operating expenses and higher interest costs associated with the acquisition of the McClain Plant and capital expenditures for investment in the Company's generation, transmission and distribution system. The Company expects to increase capital expenditures to

approximately $248 million for electric system expansion and reliability upgrades in 2005. Key factors affecting the Company's 2005 net income will be the result of pending regulatory proceedings, weather, the Company's ability to control operating and maintenance expenses and customer growth. The Company has significant seasonality in its earnings. The Company typically shows minimal earnings or slight losses in the first and fourth quarters with a majority of earnings in the third quarter due to the seasonal nature of air conditioning demand. The earnings guidance further assumes no change in base rates and normal weather. The Company expects to file a rate case during the second quarter of 2005 to recover, among other things, its investment in, and the operating expenses of, the McClain Plant and expects new approved rates to be in effect by January 2006. The earnings guidance also assumes a recovery of the costs associated with the Enogex natural gas transportation and storage services at a level consistent with a recent recommendation by the administrative law judge overseeing this proceeding. On October 22, 2004, the administrative law judge overseeing the proceeding recommended approximately $41.9 million annual demand fee recovery with the Company refunding to its customers any amounts collected in excess of this amount. If this recommendation is ultimately accepted, the Company believes its refund obligation would be approximately $6.9 million at December 31, 2004, which the Company does not believe is material in light of previously established reserves. An OCC order in this case is expected in the first quarter of 2005. There can be no guarantee that the OCC will approve the $41.9 million annual demand fee recovery recommended by the administrative law judge. See Note 13 of Notes to Financial Statements for a further discussion of this matter.

Results of Operations

The following discussion and analysis presents factors which affected the Company's results of operations for the years ended December 31, 2004, 2003 and 2002 and the Company's financial position at December 31, 2004 and 2003. The following information should be read in conjunction with the Financial Statements and Notes thereto. Known trends and contingencies of a material nature are discussed to the extent considered relevant.

(In millions)	**2004**	2003	2002
Operating income	**$ 192.0**	$ 216.2	$ 239.1

Net income	**$ 107.6**	$ 115.4	$ 126.1

In reviewing its operating results, the Company believes that it is appropriate to focus on operating income as reported in its Statements of Income as operating income indicates the ongoing profitability of the Company excluding unusual or infrequent items, the cost of capital and income taxes.

OG&E

(Dollars in millions)	**2004**	2003	2002
Operating revenues	**$ 1,578.1**	$ 1,517.1	$ 1,388.0
Fuel	**645.4**	544.5	435.8
Purchased power	**269.1**	292.9	260.0
Gross margin on revenues	**663.6**	679.7	692.2
Other operating and maintenance	**301.9**	294.8	282.9
Depreciation	**122.7**	121.8	123.1
Taxes other than income	**47.0**	46.9	47.1
Operating income	**$ 192.0**	$ 216.2	$ 239.1
Operating revenues by classification			
Residential	**$ 611.4**	$ 601.4	$ 557.6
Commercial	**389.9**	372.5	346.9
Industrial	**326.7**	293.4	258.6
Public authorities	**158.5**	146.1	135.5
Sales for resale	**57.0**	57.7	48.2
Provision for refund on gas transportation and storage case	**(6.9)**	---	---
Other	**40.7**	41.9	34.9
System sales revenues	**1,577.3**	1,513.0	1,381.7
Off-system sales revenues	**0.8**	4.1	6.3
Total operating revenues	**$ 1,578.1**	$ 1,517.1	$ 1,388.0
MWH (A) sales by classification (in millions)			
Residential	**7.9**	8.2	8.0
Commercial	**5.7**	5.8	5.8
Industrial	**7.0**	6.8	6.6
Public authorities	**2.7**	2.7	2.7
Sales for resale	**1.4**	1.5	1.5
System sales	**24.7**	25.0	24.6
Off-system sales	**0.1**	0.1	0.3
Total sales	**24.8**	25.1	24.9
Number of customers	**735,008**	725,470	718,513
Average cost of energy per KWH (B) - cents			
Fuel	**2.887**	2.454	1.897
Fuel and purchased power	**3.436**	3.128	2.614
Degree days (C)			
Heating			
Actual	**3,114**	3,488	3,753
Normal	**3,650**	3,631	3,634
Cooling			
Actual	**1,839**	1,898	1,847
Normal	**1,911**	1,911	1,911

(A)Megawatt-hour
(B)Kilowatt-hour
(C)Degree days are calculated as follows: The high and low degrees of a particular day are added together and then averaged. If the calculated average is above 65 degrees, then the difference between the calculated average and 65 is expressed as cooling degrees days, with each degree of difference equaling one cooling degree day. If the calculated average is below 65 degrees, than the difference between the calculated average and 65 is expressed as heating degree days, with each degree of difference equaling one heating degree day. The daily calculations are then totaled for the particular reporting period.

2004 compared to 2003. The Company's operating income decreased approximately $24.2 million or 11.2 percent in 2004 as compared to 2003. The decrease in operating income was primarily attributable to:

- o lower gross margins on revenues ("gross margin") due to cooler weather in the Company's service territory;
- o lower margins related to sales to wholesale customers;
- o the timing of fuel recoveries; and
- o higher operating expenses.

These decreases in operating income were partially offset by:

- o growth in the Company's service territory.

Gross margin, which is operating revenues less cost of goods sold, was approximately $663.6 million in 2004 as compared to approximately $679.7 million in 2003, a decrease of approximately $16.1 million or 2.4 percent. The gross margin decreased primarily due to:

- o cooler weather in the Company's service territory which reduced the gross margin by approximately $15.7 million;
- o lower margins related to sales to wholesale customers primarily resulting from reduced sales of power under a new wholesale contract with an existing customer which reduced the gross margin by approximately $3.2 million; and
- o the timing of fuel recoveries which decreased the gross margin by approximately $1.7 million.

These decreases in gross margin were partially offset by:

- o growth in the Company's service territory which increased the gross margin by approximately $4.9 million.

Cost of goods sold for the Company consists of fuel used in electric generation and purchased power. Fuel expense was approximately $645.4 million in 2004 as compared to approximately $544.5 million in 2003, an increase of approximately $100.9 million or 18.5 percent. The increase was primarily due to an increase in the average cost of fuel per kwh, primarily due to higher natural gas prices despite lower mwh sales. The Company's electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for the Company and its customers. In 2004, the Company's fuel mix was 70 percent coal and 30 percent natural gas as compared to 77 percent coal and 23 percent natural gas in 2003. Though the Company has a higher installed capability of generation from natural gas units of 59 percent, it has been more economical to generate electricity for our customers with lower priced coal. Purchased power costs were approximately $269.1 million in 2004 as compared to approximately $292.9 million in 2003, a decrease of approximately $23.8 million or 8.1 percent. The decrease was primarily due to the

Company's acquisition of the McClain Plant in July 2004 and the termination of power purchase contracts in December 2003 and August 2004.

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 the Company's customers through automatic fuel adjustment clauses. While the regulatory mechanisms for recovering fuel costs differ in Oklahoma, Arkansas and the FERC, in each jurisdiction the costs are passed through to customers and are intended to provide neither an ultimate benefit nor detriment to the Company. 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 the Company pays to Enogex. See Note 13 of Notes to Financial Statements for a discussion of current proceedings at the OCC regarding the Company's gas transportation and storage contract with Enogex.

Other operating and maintenance expenses were approximately $301.9 million in 2004 as compared to approximately $294.8 million in 2003, an increase of approximately $7.1 million or 2.4 percent. The increase in other operating and maintenance expenses was primarily due to:

- o increased outside services expense of approximately $17.9 million, primarily due to higher expenses for infrastructure projects in the fourth quarter of 2004, many of which were postponed from earlier in 2004;
- o increased materials and supplies expense of approximately $1.8 million; and
- o increased liability insurance expense of approximately $0.9 million due to increased insurance premiums.

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

- o lower salaries and wages expense of approximately $6.8 million and lower pension and benefit expense of approximately $6.6 million primarily due to more projects on which the costs are capitalized and are not being expensed currently.

Depreciation expense was approximately $122.7 million in 2004 as compared to approximately $121.8 million in 2003, an increase of approximately $0.9 million or 0.7 percent, primarily due to a higher level of depreciable plant. Also, another factor affecting 2004 results was an overall increase of approximately $3.8 million in the reserves related to litigation.

2003 compared to 2002. The Company's operating income decreased approximately $22.9 million or 9.6 percent in 2003 as compared to 2002. The decrease in operating income was primarily attributable to:

- o lower electric rates as a result of the $25 million electric rate reduction that went into effect in Oklahoma on January 6, 2003;
- o weaker weather-related demand;
- o lower sales to other utilities and power marketers ("off-system sales"); and

- o higher other operating and maintenance expenses.

These decreases in operating income were partially offset by:

- o growth in the Company's service territory.

Gross margin was approximately $679.7 million in 2003 as compared to approximately $692.2 million in 2002, a decrease of approximately $12.5 million or 1.8 percent. The gross margin decreased primarily due to:

- lower electric rates as a result of the $25 million electric rate reduction that went into effect in Oklahoma on January 6, 2003, which reduced the gross margin by approximately $24.8 million;
- weaker weather-related demand which reduced the gross margin by approximately $2.0 million; and
- lower off-system sales which reduced the gross margin by approximately $1.9 million as off-system sales can vary based upon the supply and demand needs on the Company's generation system and the market for off-system sales.

These decreases in gross margin were partially offset by:

- growth in the Company's service territory which increased the gross margin by approximately $17.5 million.

Fuel expense was approximately $544.5 million in 2003 as compared to approximately $435.8 million in 2002, an increase of approximately $108.7 million or 24.9 percent. The increase was due to a 29.4 percent increase in the average cost of fuel per kwh, primarily due to higher natural gas prices and higher mwh sales. The Company's electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for the Company and its customers. In 2003, the Company's fuel mix was 77 percent coal and 23 percent natural gas. Purchased power costs were approximately $292.9 million in 2003 as compared to approximately $260.0 million in 2002, an increase of approximately $32.9 million or 12.7 percent. The increase was primarily due to approximately a 28.2 percent increase in the volume of energy purchased primarily due to economic purchases.

Other operating and maintenance expenses were approximately $294.8 million in 2003 as compared to approximately $282.9 million in 2002, an increase of approximately $11.9 million or 4.2 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher pension and benefit expenses of approximately $10.7 million due to the general upward trend in these costs; and
- costs of approximately $5.4 million incurred during the first quarter of 2002 in connection with the severe January 2002 ice storm being reported as a regulatory asset as these 2002 expenditures, incurred by field service personnel, would normally have been charged to maintenance expenses in 2002.

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

- lower uncollectibles expense of approximately $3.5 million due to improved collection efforts.

Depreciation expense was approximately $121.8 million in 2003 as compared to approximately $123.1 million in 2002, a decrease of approximately $1.3 million or 1.1 percent, primarily due to a change made in the depreciation rate of production plant in 2003 as required by the settlement of the Company's rate case in November 2002.

Other Income and Expense, Interest Expense and Income Tax Expense

2004 compared to 2003. Other income includes, among other things, contract work performed by the Company, non-operating rental income, gain on the sale of assets and miscellaneous non-operating income. Other income was approximately $6.1 million in 2004 as compared to approximately $0.8 million in 2003, an increase of approximately $5.3 million. The increase in other income was primarily due to:

- a realized gain of approximately $3.2 million from the sale of the Company's interests in its natural gas producing properties;
- increased allowance for equity funds used during construction in 2004 of approximately $0.9 million;
- a realized gain of approximately $0.6 million from the repurchase of outstanding heat pump loans; and
- a realized gain of approximately $0.3 million from the sale of land and buildings near the Company's principal executive offices.

Other expense includes, among other things, expenses from the losses on the sale of assets, miscellaneous charitable donations, expenditures for certain civic, political and related activities and miscellaneous deductions. Other expense was approximately $2.7 million in 2004 as compared to approximately $3.2 million in 2003, a decrease of approximately $0.5 million or 15.6 percent. The decrease in other expense was primarily due to a loss of approximately $0.4 million from the sale of miscellaneous assets.

Net interest expense includes interest income, interest expense and other interest charges. Net interest expense was approximately $34.8 million in 2004 as compared to approximately $38.2 million in 2003, a decrease of approximately $3.4 million or 8.9 percent. This decrease in net interest expense was primarily due to:

- an increase in interest income of approximately $1.7 million due to the interest portion of an income tax refund related to prior periods;
- a reduction in interest expense of approximately $1.1 million due to an increase in the allowance for borrowed funds used during construction; and

- lower interest expense to Energy Corp. of approximately $0.7 million due to the Company having lower average borrowings outstanding from Energy Corp. in 2004.

Income tax expense was approximately $53.0 million in 2004 as compared to approximately $60.2 million in 2003, a decrease of approximately $7.2 million or 12.0 percent. The decrease in income tax expense was primarily due to:

- lower pre-tax income for the Company; and
- the recognition of additional Oklahoma state tax credits of approximately $2.0 million during 2004.

2003 compared to 2002. Net interest expense was approximately $38.2 million in 2003 as compared to approximately $39.0 million in 2002, a decrease of approximately $0.8 million or 2.1 percent. This decrease in net interest expense was primarily due to a reduction in interest expense of approximately $0.7 million related to lower interest rates on outstanding debt achieved from entering into an interest rate swap agreement.

Income tax expense was approximately $60.2 million in 2003 as compared to approximately $71.6 million in 2002, a decrease of approximately $11.4 million or 15.9 percent. The decrease in income tax expense was primarily due to:

- lower pre-tax income for the Company; and
- a greater deduction for the Company's Employee Stock Ownership Plan dividends in 2003, which reduced taxable income as compared to 2002;

Financial Condition

The balance of Accounts Receivable – Customers was approximately $91.7 million and $123.1 million at December 31, 2004 and 2003, respectively, an increase of approximately $31.4 million or 25.5 percent. The decrease was primarily due to improved collection efforts.

The balance of Advances to Parent was approximately $26.5 million and $51.8 million at December 31, 2004 and 2003, respectively, a decrease of approximately $25.3 million or 48.8 percent. The decrease was primarily due to commercial paper issued by the Company in 2003 in anticipation of the completion of the McClain Plant acquisition. Due to a delay in the completion of the McClain Plant acquisition, the Company transferred these funds to Energy Corp. for investment during the fourth quarter of 2003. Energy Corp. repaid these advances during the first quarter of 2004.

The balance of Fuel Clause Under Recoveries was approximately $54.3 million at December 31, 2004. The balance of Fuel Clause Over Recoveries (net of Fuel Clause Under Recoveries) was approximately $28.4 million at December 31, 2003. The increase in fuel clause under recoveries was due to under recoveries from the Company's customers as the Company's cost of fuel exceeded the amount billed during 2004. The cost of fuel subject to recovery through

the fuel clause mechanism was approximately $2.43 per million British thermal unit ("MMBtu") in December 2004, and was approximately $1.21 per MMBtu in December 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 above the baseline charge for fuel and over recovers fuel cost when prices decline below the baseline charge for fuel. Provisions in the fuel clauses allow the Company to amortize under or over recovery. The Company expects to recover the fuel clause under recoveries during 2005.

The balance of Recoverable Take or Pay Gas Charges was approximately $17.0 million and $32.5 million at December 31, 2004 and 2003, respectively, a decrease of approximately $15.5 million or 47.7 percent. Approximately $21.0 million and $32.5 million have been recorded at December 31, 2004 and 2003, respectively, in the Provision for Payments of Take or Pay Gas classified as Current Liabilities and Deferred Credits and Other Liabilities in the Balance Sheets. These amounts represent the Company's estimate of the maximum amount that it could be obligated to pay under certain take-or-pay contracts. The Company believes that it is entitled to recover any such amounts from its customers through its regulatorily approved automatic fuel adjustment clauses or other regulatory mechanisms.

The balance of Prepaid Benefit Obligation was approximately $67.2 million and $37.5 million at December 31, 2004 and 2003, respectively, an increase of approximately $29.7 million or 79.2 percent. The increase was primarily due to Energy Corp. funding its pension plan during the second and third quarters of 2004, of which a portion was allocated to the Company, partially offset by pension accruals being credited to the prepaid benefit obligation.

The balance of Short-Term Debt was approximately $50.0 million at December 31, 2003 primarily due to the planned acquisition of the McClain Plant by the end of 2003. In December 2003, the Company issued commercial paper in anticipation of the planned acquisition of the McClain Plant. Due to a delay in the completion of the McClain Plant acquisition, the Company transferred these funds to Energy Corp. for investment during the fourth quarter of 2003. Due to a delay in the completion of the McClain Plant acquisition, Energy Corp. repaid the outstanding advances and the Company used these funds to repay the outstanding commercial paper balance during the first quarter of 2004. At December 31, 2004, there was no short-term debt outstanding.

The balance of Accounts Payable – Other was approximately $93.0 million and $57.7 million at December 31, 2004 and 2003, respectively, an increase of approximately $35.3 million or 61.2 percent. The increase was primarily due to an increase in natural gas prices and volumes.

The balance of Long-Term Debt was approximately $847.2 million and $707.2 million at December 31, 2004 and 2003, respectively, an increase of approximately $140.0 million or 19.8 percent. The increase was primarily due to the issuance of $140.0 million of long-term debt in August 2004 by the Company to replace the short-term borrowings initially issued to finance the McClain Plant acquisition.

The balance of Accrued Pension and Benefit Obligations was approximately $155.5 million and $134.8 million at December 31, 2004 and 2003, respectively, an increase of approximately $20.7 million or 15.4 percent. The increase was primarily due to an increase in the liability associated with Energy Corp.'s pension plan, of which a portion was allocated to the Company, due to a decrease in the assumed discount rate. See Note 11 of Notes to Financial Statements for a further discussion.

Off-Balance Sheet Arrangements

Off-balance sheet arrangements include any transactions, agreements or other contractual arrangements to which an unconsolidated entity is a party and under which the Company has: (i) any obligation under a guarantee contract having specific characteristics as defined in Financial Accounting Standards Board ("FASB") Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others"; (ii) a retained or contingent interest in assets transferred to an unconsolidated entity or similar arrangement that serves as credit, liquidity or market risk support to such entity for such assets; (iii) any obligation, including a contingent obligation, under a contract that would be accounted for as a derivative instrument but is indexed to the Company's own stock and is classified in stockholder's equity in the Company's balance sheet; or (iv) any obligation, including a contingent obligation, arising out of a variable interest as defined in FASB Interpretation No. 46, "Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51," in an unconsolidated entity that is held by, and material to, the Company, where such entity provides financing, liquidity, market risk or credit risk support to, or engages in leasing, hedging or research and development services with, the Company. The Company has the following off-balance sheet arrangements.

Heat Pump Loans

Prior to January 1, 2004, the Company had a heat pump loan program that allowed qualifying customers to obtain a loan from the Company to purchase a heat pump. In October 1998, the Company sold approximately $25.0 million of its heat pump loans in a securitization transaction through OGE Consumer Loan LLC. During the second quarter of 2004, the Company repurchased the outstanding heat pump loan balance of approximately $0.1 million. The Company recorded a gain of approximately $0.6 million in the third quarter of 2004 related to this transaction. Effective November 19, 2004, the Company dissolved OGE Consumer Loan LLC. In November 1999, the Company sold approximately $12.7 million of its heat pump loans in a securitization transaction through OGE Consumer Loan II LLC. In October 2004, the Company repurchased the outstanding heat pump loan balance of approximately $1.1 million. The Company recorded a loss of less than $0.1 million in the fourth quarter of 2004 related to this transaction. Effective January 31, 2005, the Company dissolved OGE Consumer Loan II LLC. Effective January 1, 2004, the Company discontinued issuing heat pump loans to customers and all new heat pump loans are now processed and managed by a third party. The Company continues to service the heat pump loans it recently repurchased in 2004 in addition to the heat pump loans the Company sold during 2003. The finance rate on the heat pump loans was based upon market rates and was reviewed and updated periodically. The interest rate was

11.55 percent at December 31, 2003. The Company's heat pump loan balance was approximately $1.3 million and $1.4 million at December 31, 2004 and 2003, respectively and is included in Accounts Receivable – Customers, Net in the Balance Sheets.

The Company sold approximately $8.5 million of its heat pump loans in December 2002 as part of a securitization transaction through OGE Consumer Loan 2002, LLC. The following table contains information related to this securitization.

	2002
Date heat pump loans sold	December 2002
Total amount of heat pump loans sold (in millions)	$ 8.5
Heat pump loan balance at December 31, 2004 (in millions)	$ 3.9
Note interest rate	5.25%
Base servicing fee rate (paid monthly)	0.375%
Trustee/custodian fees (paid quarterly) (in whole dollars)	$ 1,250
Owner trustee fees (paid annually) (in whole dollars)	$ 4,000
Sole director's fee (paid quarterly) (in whole dollars)	$ 1,125
Loss exposure by securitization issue (in millions)	$ 0.6

Railcar Leases

At December 31, 2004, the Company has a noncancellable operating lease which has purchase options covering 1,464 coal hopper railcars to transport coal from Wyoming to the Company's coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through the Company's tariffs and automatic fuel adjustment clauses. At the end of the lease term which is March 31, 2006, the Company has the option to purchase the railcars at a stipulated fair market value. If the Company chose not to purchase the railcars and the actual value of the railcars was less than the stipulated fair market value, the Company would be responsible for the difference in those values up to a maximum of approximately $36 million. The Company expects to enter into a new lease agreement for railcars effective April 1, 2006, which should negate any financial exposure under the current lease agreement. The Company is also required to maintain the railcars it has under lease to transport coal from Wyoming and has entered into agreements with Progress Rail Services and WATCO, both of which are non-affiliated companies, to furnish this maintenance.

Liquidity and Capital Requirements

The Company's primary needs for capital are related to replacing or expanding existing facilities in its electric utility business. Other working capital requirements are primarily related to maturing debt, operating lease obligations, hedging activities and delays in recovering unconditional fuel purchase obligations. The Company generally meets its cash needs through a combination of internally generated funds, short-term borrowings from Energy Corp. (through a combination of bank borrowings and commercial paper) and permanent financings.

Capital requirements and future contractual obligations estimated for the next five years and beyond are as follows:

(In millions)	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
Capital expenditures including AFUDC (A)	$ 647.7	$ 235.7	$ 412.0	N/A	N/A
Maturities of long-term debt	847.2	109.9	---	$ ---	$ 737.3
Interest payments on long-term debt	802.8	42.4	72.4	72.4	615.6
Pension funding obligations	96.0	29.0	47.5	19.5	N/A
Total capital requirements	2,393.7	417.0	531.9	91.9	1,352.9
Operating lease obligations					
Railcars	51.7	5.4	10.7	10.7	24.9
Other purchase obligations and commitments					
Cogeneration capacity payments	465.6	99.5	194.2	171.9	N/A
Fuel minimum purchase commitments	907.0	170.8	319.0	251.7	165.5

Total other purchase obligations and commitments	1,372.6	270.3	513.2	423.6	165.5
Total capital requirements, operating lease obligations and other purchase obligations and commitments	3,818.0	692.7	1,055.8	526.2	1,543.3
Amounts recoverable through automatic fuel adjustment clause (B)	(1,424.3)	(275.7)	(523.9)	(434.3)	(190.4)
Total, net	$ 2,393.7	$ 417.0	$ 531.9	$ 91.9	$ 1,352.9

(A) Under current environmental laws and regulations, the Company may be required to spend additional capital expenditures on its coal-fired plants. These expenditures would not begin until the year 2008. The amounts and timing of these expenditures is uncertain at the present time.
(B) Includes expected recoveries of costs incurred for the Company's railcar operating lease obligations and the Company's unconditional fuel purchase obligations.
N/A – not applicable

Variances in the actual cost of fuel used in electric generation (which includes the operating lease obligations for the Company's railcar leases shown above) and certain purchased power costs, as compared to the fuel component included in the cost-of-service for ratemaking, are passed through to the Company's customers through automatic fuel adjustment clauses. Accordingly, while the cost of fuel related to operating leases and the vast majority of unconditional fuel purchase obligations of the Company noted above may increase capital requirements, such costs are recoverable through automatic fuel adjustment clauses and have little, if any, impact on net capital requirements and future contractual obligations. The automatic fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC. The Company currently has pending before the OCC an application to recover the costs of gas transportation and storage services provided to it by Enogex pursuant to the contract between the Company and Enogex. An adverse decision by the OCC could result in the Company having to refund previously collected amounts. See Note 13 of Notes to Financial Statements for a further discussion.

2004 Capital Requirements and Financing Activities

Total capital requirements, consisting of capital expenditures, interest payments on long-term debt and pension funding obligations, were approximately $480.6 million in 2004. There were no contractual obligations, net of recoveries through automatic fuel adjustment clauses in 2004. The total net capital requirements and contractual obligations were approximately $480.6 million in 2004. Approximately $4.8 million of the 2004 capital requirements were to comply with environmental regulations. This compares to net capital requirements of approximately $222.8 million and net contractual obligations of approximately $2.0 million totaling approximately $224.8 million in 2003, of which approximately $6.4 million was to comply with environmental regulations. During 2004, the Company's sources of capital were internally generated funds from operating cash flows, short-term borrowings from Energy Corp. (through a combination of bank borrowings and commercial paper), issuance of long-term debt and proceeds from the sale of assets. Energy Corp. uses its commercial paper to fund changes in working capital and as an interim source of financing capital expenditures until permanent financing is arranged. Changes in working capital reflect the seasonal nature of the Company's business, the revenue lag between billing and collection for customers and fuel inventories. See "Financial Condition" for a discussion of significant changes in net working capital requirements as it pertains to operating cash flow and liquidity.

Issuance of Long-Term Debt

In August 2004, the Company issued $140.0 million of long-term debt. The proceeds were used to replace a portion of the short-term borrowings initially used to fund a portion of the McClain Plant acquisition in July 2004. This debt has a maturity date of August 1, 2034 and an interest rate of 6.50 percent.

Long-term Debt Maturities

Maturities of the Company's long-term debt during the next five years consist of $110.0 million in 2005; however, in the Statement of Capitalization at December 31, 2004, no amount is shown as Long-Term Debt Due Within One Year. The Company plans to refinance this amount and the Company believes they have the ability to do so as Energy Corp. and the Company entered into new five-year revolving credit agreements in October 2004 in an amount up to $550 million which could be utilized to temporarily finance these notes when they mature in October 2005.

Interest Rate Swap Agreement

Fair Value Hedge

At December 31, 2004 and 2003, the Company had one outstanding interest rate swap agreement that qualified as a fair value hedge 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. The objective of this interest rate swap 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. This interest rate swap qualified as a fair value hedge under Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, and met all of the requirements for a determination that there was no ineffective portion as allowed by the shortcut method under SFAS No. 133.

At December 31, 2004 and 2003, the fair values pursuant to the interest rate swap were approximately $3.9 million and $4.0 million, respectively, and the hedge was classified as Deferred Charges and Other Assets – Price Risk Management in the Balance Sheets. A corresponding net increase of approximately $3.9 million and $4.0 million was reflected in Long-Term Debt at December 31, 2004 and 2003, respectively, as this fair value hedge was effective at December 31, 2004 and 2003.

Future Capital Requirements

Capital Expenditures

The Company's current 2005 to 2007 construction program includes continued investment in system and transmission upgrades that is part of the Company's Customer Savings and Reliability Plan. The Company has approximately 430 MWs of QF contracts that will expire at the end of 2007, unless extended by the Company. In addition, effective September 1, 2004, the Company entered into a new 15-year power sales agreement for 120 MWs with PowerSmith. The Company will continue reviewing all of the supply alternatives to these expiring QF contracts that minimize the total cost of generation to its customers, including exercising its options (if applicable) to extend these QF contracts at pre-determined rates. Accordingly, the Company will continue to explore opportunities to build or buy power plants in order to serve its native load. As a result of the high volatility of current natural gas prices and the increase in natural gas prices, the Company will also assess the feasibility of constructing additional base load coal-fired units. See Note 13 of Notes to Financial Statements for a description of the new PowerSmith QF contract.

To reliably meet the increased electricity needs of the Company's customers during the foreseeable future, the Company will continue to invest to maintain the integrity of the delivery system. Approximately $5.3 million of the Company's capital expenditures budgeted for 2005 are to comply with environmental laws and regulations.

Pension and Postretirement Benefit Plans

During 2004, actual asset returns for Energy Corp.'s defined benefit pension plan were positively affected by growth in the equity markets; however, the growth in 2004 was not as strong as the growth in the equity markets in 2003. Approximately 62 percent of the pension plan assets are invested in listed common stocks with the balance invested in corporate debt and U.S. Government securities. In 2004, asset returns on the pension plan were approximately 12.51 percent as compared to approximately 22.76 percent in 2003. During the same time,

corporate bond yields, which are used in determining the discount rate for future pension obligations, have continued to decline.

Energy Corp.'s contributions to the pension plan increased from approximately $50.0 million in 2003 to approximately $69.0 million in 2004, of which approximately $38.8 million and $54.5 million were allocated to the Company in 2003 and 2004, respectively. This increase was necessitated by the lower investment returns on assets and lower discount rates used to value the accumulated pension benefit obligations. During 2005, Energy Corp. plans to contribute approximately $37.4 million to the pension plan, of which approximately $29.0 million is expected to be allocated to the Company. The level of funding is dependent on returns on plan assets and future discount rates. Higher returns on plan assets and increases in discount rates will reduce funding requirements to the plan.

As discussed in Note 11 of Notes to Financial Statements, in 2000 Energy Corp. made several changes to its pension plan, including the adoption of a cash balance benefit feature for employees hired after January 31, 2000. The cash balance plan may provide lower post-employment pension benefits to employees, which could result in less pension expense being recorded. Over the near term, Energy Corp.'s cash requirements for the plan are not expected to be materially different than the requirements existing prior to the plan changes. However, as the population of employees included in the cash balance plan feature increases, Energy Corp.'s cash requirements should decrease and will be much less sensitive to changes in discount rates.

During 2004 and 2003, Energy Corp. made contributions to the pension plan and the restoration of retirement income plan that exceeded amounts previously recognized as net periodic pension expense and recorded a net prepaid benefit obligation at December 31, 2004 and 2003 of approximately $92.0 million and $55.7 million, respectively, of which approximately $67.0 million and $37.5 million, respectively, were allocated to the Company. At December 31, 2004 and 2003, Energy Corp.'s projected pension benefit obligation exceeded the fair value of the pension plan assets and the restoration of retirement income plan assets by approximately $123.3 million and $131.8 million, respectively, of which approximately $105.9 million and $117.6 million, respectively, were allocated to the Company. As a result of recording a prepaid benefit obligation and having a funded status where the projected benefit obligations exceeded the fair value of plan assets, provisions of SFAS No. 87, "Employers' Accounting for Pensions," required the recognition of an additional minimum liability in the amount of approximately $156.6 million and $137.6 million, respectively, for Energy Corp., of which approximately $136.3 million and $122.8 million, respectively, were allocated to the Company at December 31, 2004 and 2003. The offset of this entry was an intangible asset and Accumulated Other Comprehensive Income, net of a deferred tax asset; therefore, this adjustment did not impact the results of operations in 2004 or 2003 and did not require a usage of cash and is therefore excluded from the Statements of Cash Flows. The amount recorded as an intangible asset equaled the unrecognized prior service cost with the remainder recorded in Accumulated Other Comprehensive Income. The amount in Accumulated Other Comprehensive Income represents a net periodic pension cost to be recognized in the Statements of Income in future periods.

Security Ratings

	Moody's	Standard & Poor's	Fitch's
Company Senior Notes	A2	BBB+	AA-

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.

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

Management expects that internally generated funds, funds received from Energy Corp. (from proceeds from the sales of its common stock pursuant to Energy Corp.'s Automatic Dividend Reinvestment and Stock Purchase Plan) and long and short-term debt will be adequate over the next three years to meet anticipated capital expenditures, operating needs, payment of dividends and maturities of long-term debt. As discussed below, the Company utilizes short-term borrowings from Energy Corp. (through a combination of bank borrowings and commercial paper) to satisfy temporary working capital needs and as an interim source of financing capital expenditures until permanent financing is arranged.

Short-Term Debt

The following table shows Energy Corp.'s and the Company's lines of credit in place and available cash at January 31, 2005. At January 31, 2005, Energy Corp.'s short-term borrowings consisted of commercial paper.

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

Entity	Amount Available	Amount Outstanding	Maturity
Energy Corp.	$ 15.0	$ ---	April 6, 2005
The Company	100.0	---	October 20, 2009 (B)
Energy Corp. (A)	450.0	---	October 20, 2009 (B)
	565.0	---	
Cash	14.9	N/A	N/A
Total	$ 579.9	$ ---	

(A) This line of credit is used to back up a maximum of $300.0 million of Energy Corp.'s commercial paper borrowings, which were approximately $187.6 million at January 31, 2005.
(B) Each of the new credit facilities has a five-year term with two options to extend the term for one year.

On October 20, 2004, Energy Corp. and the Company entered into revolving credit agreements totaling $550 million. These agreements include two separate credit facilities, one

for Energy Corp. in an amount up to $450 million and one for the Company in an amount up to $100 million. Each of the new credit facilities has a five-year term with two options to extend the term for one year. Planned uses of the revolving credit include working capital needs, back-up for Energy Corp.'s commercial paper program, the issuance of letters of credit and for general corporate purposes.

Energy Corp.'s and the Company's ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade. Their respective back-up lines of credit contain rating grids that require annual fees and borrowing rates to increase if they suffer an adverse ratings impact. The impact of any future downgrades would result in an increase in the cost of short-term borrowings but would not result in any defaults or accelerations as a result of the rating changes.

Unlike Energy Corp. and Enogex, the Company must obtain regulatory approval from the FERC in order to borrow on a short-term basis. The Company has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time. In November 2004, the Company received approval from the FERC to incur up to $400 million in short-term borrowings for an additional two-year period beginning January 1, 2005 through December 31, 2006.

Critical Accounting Policies and Estimates

The Financial Statements and Notes to Financial Statements contain information that is pertinent to Management's Discussion and Analysis. In preparing the Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Financial Statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material affect on the Company's Financial Statements particularly as they relate to pension expense. However, the Company believes it has taken reasonable but conservative positions, where assumptions and estimates are used, in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised is in the valuation of pension plan assumptions, contingency reserves, accrued removal obligations, regulatory assets and liabilities, unbilled revenue, the allowance for uncollectible accounts receivable and fair value hedging policies. The selection, application and disclosure of the following critical accounting estimates have been discussed with the Company's audit committee.

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, assumed discount rates and the level of funding. 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. The pension plan rate assumptions are shown in Note 11 of Notes to Financial Statements. The assumed return on plan assets is based on management's expectation

of the long-term return on the plan assets portfolio. The discount rate used to compute the present value of plan liabilities is based generally on rates of high-grade corporate bonds with maturities similar to the average period over which benefits will be paid. The level of funding is dependent on returns on plan assets and future discount rates. Higher returns on plan assets and increases in discount rates will reduce funding requirements to the plan. The following table indicates the sensitivity of the pension plans funded status to these variables.

	Change	Impact on Funded Status
Actual plan asset returns	+/- 5 percent	+/- $18.1 million
Discount rate	+/- 0.25 percent	+/- $18.6 million
Contributions	+ $10.0 million	+ $10.0 million
Expected long-term return on plan assets	+/- 1 percent	None

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 financial statements.

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations," which applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. The scope of SFAS No. 143 includes the Company's accrued plant removal costs for generation, transmission and distribution assets. SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of the fair value can be made. If a reasonable estimate of the fair value cannot be made in the period the asset retirement obligation is incurred, the liability shall be recognized when a reasonable estimate of the fair value can be made. In connection with the adoption of SFAS No. 143, the Company assessed whether it had a legal obligation within the scope of SFAS No. 143. The Company determined that it had a legal obligation to retire certain assets. As the Company currently has no plans to retire any of these assets (except as discussed below) and the remaining life is indeterminable, an asset retirement obligation was not recognized; however, the Company will monitor these assets and record a liability when a reasonable estimate of the fair value can be made. During the third quarter of 2004, the Company determined the definite life of a legal obligation within the scope of SFAS No. 143 to retire certain assets related to the expiration of a power supply contract in June 2006. The Company recorded an asset retirement obligation of approximately $1.1 million at September 30, 2004 and began amortizing this amount for 21 months beginning October 1, 2004.

The Company expects that the FASB will issue an interpretation related to SFAS No. 143 during the first quarter of 2005 in which an entity would be required to recognize a liability for the fair value of an asset retirement obligation that is conditional on a future event if the liability's fair value can be reasonably estimated. The fair value of a liability for the conditional asset retirement obligation would be recognized when incurred. Uncertainty surrounding the

timing and method of settlement that may be conditional on events occurring in the future would be factored into the measurement of the liability rather than the recognition of the liability. However, in some cases, there is insufficient information to estimate the fair value of an asset retirement obligation. In these cases, the liability would be initially recognized in the period in which sufficient information is available for an entity to make a reasonable estimate of the liability's fair value. The Company expects that this interpretation will be effective no later than the end of fiscal years ending after December 15, 2005. Additionally, the interpretation is expected to permit, but not require, restatement of interim financial information during any period of adoption. The FASB also has indicated that it will require both recognition of a cumulative change in accounting principle and disclosure of the liability on a pro forma basis for transition purposes. The Company will evaluate the financial impact when a final interpretation is issued.

The Company engages in fair value hedge transactions to modify the rate composition of the debt portfolio. The Company has entered into an interest rate swap agreement on the debt portfolio to modify the interest rate exposure on fixed rate debt issues. This interest rate swap qualifies as a fair value hedge under SFAS No. 133. The objective of this interest rate swap 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.

The Company, as a regulated utility, is subject to the accounting principles prescribed by SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 provides that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment. Excluding recoverable take or pay gas charges, the McClain Plant operating and maintenance expenses, depreciation, ad valorem taxes and interest on debt, regulatory assets are being amortized and reflected in rates charged to customers over periods of up to 20 years.

The Company records certain actual or anticipated costs and obligations as regulatory assets or liabilities if it is probable, based on regulatory orders or other available evidence, that the cost or obligation will be included in amounts allowable for recovery or refund in future rates.

The Company 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 Balance Sheets and in Operating Revenues on the Statements of Income based on estimates of usage and prices during the period. At December 31, 2004, if the estimated usage or price used in the unbilled revenue calculation were to increase or decrease by one percent, this would cause a change in the unbilled revenues recognized of approximately $0.5 million. At December 31, 2004 and 2003, Accrued Unbilled Revenues were approximately

$45.5 million and $38.0 million, respectively. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

Customer balances are generally written off if not collected within six months after the original due date. 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. At December 31, 2004, if the provision rate were to increase or decrease by 10 percent, this would cause a change in the uncollectible expense recognized of approximately $0.3 million. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Balance Sheets and is included in Other Operation and Maintenance Expense on the Statements of Income. The allowance for uncollectible accounts receivable was approximately $2.7 million and $2.6 million at December 31, 2004 and 2003, respectively.

Accounting Pronouncements

See Note 2 of Notes to Financial Statements for a discussion of recent accounting pronouncements that are applicable to the Company.

Electric Competition; Regulation

The Company has been and will continue to be affected by competitive changes to the utility and energy industries. Significant changes already have occurred and additional changes are being proposed to the wholesale electric market. Although it appears unlikely in the near future that changes will occur to retail regulation in the states served by the Company 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 the Company conducts its business. These developments at the federal and state levels are described in more detail in Note 13 of Notes to Financial Statements. The Company currently has one important matter pending before the OCC. See Note 13 of Notes of Financial Statements for a further discussion.

Commitments and Contingencies

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

results of operations or cash flows. This assessment of currently pending or threatened lawsuits is subject to change. See Note 12 of Notes to Financial Statements for a discussion of the Company's commitments and contingencies.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Risk Management

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

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.

Fair Value Hedge

At December 31, 2004 and 2003, the Company had one outstanding interest rate swap agreement that qualified as a fair value hedge 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. The objective of this interest rate swap 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. This interest rate swap qualified as a fair value hedge under Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, and met all of the requirements for a determination that there was no ineffective portion as allowed by the shortcut method under SFAS No. 133.

At December 31, 2004 and 2003, the fair values pursuant to the interest rate swap were approximately $3.9 million and $4.0 million, respectively, and the hedge was classified as Deferred Charges and Other Assets – Price Risk Management in the Balance Sheets. A corresponding net increase of approximately $3.9 million and $4.0 million was reflected in Long-Term Debt at December 31, 2004 and 2003, respectively, as this fair value hedge was effective at December 31, 2004 and 2003.

The fair value of the Company's long-term debt is based on quoted market prices. The valuation of the Company's interest rate swap was determined primarily based on quoted market prices. The following table shows the Company's long-term debt maturities and the weighted-average interest rates by maturity date.

(Dollars in millions)	2005	Thereafter	Total	12/31/04 Fair Value
Fixed rate debt				

Principal amount	$ 109.9	$ 488.6	$ 598.5	$ 650.3
Weighted-average interest rate	7.13%	6.54%	6.65%	---
Variable rate debt				
Principal amount (A)	---	$ 248.7	$ 248.7	$ 249.3
Weighted-average interest rate	---	1.75%	1.75%	---

(A) Amount includes an increase to the fair value of long-term debt of approximately $3.9 million due to the Company's interest rate swap.

Item 8. Financial Statements and Supplementary Data.

OKLAHOMA GAS AND ELECTRIC COMPANY
BALANCE SHEETS

December 31 *(In millions)*	**2004**	2003
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ ---**	$ 4.0
Accounts receivable - customers, net	**91.7**	123.1
Accounts receivable - other, net	**13.7**	9.9
Advances to parent	**26.5**	51.8
Accrued unbilled revenues	**45.5**	38.0
Fuel inventories, at LIFO cost	**42.2**	46.3
Materials and supplies, at average cost	**50.3**	41.4
Accumulated deferred tax assets	**9.0**	6.8
Fuel clause under recoveries	**54.3**	4.0
Recoverable take or pay gas charges	**17.0**	---
Other	**6.0**	6.2
Total current assets	**356.2**	331.5
OTHER PROPERTY AND INVESTMENTS, at cost	**4.8**	5.6
PROPERTY, PLANT AND EQUIPMENT		
In service	**4,539.0**	4,224.5
Construction work in progress	**94.4**	44.6
Other	**1.0**	1.0
Total property, plant and equipment	**4,634.4**	4,270.1
Less accumulated depreciation	**2,085.8**	2,006.0
Net property, plant and equipment	**2,548.6**	2,264.1
DEFERRED CHARGES AND OTHER ASSETS		
Recoverable take or pay gas charges	**---**	32.5
Income taxes recoverable from customers, net	**30.9**	31.6
Intangible asset - unamortized prior service cost	**31.8**	35.7
Prepaid benefit obligation	**67.2**	37.5
Price risk management	**3.9**	4.0
Other	**40.8**	32.7
Total deferred charges and other assets	**174.6**	174.0
TOTAL ASSETS	**$3,084.2**	$2,775.2

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

BALANCE SHEETS (Continued)

December 31 *(In millions)*	**2004**	2003
LIABILITIES AND STOCKHOLDER'S EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ ---**	$ 50.0
Accounts payable - affiliates	**45.4**	40.9
Accounts payable - other	**93.0**	57.7
Customers' deposits	**45.6**	35.8
Accrued taxes	**20.4**	20.6
Accrued interest	**16.4**	12.8
Tax collections payable	**7.1**	7.9
Accrued vacation	**11.6**	11.6
Price risk management	**0.1**	---
Gas imbalances	**0.1**	---
Fuel clause over recoveries	**---**	32.4
Provision for payments of take or pay gas	**21.0**	---
Other	**21.4**	15.3
Total current liabilities	**282.1**	285.0
LONG-TERM DEBT	**847.2**	707.2
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued pension and benefit obligations	**155.5**	134.8
Accumulated deferred income taxes	**570.4**	535.9
Accumulated deferred investment tax credits	**36.8**	42.0
Accrued removal obligations, net	**122.2**	116.3
Provision for payments of take or pay gas	**---**	32.5
Asset retirement obligation	**1.1**	---
Other	**6.5**	1.6
Total deferred credits and other liabilities	**892.5**	863.1
STOCKHOLDER'S EQUITY		
Common stockholder's equity	**665.5**	512.4
Retained earnings	**461.0**	460.9
Accumulated other comprehensive loss, net of tax	**(64.1)**	(53.4)
Total stockholder's equity	**1,062.4**	919.9
TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY	**$3,084.2**	$2,775.2

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

OKLAHOMA GAS AND ELECTRIC COMPANY
STATEMENTS OF CAPITALIZATION

December 31 *(In millions)*	**2004**	2003
STOCKHOLDER'S EQUITY		
Common stock, par value $2.50 per share; authorized 100.0 shares; and outstanding 40.4 shares	**$ 100.9**	$ 100.9
Premium on capital stock	**564.6**	411.5
Retained earnings	**461.0**	460.9
Accumulated other comprehensive loss, net of tax	**(64.1)**	(53.4)
Total stockholder's equity	**1,062.4**	919.9

LONG-TERM DEBT

SERIES	DATE DUE
Senior Notes-	

7.125 %	Senior Notes, Series Due October 15, 2005	**110.0**	110.0
6.50 %	Senior Notes, Series Due July 15, 2017	**125.0**	125.0
Variable %	Senior Notes, Series Due October 15, 2025	**114.0**	114.0
6.65 %	Senior Notes, Series Due July 15, 2027	**125.0**	125.0
6.50 %	Senior Notes, Series Due April 15, 2028	**100.0**	100.0
6.50 %	Senior Notes, Series Due August 1, 2034	**140.0**	---
Other bonds-			
Variable %	Garfield Industrial Authority, January 1, 2025	**47.0**	47.0
Variable %	Muskogee Industrial Authority, January 1, 2025	**32.4**	32.4
Variable %	Muskogee Industrial Authority, June 1, 2027	**56.0**	56.0
Unamortized premium and discount, net		**(2.2)**	(2.2)
Total long-term debt		**847.2**	707.2
Total Capitalization		**$1,909.6**	$1,627.1

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

OKLAHOMA GAS AND ELECTRIC COMPANY
STATEMENTS OF INCOME

Year ended December 31 *(In millions)*	**2004**	2003	2002
OPERATING REVENUES	$**1,578.1**	$1,517.1	$1,388.0
COST OF GOODS SOLD*	**914.5**	837.4	695.8
Gross margin on revenues	**663.6**	679.7	692.2
Other operation and maintenance	**301.9**	294.8	282.9
Depreciation	**122.7**	121.8	123.1
Taxes other than income	**47.0**	46.9	47.1
OPERATING INCOME	**192.0**	216.2	239.1
OTHER INCOME (EXPENSE)			
Other income	**6.1**	0.8	0.7
Other expense	**(2.7)**	(3.2)	(3.1)
Net other income (expense)	**3.4**	(2.4)	(2.4)
INTEREST INCOME (EXPENSE)			
Interest income	**2.7**	0.6	1.2
Interest on long-term debt	**(36.9)**	(36.9)	(38.1)
Allowance for borrowed funds used during construction	**1.7**	0.5	0.9
Interest on short-term debt and other interest charges	**(2.3)**	(2.4)	(3.0)
Net interest expense	**(34.8)**	(38.2)	(39.0)
INCOME BEFORE TAXES	**160.6**	175.6	197.7
INCOME TAX EXPENSE	**53.0**	60.2	71.6
NET INCOME	**$ 107.6**	$ 115.4	$ 126.1

* Before intercompany eliminations.

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

OKLAHOMA GAS AND ELECTRIC COMPANY

STATEMENTS OF RETAINED EARNINGS

Year ended December 31 *(In millions)*	**2004**	2003	2002
BALANCE AT BEGINNING OF PERIOD	**$ 460.9**	$ 455.2	$ 433.1
ADD: Net income	**107.6**	115.4	126.1
Total	**568.5**	570.6	559.2
DEDUCT: Dividends declared on common stock	**107.5**	109.7	104.0
BALANCE AT END OF PERIOD	**$ 461.0**	$ 460.9	$ 455.2

OKLAHOMA GAS AND ELECTRIC COMPANY
STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31 *(In millions)*	**2004**	2003	2002
Net income	**$ 107.6**	$ 115.4	$ 126.1
Other comprehensive income (loss), net of tax:			
Minimum pension liability adjustment [($17.4), $16.5 and ($71.0) pre-tax, respectively]	**(10.7)**	10.1	(43.6)
Total comprehensive income	**$ 96.9**	$ 125.5	$ 82.5

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

OKLAHOMA GAS AND ELECTRIC COMPANY
STATEMENTS OF CASH FLOWS

Year ended December 31 *(In millions)*	**2004**	2003	2002
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	**$ 107.6**	$ 115.4	$ 126.1
Adjustments to reconcile net income to net cash provided from operating activities			
Depreciation	**122.7**	121.8	123.1
Deferred income taxes and investment tax credits, net	**35.6**	107.6	8.4
Allowance for equity funds used during construction	**(0.9)**	---	---
Gain on sale of assets	**(3.2)**	---	---
Price risk management liabilities	**0.1**	---	---
Other assets	**(32.0)**	(3.9)	(32.8)
Other liabilities	**(0.6)**	(3.2)	0.1
Change in certain current assets and liabilities			
Accounts receivable - customers, net	**31.4**	(25.3)	7.0
Accounts receivable - other, net	**(3.8)**	(1.8)	3.8
Accrued unbilled revenues	**(7.5)**	(9.8)	7.4
Fuel, materials and supplies inventories	**(4.8)**	4.7	(18.6)
Fuel clause under recoveries	**(50.3)**	10.7	(14.7)
Other current assets	**4.3**	(1.1)	(0.5)
Accounts payable	**35.3**	(5.4)	5.6
Accounts payable - affiliates	**4.5**	11.9	0.1
Customers' deposits	**9.8**	2.7	4.6
Accrued taxes	**(0.2)**	0.3	0.1
Accrued interest	**3.6**	(1.0)	(0.6)
Gas imbalances liability	**0.1**	---	---

Fuel clause over recoveries	**(32.4)**	32.4	(23.4)
Other current liabilities	**5.3**	6.2	5.6
Net Cash Provided from Operating Activities	**224.6**	362.2	201.3
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures (less allowance for equity funds used during construction)	**(391.2)**	(148.7)	(198.7)
Proceeds from sale of assets	**3.3**	---	---
Net Cash Used in Investing Activities	**(387.9)**	(148.7)	(198.7)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from long-term debt	**138.6**	---	---
Increase (decrease) in short-term debt, net	**128.3**	(102.8)	101.1
Dividends paid on common stock	**(107.6)**	(107.0)	(103.8)
Net Cash Provided from (Used in) Financing Activities	**159.3**	(209.8)	(2.7)
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	**(4.0)**	3.7	(0.1)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**4.0**	0.3	0.4
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ ---**	$ 4.0	$ 0.3

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

OKLAHOMA GAS AND ELECTRIC COMPANY
NOTES TO FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Organization

Oklahoma Gas and Electric Company (the "Company") generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas and is subject to regulation by the Oklahoma Corporation Commission ("OCC"), the Arkansas Public Service Commission ("APSC") and the Federal Energy Regulatory Commission ("FERC"). The Company is a wholly-owned subsidiary of OGE Energy Corp. ("Energy Corp.") which is an energy and energy services provider offering physical delivery and management of both electricity and natural gas primarily in the south central United States. The Company was incorporated in 1902 under the laws of the Oklahoma Territory and is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. The Company sold its retail gas business in 1928 and is no longer engaged in the gas distribution business.

Accounting Records

The accounting records of the Company are maintained in accordance with the Uniform System of Accounts prescribed by the FERC and adopted by the OCC and the APSC. Additionally, the Company, as a regulated utility, is subject to the accounting principles prescribed by the Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards ("SFAS") No. 71, "Accounting for the Effects of Certain Types of Regulation." SFAS No. 71 provides that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment. Excluding recoverable take or pay gas charges, the McClain Plant operating and maintenance expenses, depreciation, ad valorem taxes and interest on debt in the table below, regulatory assets are being amortized and reflected in rates charged to customers over periods of up to 20 years.

The Company records certain actual or anticipated costs and obligations as regulatory assets or liabilities if it is probable, based on regulatory orders or other available evidence, that the cost or obligation will be included in amounts allowable for recovery or refund in future rates.

The following table is a summary of the Company's regulatory assets and liabilities at December 31:

(In millions)	**2004**	2003
Regulatory Assets		
Fuel clause under recoveries	**$ 54.3**	$ 4.0

Recoverable take or pay gas charges	**17.0**	32.5
Income taxes recoverable from customers, net	**30.9**	31.6
Unamortized loss on reacquired debt	**21.0**	22.1
McClain Plant expenses	**11.0**	---
January 2002 ice storm	**1.8**	3.6
Arkansas transition costs	**0.7**	---
Miscellaneous	**0.6**	0.4
Total Regulatory Assets	**$ 137.3**	$ 94.2
Regulatory Liabilities		
Accrued removal obligations, net	**$ 122.2**	$ 116.3
Estimated refund on gas transportation and storage case	**6.9**	---
Estimated refund on FERC fuel	**1.0**	1.0
Fuel clause over recoveries	**---**	32.4
Total Regulatory Liabilities	**$ 130.1**	$ 149.7

Fuel clause under recoveries are generated from under recoveries from the Company's customers when the Company's cost of fuel exceeds the amount billed to its customers. Fuel clause over recoveries are generated from over recoveries from the Company's customers when the amount billed to its customers exceeds the Company's cost of fuel. 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 above the baseline charge for fuel and over recovers fuel cost when prices decline below the baseline charge for fuel. Provisions in the fuel clauses allow the Company to amortize under or over recovery. The Company expects to recover the fuel clause under recoveries during 2005.

Recoverable take or pay gas charges represent the Company's estimate of the maximum amount that it could be obligated to pay under certain take-or-pay contracts. The Company believes that it is entitled to recover any such amounts from its customers through its regulatorily approved automatic fuel adjustment clauses or other regulatory mechanisms.

Income taxes recoverable from customers represent income tax benefits previously used to reduce the Company'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 income tax related regulatory assets and liabilities are netted on the Company's Balance Sheets in the line item, "Income Taxes Recoverable from Customers, Net."

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

As a result of the acquisition of a 77 percent interest in the 520 megawatt ("MW") NRG McClain Station (the "McClain Plant") completed on July 9, 2004, and consistent with the 2002 agreed-upon settlement of the Company's rate case (the "Settlement Agreement") with the OCC, the Company has the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the acquisition and operation of the McClain Plant, consisting of the non-fuel operation and maintenance expenses, depreciation, cost of debt associated with the investment and ad valorem taxes. All prudently incurred costs accrued through the regulatory asset within the 12-month period would be included in the Company's prospective cost of service and would be recovered over a period to be determined by the OCC.

On November 22, 2002, the OCC signed a rate order containing the provisions of a Settlement Agreement of the Company's rate case. The Settlement Agreement provides for, among other things, recovery by the Company, over three years, of the $5.4 million in deferred operating costs, associated with the January 2002 ice storm, through the Company's rider for sales to other utilities and power marketers ("off-system sales"). Previously, the Company had a 50/50 sharing mechanism in Oklahoma for any off-system sales. The Settlement Agreement provided that the first $1.8 million in annual net profits from the Company's off-system sales will go to the Company, the next $3.6 million in annual net profits from off-system sales will go to the Company's Oklahoma customers, and any net profits of off-system sales in excess of these amounts will be credited in each sales year with 80 percent to the Company's Oklahoma customers and the remaining 20 percent to Company. If any of the $5.4 million is not recovered at the end of the three years, the OCC will authorize the recovery of any remaining costs. During the year ended December 31, 2004, the Company recovered approximately $1.8 million in annual net profits from off-system sales, gave approximately $3.6 million in annual net profits from off-system sales to the Company's Oklahoma customers and the net profits from off-system sales that exceeded the $5.4 million were shared with 80 percent to the Company's Oklahoma customers and the remaining 20 percent to the Company.

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

Accrued removal obligations represent asset retirement costs previously recovered from ratepayers for other than legal obligations. In accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations," the Company was required to reclassify its accrued removal

obligations, which had previously been recorded as a liability in Accumulated Depreciation, to a regulatory liability.

On November 22, 2002, the OCC signed a rate order containing the provisions of the Settlement Agreement of the Company's rate case. As part of the

Settlement Agreement, the Company agreed to consider competitive bidding as a basis to select its provider for gas transportation service to its natural gas-fired generation facilities pursuant to the terms set forth in the Settlement Agreement. The prescribed bidding process detailed in the Settlement Agreement provided that each generation facility seek bids separately for the services required. The Company believes that in order for it to achieve maximum coal generation, deliver the lowest cost energy to its customers and ensure reliable electric service, it must have integrated, firm no-notice load following service for both gas transportation and gas storage. On April 29, 2003, as required by the Settlement Agreement, the Company filed an application with the OCC in which the Company advised the OCC that, after careful consideration, competitive bidding for gas transportation was rejected in favor of a new intrastate integrated, firm no-notice load following gas transportation and storage services agreement with its affiliate Enogex Inc. and subsidiaries ("Enogex"). On October 22, 2004, the administrative law judge overseeing the proceeding recommended approximately $41.9 million annual demand fee recovery with the Company refunding to its customers any demand fees collected in excess of this amount. If this recommendation is ultimately accepted, the Company believes its refund obligation would be approximately $6.9 million at December 31, 2004, which the Company does not believe is material in light of previously established reserves. See Note 13 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; the financial effects of which could be significant.

Use of Estimates

In preparing the Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Financial Statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material affect on the Company's Financial Statements particularly as they relate to pension expense. However, the Company believes it has taken reasonable but conservative positions, where assumptions and estimates are used, in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised is in the valuation of pension plan assumptions, contingency reserves, accrued removal obligations, regulatory assets and liabilities, unbilled revenue, the allowance for uncollectible accounts receivable and fair value hedging policies.

Cash and Cash Equivalents

For purposes of the 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.

The Company's cash management program utilizes controlled disbursement banking arrangements. Outstanding checks in excess of cash balances were approximately $21.7 million and $19.0 million at December 31, 2004 and 2003, respectively, and are classified as Accounts Payable in the Balance Sheets. Sufficient funds were available to fund these outstanding checks when they were presented for payment.

Allowance for Uncollectible Accounts Receivable

Customer balances are generally written off if not collected within six months after the original due date. 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 was approximately $2.7 million and $2.6 million at December 31, 2004 and 2003, respectively.

New business customers are required to provide a security deposit in the form of a case, bond, or irrevocable letter of credit which is refunded when the account is closed. New residential customers, whose outside credit scores indicate risk, are required to provide a security deposit which is refunded after 12 months of good payment history per the regulatory rules. The payment behavior of all existing customers is monitored and if the payment behavior indicates sufficient risk per the regulatory rules, customers will be required to provide a security deposit.

Fuel Inventories

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 $13.7 million and $24.9 million for 2004 and 2003, respectively, based on the average cost of fuel purchased. The amount of fuel inventory was approximately $42.2 million and $60.0 million at December 31, 2004 and 2003, respectively.

Effective December 31, 2003, approximately $13.7 million of natural gas storage inventory that was previously classified as Fuel Inventories was reclassified to Property, Plant and Equipment on the Balance Sheet due to the gas transportation and storage contract between the Company and Enogex requiring a minimum volume of natural gas be kept in the Enogex system.

Property, Plant and Equipment

All property, plant and equipment are recorded at cost. Newly constructed plant is added to plant balances at costs which include contracted services, direct labor, materials, overhead, transportation costs and the allowance for funds used during construction ("AFUDC"). Replacements of major units of property are capitalized as plant. The replaced plant is removed from plant balances and the cost of such property less salvage is charged to Accumulated Depreciation. Repair and replacement of minor items of property are included in the Statements of Income as Other Operation and Maintenance Expense.

Effective January 1, 2003, removal expense has no longer been charged to Accumulated Depreciation but rather has been charged to regulatory liabilities in accordance with SFAS No. 143.

The Company's property, plant and equipment are divided into the following major classes at December 31, 2004 and 2003, respectively.

December 31 *(In millions)*	**2004**	2003
Distribution assets	**$ 1,934.0**	$ 1,834.7
Electric generation assets	**1,828.3**	1,628.1
Transmission assets	**552.8**	536.9
Intangible plant	**6.3**	5.3
Other property and equipment	**313.0**	265.1
Total property, plant and equipment	**$ 4,634.4**	$ 4,270.1

Depreciation

The provision for depreciation, which was approximately 2.9 percent of the average depreciable utility plant for 2004 and 2003, is provided on a straight-line method over the estimated service life of the utility assets. Depreciation is provided at the unit level for production plant and at the account or sub-account level for all other plant, and is based on the average life group method.

Allowance for Funds Used During Construction

AFUDC is calculated according to the FERC pronouncements for the imputed cost of equity and borrowed funds. AFUDC, a non-cash item, is reflected as a credit in the Statements of Income and as a charge to Construction Work in Progress in the Balance Sheets. AFUDC rates, compounded semi-annually, were 4.99 percent, 1.67 percent and 2.40 percent for the years 2004, 2003 and 2002, respectively. The increase in the AFUDC rates in 2004 was primarily due to a portion of capital expenditures being funded by equity funds, which have a higher cost rate than short-term borrowings, which were used to fund capital expenditures in 2003 and 2002.

Revenue Recognition

The Company 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.

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 the Company's customers through automatic fuel adjustment clauses, which are subject to periodic review by the OCC, the APSC and the FERC. See Note 13 of Notes to Financial Statements for a discussion of the proceeding before the OCC in which the Company is seeking to recover costs billed to it by Enogex for gas transportation and storage services.

Accrued Vacation

The Company accrues vacation pay by establishing a liability for vacation earned during the current year, but not payable until the following year.

Accumulated Other Comprehensive Loss

Accumulated Other Comprehensive Loss includes approximately a $64.1 million after tax loss ($104.6 million pre-tax) and approximately a $53.4 million after tax loss ($87.1 million pre-tax), respectively, at December 31, 2004 and 2003 related to a minimum pension liability adjustment based on a review of the funded status of Energy Corp.'s pension plan by the Company's actuarial consultants as of December 31, 2004.

Environmental Costs

Accruals for environmental costs are recognized when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. When a single estimate of the liability cannot be determined, the low end of the estimated range is recorded. Costs are charged to expense or deferred as a regulatory asset based on expected recovery from customers in future rates, if they relate to the remediation of conditions caused by past operations or if they are not expected to mitigate or prevent contamination from future operations. Where environmental expenditures relate to facilities currently in use, such as pollution control equipment, the costs may be capitalized and depreciated over the future service periods. Estimated remediation costs are recorded at undiscounted amounts, independent of any insurance or rate recovery, based on prior experience, assessments and current technology. Accrued obligations are regularly adjusted as environmental assessments and estimates are revised, and remediation efforts proceed. For sites where the Company has been designated as one of several potentially responsible parties, the amount accrued represents the Company's estimated share of the cost.

Related Party Transactions

Energy Corp. allocated operating costs to the Company of approximately $89.6 million, $84.4 million and $95.2 million during 2004, 2003 and 2002, respectively. Energy Corp. 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.

In 2004, 2003 and 2002, the Company paid Enogex approximately $34.3 million, $33.5 million and $33.6 million, respectively, for transporting gas to the Company’s natural gas-fired generating facilities. In 2004, 2003 and 2002, the Company paid Enogex approximately $15.3 million, $11.2 million and $3.3 million, respectively, for natural gas storage services. In 2004, 2003 and 2002, the Company also recorded natural gas purchases from Enogex of approximately $45.2 million, $20.8 million and $13.9 million, respectively. Approximately $8.4 million and approximately $3.9 million were recorded at December 31, 2004 and 2003, respectively, and are included in Accounts Payable – Affiliates in the Balance Sheet for these activities. There were no amounts recorded for these activities at December 31, 2003. See Note 13 for a discussion of the gas transportation and storage contract between the Company and Enogex.

In 2004, 2003 and 2002, the Company recorded interest income of approximately $0.7 million, $0.1 million and $0.3 million, respectively, from Energy Corp. for advances made by the Company to Energy Corp.

In 2004, 2003 and 2002, the Company recorded interest expense of approximately $0.4 million, $1.1 million and $0.7 million, respectively, to Energy Corp. for advances made by Energy Corp. to the Company. The interest rate charged on advances to the Company from Energy Corp. approximates Energy Corp.’s commercial paper rate.

In 2004, 2003 and 2002, the Company paid approximately $107.4 million, $107.0 million and $103.8 million, respectively, in dividends to Energy Corp.

Reclassifications

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

2. Accounting Pronouncements

In June 2001, the FASB issued SFAS No. 143, which applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. The scope of SFAS No. 143

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

The Company expects that the FASB will issue an interpretation related to SFAS No. 143 during the first quarter of 2005 in which an entity would be required to recognize a liability for the fair value of an asset retirement obligation that is conditional on a future event if the liability’s fair value can be reasonably estimated. The fair value of a liability for the conditional asset retirement obligation would be recognized when incurred. Uncertainty surrounding the timing and method of settlement that may be conditional on events occurring in the future would be factored into the measurement of the liability rather than the recognition of the liability. However, in some cases, there is insufficient information to estimate the fair value of an asset retirement obligation. In these cases, the liability would be initially recognized in the period in which sufficient information is available for an entity to make a reasonable estimate of the liability’s fair value. The Company expects that this interpretation will be effective no later than the end of fiscal years ending after December 15, 2005. Additionally, the interpretation is expected to permit, but not require, restatement of interim financial information during any period of adoption. The FASB also has indicated that it will require both recognition of a cumulative change in accounting principle and disclosure of the liability on a pro forma basis for transition purposes. The Company will evaluate the financial impact when a final interpretation is issued.

In November 2004, the FASB issued SFAS No. 151, “Inventory Costs, an Amendment to ARB No. 43, Chapter 4.” This statement amends the guidance in Accounting Research Bulletin No. 43, Chapter 4 “Inventory Pricing”, to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs and spoilage. This statement requires these items to be

recognized as current period charges regardless of whether the “so abnormal” criterion is met. Adoption of SFAS No. 151 is required for inventory costs incurred during fiscal years beginning after June 15, 2005. The Company will adopt this new standard effective January 1, 2006. Management has not yet determined what the impact of this new standard will be on its financial position or results of operations.

In December 2004, the FASB issued SFAS No. 123 (Revised), "Share-Based Payment", which replaces SFAS No. 123, "Accounting for Stock-Based Compensation," and supersedes Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees." This statement applies to all share-based payment transactions in which an entity acquires goods or services by issuing (or offering to issue) its shares, share options or other equity instruments (except for equity instruments held by an employee share ownership plan) or by incurring liabilities to an employee or other supplier (a) in amounts based, at least in part, on the price of the entity's shares or other equity instruments or (b) that require or may require settlement by issuing the entity's equity shares or other equity instruments. This statement applies to all awards granted after the required effective date and to awards modified, repurchased or cancelled after that date. The cumulative effect of initially applying this statement, if any, is recognized as of the required effective date. This statement requires a public entity to measure and recognize the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award (with limited exceptions). The grant-date fair value of employee share options and similar instruments will be estimated using option-pricing models adjusted for the unique characteristics of those instruments. If an equity award is modified after the grant date, incremental compensation cost will be recognized in an amount equal to the excess of the fair value of the modified award over the fair value of the original award immediately before the modification. As of the required effective date, all public entities that used the fair-value based method for either recognition or disclosure under SFAS No. 123 will apply this statement using a modified version of prospective application. Under that transition method, compensation cost is recognized on or after the required effective date for the portion of outstanding awards for which the requisite service has not yet been rendered, based on the grant-date fair value of those awards calculated under SFAS No. 123 for either recognition or pro forma disclosures. For periods prior to the required effective date, those entities may elect to apply a modified version of retrospective application under which financial statements for prior periods are adjusted on a basis consistent with the pro forma disclosures required for those periods by SFAS No. 123. Adoption of SFAS No. 123(R) is required for public entities as of the beginning of the first interim or annual period beginning after June 15, 2005. The Company will adopt this new standard effective July 1, 2005. Management has not yet determined what the impact of this new standard will be on its financial position or results of operations.

3. Price Risk Management Assets and Liabilities

The Company periodically utilizes derivative contracts to reduce exposure to adverse interest rate fluctuations. During 2004 and 2003, the Company's use of price risk management instruments involved the use of an interest rate swap agreement. This agreement involved the exchange of fixed price or rate payments in exchange for floating price or rate payments over the life of the instrument without an exchange of the underlying principal amount.

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

The Company's interest rate swap agreement has been designated as a fair value hedge 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. See Note 9 for a description of the Company's interest rate swap agreement.

4. Asset Disposals

During the second quarter of 2004, the Company sold land and buildings near its principal executive offices for approximately $0.9 million. The Company recognized a gain of approximately $0.3 million related to the sale of this asset, which is recorded in Other Income in the Statements of Income.

In September 2004, the Company sold its interests in its natural gas producing properties for approximately $3.1 million. These interests had a carrying value of approximately $0.1 million and the Company recognized a gain of approximately $3.0 million, which is recorded in Other Income in the Statements of Income. In December 2004, the Company recognized an additional gain of approximately $0.2 million related to the sale of these interests.

5. Supplemental Cash Flow Information

The following table discloses information about investing and financing activities that affect recognized assets and liabilities but which do not result in cash receipts or payments. Also

disclosed in the table is cash paid for interest, net of interest capitalized, and cash paid for income taxes, net of income tax refunds.

Year ended December 31 *(In millions)*	**2004**	2003	2002
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Power plant long-term service agreement	**$ 6.0**	$ ---	$ ---
Change in fair value of long-term debt due to interest rate swap	**(0.1)**	(3.5)	9.9
Change in property, plant and equipment due to transfer of inventory	**---**	(13.7)	---
SUPPLEMENTAL CASH FLOW INFORMATION			

Cash Paid During the Period for			
Interest (net of interest capitalized of $1.7, $0.5, $0.9)	**$ 33.6**	$ 35.9	$ 35.6
Income taxes (net of income tax refunds)	**22.9**	(39.8)	61.9

6. Income Taxes

The items comprising income tax expense are as follows:

Year ended December 31 *(In millions)*	**2004**	2003	2002
Provision (Benefit) for Current Income Taxes			
Federal	**$ 13.1**	$ (42.0)	$ 55.9
State	**2.0**	(4.7)	7.7
Total Provision (Benefit) for Current Income Taxes	**15.1**	(46.7)	63.6
Provision for Deferred Income Taxes, net			
Federal	**38.5**	99.4	11.0
State	**2.2**	13.4	2.6
Total Provision for Deferred Income Taxes, net	**40.7**	112.8	13.6
Deferred Investment Tax Credits, net	**(5.2)**	(5.2)	(5.2)
Income Taxes Relating to Other Income and Deductions	**2.4**	(0.7)	(0.4)
Total Income Tax Expense	**$ 53.0**	$ 60.2	$ 71.6

In connection with the filing in the third quarter of 2003 of Energy Corp.'s consolidated income tax returns for 2002, Energy Corp. elected to change its tax method of accounting related to the capitalization of costs for self-constructed assets to another method prescribed in the Treasury regulations. The accounting method change is for income tax purposes only. For financial accounting purposes, the only change is recognition of the impact of the cash flow generated by accelerating income tax deductions. This is reflected in the financial statements as a switch from current income taxes payable to deferred income taxes payable. This tax accounting method change resulted in a one-time catch-up deduction for costs previously capitalized under the prior method, resulting in a consolidated tax net operating loss for 2002. This tax net operating loss eliminated Energy Corp.'s current federal and state income tax liability for 2002 and all estimated payments made for 2002 have been refunded. Energy Corp. received federal and state income tax refunds of approximately $50.8 million during 2003 related to this tax accounting method change.

The following schedule reconciles the statutory federal tax rate to the effective income tax rate:

Year ended December 31	**2004**	2003	2002
Statutory federal tax rate	**35.0%**	35.0%	35.0%
State income taxes, net of federal income tax benefit	**2.9**	3.6	3.4
Tax credits, net	**(3.2)**	(2.9)	(2.6)
Other, net	**0.4**	(1.4)	0.4
Effective income tax rate as reported	**35.1%**	34.3%	36.2%

The Company is a member of an affiliated group that files consolidated income tax returns. Income taxes are allocated to each company in the affiliated group based on its separate taxable income or loss. Federal investment tax credits on electric utility property have been deferred and are being amortized to income over the life of the related property.

The Company 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.

The deferred tax provisions, set forth above, are recognized as costs in the ratemaking process by the commissions having jurisdiction over the rates charged by the Company. The components of Accumulated Deferred Taxes at December 31, 2004 and 2003 respectively, are as follows:

(In millions)	**2004**	2003
Current Accumulated Deferred Tax Assets		
Accrued vacation	**$ 3.8**	$ 3.9
Uncollectible accounts	**1.1**	1.1
Other	**4.1**	1.8

Total Current Accumulated Deferred Tax Assets	**$**	**9.0**	$	6.8
Non-Current Accumulated Deferred Tax Liabilities				
Accelerated depreciation and other property related differences	**$**	**536.4**	$	501.7
Allowance for funds used during construction		**31.1**		33.1
Income taxes refundable to customers		**12.0**		12.2
Bond redemption-unamortized costs		**7.3**		7.7
Other		**1.5**		(2.0)
Total Non-Current Accumulated Deferred Tax Liabilities		**588.3**		552.7
Non-Current Accumulated Deferred Tax Assets				
Deferred federal investment tax credits		**(10.4)**		(12.1)
Postretirement medical and life insurance benefits		**(5.9)**		(3.8)
Company pension plan		**(1.6)**		(0.9)
Total Non-Current Accumulated Deferred Tax Assets		**(17.9)**		(16.8)
Non-Current Accumulated Deferred Income Tax Liabilities, net	**$**	**570.4**	$	535.9

The Company has an Oklahoma investment tax credit ("ITC") carryover of approximately $3.3 million. These ITC carryover amounts will begin expiring in the year 2017. The Company believes that, based on current projections, these ITC carryover amounts will be fully utilized in 2005.

American Jobs Creation Act of 2004

On October 22, 2004, President Bush signed into law the American Jobs Creation Act of 2004 (the "Jobs Creation Act"). The Jobs Creation Act amended and added a significant number of provisions to the Internal Revenue Code and these changes affect virtually all taxpayers. The Jobs Creation Act includes a provision that entitles all U.S. manufacturers with qualified manufacturing activities to a "Deduction Related to Production Activities" ("DRPA"). Certain activities of the Company, including the generation of electricity, is included in the list of qualifying manufacturing activities for purposes of the DRPA. Thus, the Company believes that the DRPA could impact the Company's future effective income tax rate.

Beginning in 2005, the DRPA equals three percent of the lesser of: (a) taxable income derived from a qualified production activity; or (b) overall taxable income for the taxable year. However, the deduction for a taxable year is limited to 50 percent of the Form W-2 wages paid by a taxpayer during the taxable year in which the deduction is claimed. The deduction percentage increases to six percent in 2007. In 2010, when the deduction is fully phased-in, the deduction rate will be nine percent.

Because the Company is an integrated electric utility, it will be required to allocate income and expenses to its "qualified production activity." The U.S. Treasury Department issued guidance related to the DRPA on January 19, 2005 and this guidance provides rules for determining taxable income when a portion of a taxpayer's income is derived from a qualified production activity. The FASB has determined that the DRPA will be classified as a "special deduction" for purposes of computing income tax expense which will have the effect of reducing the Company's overall effective tax rate to the extent the Company can claim a deduction. The Company is in the process of analyzing these rules to determine the effect of the DRPA on its overall effective tax rate and income tax expense.

7. Common Stock and Cumulative Preferred Stock

There were no new shares of common stock issued during 2004, 2003 or 2002. The Company's Restated Certificate of Incorporation permits the issuance of a new series of preferred stock with dividends payable other than quarterly.

8. Stock Incentive Plan

On January 21, 1998, Energy Corp. adopted a Stock Incentive Plan (the "1998 Plan"). Under this Plan, restricted stock, stock options, stock appreciation rights and performance units may be granted to officers, directors and other key employees, including officers, directors and

employees of the Company. Energy Corp. had authorized the issuance of up to 4,000,000 shares under the 1998 Plan.

In 2003, Energy Corp. adopted, and its shareowners approved, a new Stock Incentive Plan (the "2003 Plan" and together with the 1998 Plan, the "Plans"). The 2003 Plan replaced the 1998 Plan and no further awards will be granted under the 1998 Plan. As under the 1998 Plan, under the 2003 Plan, restricted stock, stock options, stock appreciation rights and performance units may be granted to officers, directors and other key employees, including officers, directors and employees of the Company. Energy Corp. has authorized the issuance of up to 2,700,000 shares under the 2003 Plan.

Restricted Stock

During 2004 and 2003, no restricted stock was distributed under the Plans. The restricted stock previously distributed vests at the end of three years. Each share of restricted stock is subject to forfeiture if the recipient ceases to render substantial services to Energy Corp. or a subsidiary for any reason other than death, disability or retirement. Awards of restricted stock are subject to an additional condition with all or a portion of the shares of restricted stock being subject to forfeiture based on Energy Corp.'s return on equity compared to a peer group of companies during the three-year restriction period.

Performance Units

During 2004 and 2003, respectively, Energy Corp. awarded 162,591 performance units and 128,469 performance units to certain employees of Energy Corp. and its subsidiaries. These performance units represent the value of one share of Energy Corp.'s common stock. These performance units are contingently awarded and will be payable in cash or shares of Energy Corp.'s common stock subject to the condition that the number of performance units, if any, earned by the employees upon the expiration of a three-year award cycle is dependent on Energy Corp.'s total shareholder return relative to the total shareholder return of a peer group of companies. Each performance unit is subject to forfeiture if the recipient ceases to render substantial services to Energy Corp. or a subsidiary for any reason other than death, disability or retirement.

Stock Options

Options to purchase shares of Energy Corp. common stock may be granted under the Plans. Such options vest in one-third annual installments beginning one year from the date of grant and have a contractual life of 10 years. To date, no options have expired unexercised. Stock option transactions related to the Plans are summarized in the following table:

	2004		2003		2002	
	Number of Options	**Weighted Average Price**	Number of Options	Weighted Average Price	Number of Options	Weighted Average Price
Options Outstanding at beginning of year	**430,867**	**$22.2836**	349,800	$23.9551	258,300	$24.5569
Granted	**63,700**	**23.5750**	117,000	16.6850	92,100	22.2300
Exercised	**(62,031)**	**19.7562**	(27,033)	18.6791	(600)	18.2500
Cancelled	**(5,834)**	**19.9606**	(8,900)	25.3287	---	---
Options Outstanding at end of year	**426,702**	**$22.8755**	430,867	$22.2836	349,800	$23.9551
Options Exercisable at end of year	**278,658**	**$24.2359**	237,321	$25.0437	213,054	$25.2924

The fair value of each option grant under the Plans for the years ended December 31, 2004, 2003 and 2002, are estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions used for grants in 2004, 2003 and 2002:

	2004	2003	2002
Expected dividend yield	**6.27%**	6.30%	6.05%
Expected price volatility	**18.58%**	22.06%	22.95%
Risk-free interest rate	**3.77%**	3.80%	4.90%
Expected life of options (in years)	**7**	7	7
Weighted-average fair value of options granted	**$ 2.05**	$ 1.85	$ 3.10

The following table provides additional information about stock options outstanding at December 31, 2004:

		Options Outstanding		Options Exercisable	
Range of Exercise Prices	Weighted-Average Remaining Contractual Life	Number Outstanding	Weighted-Average Exercise Price	Number Outstanding	Weighted-Average Exercise Price
$16.69 - $22.50	7.10 years	218,402	$ 19.8105	127,558	$ 20.9131
$23.58 - $28.75	4.96 years	208,300	$ 26.0892	151,100	$ 27.0409

9. Long-Term Debt

A summary of the Company's long-term debt is included in the Statements of Capitalization. At December 31, 2004, the Company is in compliance with all of its debt agreements.

Long-Term Debt with Optional Redemption Provisions

The Company's 6.500 percent Senior Notes ("Senior Notes") series due July 15, 2017, were repayable on July 15, 2004, at the option of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to July 15, 2004. Only holders who submitted requests for repayment between May 15, 2004 and June 15, 2004 were entitled to such repayments. The Company and the Senior Note Trustee received no such requests for repayment of the Senior Notes.

The Company has three series of variable rate industrial authority bonds (the "Bonds") with optional redemption provisions that allow the holders to request repayment of the Bonds at various dates prior to the maturity. The Bonds, which are redeemable at the option of the holder during the next 12 months, are as follows:

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

All of these Bonds are subject to redemption at the option of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to the date of purchase. The bond holders, on any business day, can request repayment of the Bond by delivering an irrevocable notice to the tender agent stating the principal amount of the Bond, payment instructions for the purchase price and the business day the Bond is to be purchased. The repayment option may only be exercised by the holder of a Bond for the principal amount. A third party remarketing agent for the Bonds will attempt to remarket any Bonds tendered for purchase. Since the original issuance of these series of Bonds in 1995 and 1997, the remarketing agent has successfully remarketed all tendered bonds. If the remarketing agent is unable to remarket any such Bonds, the Company is obligated to repurchase such unremarketed Bonds. The Company has sufficient liquidity to meet these obligations.

Issuance of Long-Term Debt

In August 2004, the Company issued $140.0 million of long-term debt. The proceeds were used to replace a portion of the short-term borrowings initially used to fund a portion of the McClain Plant acquisition in July 2004. This debt has a maturity date of August 1, 2034 and an interest rate of 6.50 percent.

Interest Rate Swap Agreement

Fair Value Hedge

At December 31, 2004 and 2003, the Company had one outstanding interest rate swap agreement that qualified as a fair value hedge 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. The objective of this interest rate swap 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. This interest rate swap qualified as a fair value hedge under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, and met all of the requirements for a determination that there was no ineffective portion as allowed by the shortcut method under SFAS No. 133.

At December 31, 2004 and 2003, the fair values pursuant to the interest rate swap were approximately $3.9 million and $4.0 million, respectively, and the hedge was classified as

Deferred Charges and Other Assets – Price Risk Management in the Balance Sheets. A corresponding net increase of approximately $3.9 million and $4.0 million was reflected in Long-Term Debt at December 31, 2004 and 2003, respectively, as this fair value hedge was effective at December 31, 2004 and 2003.

Long-term Debt Maturities

Maturities of the Company's long-term debt during the next five years consist of $110.0 million in 2005; however, in the Statement of Capitalization at December 31, 2004, no amount is shown as Long-Term Debt Due Within One Year. The Company plans to refinance this amount and the Company believes they have the ability to do so as Energy Corp. and the Company entered into new five-year revolving credit agreements in October 2004 in an amount up to $550 million which could be utilized to temporarily finance these notes when they mature in October 2005.

The Company has previously incurred costs related to debt refinancings. Unamortized debt expense and unamortized loss on reacquired debt are classified as Deferred Charges and Other Assets – Other and unamortized premium and discount on long-term debt is classified as Long-Term Debt, respectively, in the Balance Sheets and are being amortized over the life of the respective debt.

10. Short-Term Debt

In December 2003, the Company issued commercial paper in anticipation of the planned acquisition of the McClain Plant by the end of 2003 and the short-term debt balance was approximately $50.0 million at December 31, 2003. Due to a delay in the completion of the McClain Plant acquisition, the Company transferred these funds to Energy Corp. for investment and at December 31, 2003, the Company had approximately $51.8 million in outstanding advances to Energy Corp. Due to the delay in the completion of the McClain Plant acquisition, Energy Corp. repaid the outstanding advances and the Company used these funds to repay the outstanding commercial paper balance during the first quarter of 2004. At December 31, 2004, the Company had approximately $26.5 million in outstanding advances to Energy Corp. and no commercial paper outstanding.

The following table shows Energy Corp.'s and the Company's lines of credit in place and available cash at December 31, 2004. At December 31, 2004, Energy Corp.'s short-term borrowings consisted of commercial paper.

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

Entity	Amount Available	Amount Outstanding	Maturity

Energy Corp.	$ 15.0	$ ---	April 6, 2005
The Company	100.0	---	October 20, 2009 (B)
Energy Corp. (A)	450.0	---	October 20, 2009 (B)
	565.0	---	
Cash	26.4	N/A	N/A
Total	$ 591.4	$ ---	

(A) This line of credit is used to back up a maximum of $300.0 million of Energy Corp.'s commercial paper borrowings, which were approximately $125.0 million at December 31, 2004.
(B) Each of the new credit facilities has a five-year term with two options to extend the term for one year.

On October 20, 2004, Energy Corp. and the Company entered into revolving credit agreements totaling $550 million. These agreements include two separate credit facilities, one for Energy Corp. in an amount up to $450 million and one for the Company in an amount up to $100 million. Each of the new credit facilities has a five-year term with two options to extend the term for one year.

Energy Corp.'s and the Company's ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade. Their respective back-up lines of credit contain rating grids that require annual fees and borrowing rates to increase if they suffer an adverse ratings impact. The impact of any future downgrades would result in an increase in the cost of short-term borrowings but would not result in any defaults or accelerations as a result of the rating changes.

Unlike Energy Corp. and Enogex, the Company must obtain regulatory approval from the FERC in order to borrow on a short-term basis. The Company has the necessary regulatory approvals to incur up to $400 million in short-term borrowings at any one time. In November 2004, the Company received approval from the FERC to incur up to $400 million in short-term borrowings for an additional two-year period beginning January 1, 2005 through December 31, 2006.

11. Retirement Plans and Postretirement Benefit Plans

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

Defined Benefit Pension Plan

All eligible employees of the Company are covered by a non-contributory defined benefit pension plan sponsored by Energy Corp. In early 2000, the Board of Directors of Energy Corp.

approved significant changes to the pension plan. Prior to these changes, benefits were based primarily on years of service and the average of the five highest consecutive years of compensation during an employee's last 10 years prior to retirement, with reductions in benefits for each year prior to age 62 that an employee retired and additional significant reductions for retirement prior to age 55. The changes made in 2000 included: (i) elimination of the significant reduction for employees electing to retire before age 55; (ii) the addition of an alternative method of computing the reduction in benefits (based on years of service and age); and (iii) the ability of an employee at time of retirement to receive, in lieu of an annuity, a lump sum payment equal to the present value of the annuity. Also, for employees hired after January 31, 2000, the pension plan will be a cash balance plan, under which Energy Corp. annually will credit to the employee's account an amount equal to five percent of the employee's annual compensation plus accrued interest. Employees hired prior to February 1, 2000, will receive the greater of the cash balance benefit or the benefit based on final average compensation as described above.

It is Energy Corp.'s policy to fund the plan on a current basis based on the net periodic SFAS No. 87 pension expense as determined by the Company's actuarial consultants. Additional amounts may be contributed from time to time to increase the funded status of the plan. During 2004 and 2003, Energy Corp. made contributions of approximately $69.0 million and $50.0 million, respectively, of which approximately $54.5 million and $38.8 million, respectively, were allocated to the Company, to ensure that the plan maintains an adequate funded status. Such contributions are intended to provide not only for benefits attributed to service to date, but also for those expected to be earned in the future. During 2005, Energy Corp. plans to contribute approximately $37.4 million to the plan, of which approximately $29.0 million is expected to be allocated to the Company. The expected contribution to the pension plan, anticipated to be in the form of cash, is a discretionary contribution and is not required to satisfy the minimum regulatory funding requirements specified by the Employee Retirement Income Security Act of 1974.

During 2004 and 2003, Energy Corp. made contributions to the pension plan and the restoration of retirement income plan that exceeded amounts previously recognized as net periodic pension expense and recorded a net prepaid benefit obligation at December 31, 2004 and 2003 of approximately $92.0 million and $55.7 million, respectively, of which approximately $67.0 million and $37.5 million, respectively, were allocated to the Company. At December 31, 2004 and 2003, Energy Corp.'s projected pension benefit obligation exceeded the fair value of pension plan assets and the restoration of retirement income plan assets by approximately $123.3 million and $131.8 million, respectively, of which approximately $105.9 million and $117.6 million, respectively, were allocated to the Company. As a result of recording a prepaid benefit obligation and having a funded status where the projected benefit obligations exceeded the fair value of plan assets, provisions of SFAS No. 87, "Employers' Accounting for Pensions," required the recognition of an additional minimum liability in the amount of approximately $156.6 million and $137.6 million, respectively, for Energy Corp., of which approximately $136.3 million and $122.8 million, respectively, were allocated to the Company at December 31, 2004 and 2003. The offset of this entry was an intangible asset and Accumulated Other Comprehensive Income, net of a deferred tax asset; therefore, this adjustment did not impact the results of operations in 2004 or 2003 and did not require a usage of cash and is therefore excluded from the Statements of Cash Flows. The amount recorded as an intangible asset equaled the unrecognized prior service cost with the remainder recorded in Accumulated Other Comprehensive Income. The amount in Accumulated Other Comprehensive Income represents a net periodic pension cost to be recognized in the Statements of Income in future periods.

The plan's assets consist primarily of investments in mutual funds, U.S. Government securities, listed common stocks and corporate debt. The following table shows, by major category, the percentage of the fair value of the plan assets held at December 31, 2004 and 2003:

	2004	2003
Equity securities	**62%**	61%
Debt securities	**36%**	38%
Other securities	**2%**	1%
Total	**100%**	100%

Investment Policies and Strategies

The plan assets are held in a master trust which follows an investment policy and strategy designed to maximize the long-term investment returns of the master trust at prudent risk levels. Common stocks are used as a hedge against moderate inflationary conditions, as well as for participation in normal economic times. Fixed income investments are utilized for high current income and as a hedge against deflation. Energy Corp. has retained an investment consultant responsible for the general investment oversight, analysis, monitoring investment guideline compliance and providing quarterly reports to certain of Energy Corp.'s members and Energy Corp.'s Employees' Benefit Funds Management Requirements Committee (the "Committee").

The various investment managers used by the master trust operate within the general operating objectives as established in the investment policy and within the specific guidelines established for their respective portfolio. The table below shows the target asset allocation percentages for each major category of plan assets:

Asset Class	Target Allocation	Minimum	Maximum
Domestic Equity	30%	---%	60%
Domestic Mid-Cap Equity	10%	---%	10%
Domestic Small-Cap Equity	10%	---%	10%
International Equity	10%	---%	10%
Fixed Income Domestic	38%	30%	70%
Cash	2%	---%	5%

The portfolio is rebalanced on a periodic basis to bring the asset allocations of various managers in line with the target asset allocation listed above. More frequent rebalancing may occur if there are dramatic price movements in the financial markets which may cause the trust's exposure to any asset class to exceed or fall below the established allowable guidelines.

To evaluate the progress of the portfolio, investment performance is reviewed quarterly. It is, however, expected that performance goals will be met over a full market cycle, normally defined as a three to five year period. Analysis of performance is within the context of the

prevailing investment environment and the advisors' investment style. The goal of the master trust is to provide a rate of return consistently from three to five percent over the rate of inflation (as measured by the national Consumer Price Index) over a typical market cycle of no less than three years and no more than five years. Each investment manager is expected to outperform its respective benchmark. Below is a list of each asset class utilized with appropriate comparative benchmark(s) each manager is evaluated against:

Asset Class	Comparative Benchmark(s)
Fixed Income	Lehman Aggregate Index
Value Equity	Russell 1000 Value Index - Short-term
	S&P 500 Index - Long-term
Growth Equity	Russell 1000 Growth Index - Short-term
	S&P 500 Index - Long-term
Mid-Cap Equity	Russell Midcap Index
Small-Cap Equity	Russell 2000 Index

Global Equity	Morgan Stanley Capital International Europe, Australia and Far East Index

The fixed income manager is expected to use discretion over the asset mix of the master trust assets in its efforts to maximize risk-adjusted performance. Exposure to any single issuer, other than the U.S. government, its agencies, or its instrumentalities (which have no limits) is limited to five percent of the fixed income portfolio as measured by market value. Exposure to any single non-government issue is limited to three percent. At least 80 percent of the invested assets must possess an investment grade rating at or above Baa3 or BBB- by Moody's Investors Service ("Moody's"), Standard & Poor's Ratings Services ("Standard & Poor's"), Fitch Ratings ("Fitch") or Duff & Phelps LLC. The manager may invest up to 10 percent of the portfolio's market value in cash equivalents (securities with less than six months to maturity). The portfolio may invest up to 10 percent of the portfolio's market value in convertible bonds as long as the securities purchased meet the quality guidelines. No mortgage derivatives or structured notes are permitted. The purchase of any of Energy Corp.'s or its subsidiaries equity, debt or other securities is prohibited unless prior approval of the Committee is received.

The domestic value equity managers focus on stocks that the manager believes are undervalued in price and earn an average or less than average return on assets, and often pays out higher than average dividend payments. The domestic growth equity manager will invest primarily in growth companies which consistently experience above average growth in earnings and sales, earn a high return on assets, and reinvest cash flow into existing business. The mid-cap equity portfolio manager focuses on companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell Midcap, small dividend yield, return on equity at or near the Russell Midcap and earnings per share growth rate at or near the Russell Midcap. The small-capitalization equity manager will purchase shares of companies with market capitalizations lower that the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell 2000, small dividend yield, return on equity at or near the Russell 2000 and earnings per share growth rate at or near the Russell 2000. The global equity manager invests primarily in non-dollar denominated equity securities.

Investing internationally diversifies the overall master trust across the global equity markets. The manager is required to operate under certain restrictions including: regional constraints, diversification requirements and percentage of U.S. securities. The Morgan Stanley Capital International Europe, Australia and the Far East Index ("EAFE") are the benchmark for comparative performance purposes. The EAFE Index is a market value weighted index comprised of over 1,000 companies traded on the stock markets of Europe, Australia, New Zealand and the Far East. All of the equities which are purchased for the fund are thoroughly researched.

For all equity investment managers, only companies with a market capitalization in excess of $100 million are allowable. No more than five percent of the portfolio can be invested in any one stock at the time of purchase. All securities are freely traded on a recognized stock exchange and there are no 144-A securities and no over-the-counter derivatives. The following investment categories are excluded: options (other than traded currency options), commodities, futures (other than currency futures or currency hedging), short sales/margin purchases, private placements, unlisted securities and real estate (but not real estate shares). A minimum of 95 percent of the total assets of an equity manager's portfolio must be allocated to the equity markets. Private placement or venture capital may not be purchased. All interest and dividend payments must be swept on a daily basis into a short-term money market or fund for re-deployment. The purchase of any of Energy Corp.'s or its subsidiaries equity, debt or other securities is prohibited unless prior approval of the Committee is received. The purchase of equity or debt issues of the portfolio manager's organization is also prohibited unless prior approval of the Committee is received.

Restoration of Retirement Income Plan

Energy Corp. provides a restoration of retirement income plan to those participants in Energy Corp.'s pension plan whose benefits are subject to certain limitations under the Internal Revenue Code (the "Code"). The benefits payable under this restoration of retirement income plan are equivalent to the amounts that would have been payable under the pension plan but for these limitations. The restoration of retirement income plan is intended to be an unfunded plan.

Postretirement Benefit Plans

In addition to providing pension benefits, Energy Corp. provides certain medical and life insurance benefits for retired members ("postretirement benefits"). Regular, full-time, active employees hired prior to February 1, 2000, whose age and years of service total or exceed 80 or have attained age 55 with 10 years of service at the time of retirement are entitled to these postretirement benefits. Employees hired after January 31, 2000, are not entitled to the postretirement medical benefits but are entitled to the postretirement life insurance benefits. Eligible retirees must contribute such amount as Energy Corp. specifies from time to time toward the cost of coverage for postretirement benefits. The benefits are subject to deductibles, co-payment provisions and other limitations. The Company charges to expense the SFAS No. 106, "Employers' Accounting for Postretirement Benefits other than Pensions," costs and includes an annual amount as a component of the cost-of-service in future ratemaking proceedings.

The details of the funded status of the pension plan (including the restoration of retirement income plan) and the postretirement benefit plans and the amounts included in the Balance Sheets are as follows:

Projected Benefit Obligations

	Pension Plan and Restoration of Retirement Income Plan		Postretirement Benefit Plans	
(In millions)	**2004**	2003	**2004**	2003
Beginning obligations	**$ (404.0)**	$ (373.9)	**$ (156.1)**	$ (160.9)
Service cost	**(11.3)**	(10.3)	**(2.1)**	(2.1)
Interest cost	**(24.4)**	(24.6)	**(9.6)**	(9.4)
Participants' contributions	**---**	---	**(2.5)**	(1.8)

Plan changes/other	**(1.3)**	(3.0)	---	---
Actuarial gains (losses)	**(43.5)**	(34.3)	**(6.1)**	7.8
Benefits paid	**37.4**	42.1	**11.6**	10.3
Ending obligations	**$ (447.1)**	$ (404.0)	**$ (164.8)**	$ (156.1)

Fair Value of Plans' Assets

	Pension Plan and Restoration of Retirement Income Plan		Postretirement Benefit Plans	
(In millions)	**2004**	2003	**2004**	2003
Beginning fair value	**$ 286.4**	$ 236.1	**$ 54.2**	$ 44.6
Actual return on plans' assets	**37.6**	53.6	**9.0**	9.5
Employer contributions	**54.6**	38.8	**7.8**	8.6
Participants' contributions	---	---	**2.6**	1.8
Benefits paid	**(37.4)**	(42.1)	**(11.6)**	(10.3)
Ending fair value	**$ 341.2**	$ 286.4	**$ 62.0**	$ 54.2

Net Periodic Benefit Cost

	Pension Plan and Restoration of Retirement Income Plan			Postretirement Benefit Plans		
(In millions)	**2004**	2003	2002	**2004**	2003	2002
Service cost	**$ 11.3**	$ 10.3	$ 9.1	**$ 2.1**	$ 2.1	$ 1.9
Interest cost	**24.4**	24.6	24.5	**9.6**	9.4	8.5
Return on plan assets	**(25.5)**	(19.9)	(22.6)	**(5.3)**	(5.2)	(5.3)
Amortization of transition obligation	---	---	---	**2.5**	2.5	2.5
Amortization of net loss	**9.6**	10.9	3.7	**4.6**	3.1	0.5
Amortization of unrecognized prior service cost	**5.2**	5.0	4.8	**1.5**	1.5	1.5
Net periodic benefit cost	**$ 25.0**	$ 30.9	$ 19.5	**$ 15.0**	$ 13.4	$ 9.6

The capitalized portion of the net periodic pension benefit cost was approximately $7.8 million, $5.7 million and $3.9 million at December 31, 2004, 2003 and 2002, respectively. The

capitalized portion of the net periodic postretirement benefit cost was approximately $4.7 million, $2.5 million and $1.9 million at December 31, 2004, 2003 and 2002, respectively.

Funded Status of Plans

	Pension Plan and Restoration of Retirement Income Plan		Postretirement Benefit Plans	
(In millions)	**2004**	2003	**2004**	2003
Funded status of the plans	**$ (105.9)**	$ (117.6)	**$ (102.8)**	$ (101.9)
Unrecognized net loss	**141.1**	119.3	**56.3**	58.5
Unrecognized prior service cost	**31.8**	35.8	**6.9**	8.4
Unrecognized transition obligation	---	---	**20.3**	22.9
Net amount recognized	**$ 67.0**	$ 37.5	**$ (19.3)**	$ (12.1)

Amounts recognized in the Balance Sheets consist of:

(In millions)	Pension Plan and Restoration of Retirement Income Plan 2004	2003
Prepaid benefit obligation	**$ 67.2**	$ 37.5
Accrued pension and benefit obligations	**(136.5)**	(122.8)
Intangible asset - unamortized prior service cost	**31.8**	35.7
Accumulated deferred tax asset	**40.4**	33.7
Accumulated other comprehensive loss, net of tax	**64.1**	53.4
Net amount recognized	**$ 67.0**	$ 37.5

Rate Assumptions

	Pension Plan			Postretirement Benefit Plans		
	2004	2003	2002	**2004**	2003	2002
Discount rate	**5.75%**	6.25%	6.75%	**5.75%**	6.25%	6.75%
Rate of return on plans' assets	**8.75%**	8.75%	9.00%	**8.75%**	8.75%	9.00%
Compensation increases	**4.50%**	4.50%	4.50%	**4.50%**	4.50%	4.50%
Assumed health care cost trend:						
Initial trend	**N/A**	N/A	N/A	**10.00%**	11.00%	12.00%
Ultimate trend rate	**N/A**	N/A	N/A	**4.50%**	4.50%	4.50%
Ultimate trend year	**N/A**	N/A	N/A	**2010**	2010	2010

N/A - not applicable

The overall expected rate of return on plan assets assumption remained 8.75 percent in 2003 and 2004 in determining net periodic pension cost. The rate of return on plan assets assumption is the average long-term rate of earnings expected on the funds currently invested and to be invested for the purpose of providing benefits specified by the pension plan or postretirement benefit plans. This assumption is reexamined at least annually and updated as necessary. The rate of return on plan assets assumption reflects a combination of historical return analysis, forward-looking return expectations and the plans' current and expected asset allocation.

The Company expects to pay benefits related to its pension plan and restoration of retirement income plan of approximately $49.3 million in 2005, $48.6 million in 2006, $46.4 million in 2007, $48.2 million in 2008, $49.1 million in 2009 and $227.8 million in years 2010 to 2014. These expected benefits were based on the same assumptions used to measure the Company's benefit obligation at the end of the year and include benefits attributable to estimated future employee service.

The assumed health care cost trend rates have a significant effect on the amounts reported for postretirement medical benefit plans. A one-percentage point change in the assumed health care cost trend rate would have the following effects:

ONE-PERCENTAGE POINT INCREASE

(In millions)	**2004**	2003	2002
Effect on aggregate of the service and interest cost components	**$ 1.5**	$ 1.5	$ 1.3
Effect on accumulated postretirement benefit obligations	**19.9**	19.2	19.6

ONE-PERCENTAGE POINT DECREASE

(In millions)	**2004**	2003	2002
Effect on aggregate of the service and interest cost components	**$ 1.2**	$ 1.2	$ 1.0
Effect on accumulated postretirement benefit obligations	**16.4**	15.7	16.1

Medicare Prescription Drug, Improvement and Modernization Act of 2003

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Medicare Act"). The Medicare Act expanded Medicare to include, for the first time, coverage for prescription drugs. Due to various uncertainties related to Energy Corp.'s response to this legislation in relation to its postretirement medical plan and the appropriate accounting methodology for this event, Energy Corp. elected to defer financial recognition of this legislation until the FASB issued final accounting guidance. This deferral election was permitted under FASB Staff Position No. FAS 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of

2003." In May 2004, the FASB issued FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." FAS 106-2 provides guidance on the accounting for the effects of the Medicare Act for employers that sponsor postretirement heath care plans that provide prescription drug benefits. FAS 106-2 also requires those employers to provide certain disclosures regarding the effect of the federal subsidy provided by the Medicare Act. For employers who elected to defer financial recognition, FAS 106-2 provides two alternative methods of adoption which include a retroactive application to the date of the Medicare Act's enactment or a prospective application as of the date of adoption. For employers who elected not to defer financial recognition, FAS 106-2 requires these employers to recognize a cumulative effect of a change in accounting principle in accordance with APB Opinion No. 20, "Accounting Changes." Adoption of FAS 106-2 is required for financial statements issued for periods

beginning after June 15, 2004. Energy Corp. adopted this new standard effective July 1, 2004 with retroactive application to the date of the Medicare Act's enactment. Management expects that the accumulated plan benefit obligation ("APBO") for Energy Corp.'s postretirement medical plan will be reduced by approximately $13.3 million as a result of savings to Energy Corp.'s postretirement medical plan resulting from the Medicare Act, which will reduce Energy Corp.'s costs for its postretirement medical plan by approximately $2.5 million annually, of which approximately $2.1 million is expected to be allocated to the Company. The $2.1 million in annual savings is comprised of a reduction of approximately $1.2 million from amortization of the $13.3 million gain due to the reduction of the APBO, a reduction in the interest cost on the APBO of approximately $0.7 million and a reduction in the service cost due to the subsidy of approximately $0.2 million.

The Company expects to pay gross benefits payments related to its postretirement benefit plans, including prescription drug benefits, of approximately $10.4 million in 2005, $10.1 million in 2006, $10.0 million in 2007, $10.6 million in 2008, $11.1 million in 2009 and $61.9 million in years 2010 to 2014. The Company expects to receive subsidy receipts related to its postretirement benefit plans of approximately $0.5 million in 2006, $0.5 million in 2007, $0.6 million in 2008, $0.6 million in 2009 and $3.6 million in years 2010 to 2014. The Company does not expect to receive any subsidy receipts in 2005.

Defined Contribution Plan

Energy Corp. provides a defined contribution savings plan. Each regular full-time employee of Energy Corp. or an affiliate is eligible to participate in the plan immediately. All other employees of Energy Corp. or an affiliate are eligible to become participants in the plan after completing one year of service as defined in the plan. Participants may contribute each pay period any whole percentage between two percent and 19 percent of their compensation, as defined in the plan, for that pay period. Contributions of the first six percent of compensation are called "Regular Contributions" and any contributions over six percent of compensation are called "Supplemental Contributions." Energy Corp. contributes to the Plan each pay period on behalf of each participant an amount equal to 50 percent of the participant's Regular Contributions for participants whose employment or re-employment date, as defined in the plan, occurred before February 1, 2000 and who have less than 20 years of service, as defined in the plan, and an amount equal to 75 percent of the participant's Regular Contributions for participants whose employment or re-employment date occurred before February 1, 2000 and who have 20 or more years of service. For participants whose employment or re-employment date occurred on or after February 1, 2000, Energy Corp. shall contribute 100 percent of the Regular Contributions deposited during such pay period by such participant. No Energy Corp. contributions are made with respect to a participant's Supplemental Contributions or with respect to a participant's Regular Contributions based on overtime payments, pay-in-lieu of overtime for exempt personnel and special lump-sum recognition awards and lump-sum merit awards included in compensation for determining the amount of participant contributions. Energy Corp.'s contribution which is allocated for investment to the Energy Corp. Common Stock Fund may be made in shares of Energy Corp.'s common stock or in cash which is used to invest in Energy Corp.'s common

stock. The Company contributed approximately $3.9 million, $3.6 million and $3.2 million during 2004, 2003 and 2002, respectively, to the defined contribution plan.

Deferred Compensation Plan

Energy Corp. provides a deferred compensation plan. The plan's primary purpose is to provide a tax-deferred capital accumulation vehicle for a select group of management, highly compensated employees and non-employee members of the Board of Directors of Energy Corp. and to supplement such employees' defined contribution plan contributions.

Eligible employees who enroll in the plan may elect to defer up to a maximum of 70 percent of base salary and 100 percent of bonus awards; however, the Benefits Committee, appointed by the Benefits Oversight Committee (which consists of at least two members appointed by the Board of Directors) may, at its discretion, permit participants to elect a deferral percentage of base salary and bonus awards based on the deferral percentage elected for a year under the defined contribution plan, with such deferrals to start when maximum deferrals to the defined contribution plan have been made because of limitations in that plan. Eligible directors who enroll in the plan may elect to defer up to a maximum of 100 percent of directors' meeting fees and annual retainers. Energy Corp. matches employee (but not non-employee director) deferrals to provide for the match that would have been made under the defined contribution plan had such deferrals been made under that plan without regard to the statutory limitations on elective deferrals and matching contributions applicable to the defined contribution plan. In addition, the Benefits Committee may award discretionary employer contribution credits to a participant under the plan. Energy Corp. accounts for the contributions in this plan as Accrued Pension and Benefit Obligations and Other Deferred Credits and the investment associated with these contributions is accounted for as Other Property and Investments in its Consolidated Balance Sheets. The appreciation of these investments is accounted for as Other Income and the increase in the liability under the plan is accounted for as Other Expense in Energy Corp.'s Consolidated Statements of Income.

Supplemental Executive Retirement Plan

Energy Corp. provides a supplemental executive retirement plan in order to attract and retain lateral hires or other executives designated by the Compensation Committee of Energy Corp.'s Board of Directors who may not otherwise qualify for a sufficient level of benefits under Energy Corp.'s pension plan. The supplemental executive retirement plan is intended to be an unfunded plan and not subject to the benefit limits imposed by the Code.

12. Commitments and Contingencies

Capital Expenditures

The Company's capital expenditures are estimated at approximately: 2005 – $235.7 million, 2006 – $215.0 million and 2007 – $197.0 million.

Operating Lease Obligations

The Company has an operating lease expiring March 31, 2006 for railcar leases. Future minimum payments for this noncancellable operating lease are as follows:

(In millions)	2005	2006	2007	2008	2009	2010 and Beyond
Railcars (A)	$ 5.4	$ 5.4	$ 5.3	$ 5.4	$ 5.3	$ 24.9

(A) The Company's current railcar operating lease expires March 31, 2006. The Company expects to enter into a similar lease agreement for railcars at the expiration of the current lease. Therefore, comparable future minimum payments have been included in the table above.

Payments for operating lease obligations were approximately $5.4 million, $5.4 million and $5.4 million in 2004, 2003 and 2002, respectively.

Railcar Leases

At December 31, 2004, the Company has a noncancellable operating lease which has purchase options covering 1,464 coal hopper railcars to transport coal from Wyoming to the Company's coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through the Company's tariffs and automatic fuel adjustment clauses. At the end of the lease term which is March 31, 2006, the Company has the option to purchase the railcars at a stipulated fair market value. If the Company chose not to purchase the railcars and the actual value of the railcars was less than the stipulated fair market value, the Company would be responsible for the difference in those values up to a maximum of approximately $36 million. The Company expects to enter into a new lease agreement for railcars effective April 1, 2006, which should negate any financial exposure under the current lease agreement. The Company is also required to maintain the railcars it has under lease to transport coal from Wyoming and has entered into agreements with Progress Rail Services and WATCO, both of which are non-affiliated companies, to furnish this maintenance.

Public Utility Regulatory Policy Act of 1978

The Company has entered into agreements with three qualifying cogeneration facilities having initial terms of three to 32 years. These contracts were entered into pursuant to the Public Utility Regulatory Policy Act of 1978 ("PURPA"). Stated generally, PURPA and the regulations thereunder promulgated by the FERC require the Company to purchase power generated in a manufacturing process from a qualified cogeneration facility ("QF"). The rate for such power to be paid by the Company was approved by the OCC. The rate generally consists of two components: one is a rate for actual electricity purchased from the QF by the Company; the other is a capacity charge, which the Company must pay the QF for having the capacity available. However, if no electrical power is made available to the Company for a period of time (generally three months), the Company's obligation to pay the capacity charge is suspended. The total cost of cogeneration payments is recoverable in rates from customers.

During 2004, 2003 and 2002, the Company made total payments to cogenerators of approximately $203.5 million, $203.0 million and $227.3 million, respectively, of which approximately $155.3 million, $164.7 million and $192.1 million, respectively, represented capacity payments. All payments for purchased power, including cogeneration, are included in the Statements of Income as Cost of Goods Sold. The future minimum capacity payments under the contracts are approximately: 2005 – $99.5 million, 2006 – $97.9 million, 2007 – $96.3 million, 2008 – $86.9 million and 2009 – $85.0 million.

Fuel Minimum Purchase Commitments

The Company purchased necessary fuel supplies of coal and natural gas for its generating units of approximately $166.5 million, $157.3 million and $164.1 million for the years ended December 31, 2004, 2003 and 2002, respectively. The Company has entered into purchase commitments of necessary fuel supplies of approximately: 2005 – $170.8 million, 2006 – $160.0 million, 2007 – $159.0 million, 2008 – $164.8 million, 2009 – $86.9 million and 2010 and Beyond – $165.5 million.

The Company has historically acquired some of its natural gas for boiler fuel under wellhead contracts that contain provisions allowing the owner to require prepayments for gas if certain minimum quantities are not taken. At December 31, 2004, approximately $21.0 million has been recorded in the Provision for Payments of Take or Pay Gas classified as Current Liabilities in the Balance Sheet. At December 31, 2003, approximately $32.5 million has been recorded in the Provision for Payments of Take or Pay Gas classified as Deferred Credits and Other Liabilities in the Balance Sheet. These amounts represent the Company's estimate of the maximum amount that it could be obligated to pay under certain take-or-pay contracts. The Company believes that it is entitled to recover any such amounts from its customers through its regulatorily approved automatic fuel adjustment clauses or other regulatory mechanisms.

Natural Gas Units

In April 2004, the Company utilized a request for bid ("RFB") to acquire approximately 56 percent and 26 percent of its projected annual natural gas requirements for 2005 and 2006, respectively. All of these contracts are tied to various gas price market indices and most will expire in December 2006. Additional natural gas supply for the summer of 2005 will be secured through a new RFB issued in the first quarter of 2005. The Company will meet additional natural gas requirements with monthly and daily purchases as required.

Natural Gas Measurement Cases

United States of America ex rel., Jack J. Grynberg v. Enogex Inc., Enogex Services Corporation and the Company. (United States District Court for the Western District of Oklahoma, Case No. CIV-97-1010-L.) United States of America ex rel., Jack J. Grynberg v. Transok Inc. et al. (United States District Court for the Eastern District of Louisiana, Case No. 97-2089; United States District Court for the Western District of Oklahoma, Case No. 97-1009M.). On June 15, 1999, the Company was served with Plaintiff's complaint, which is a qui

tam action under the False Claims Act. Plaintiff Jack J. Grynberg, as individual relator on behalf of the United States Government, alleges: (i) each of the named defendants have improperly or intentionally mismeasured gas (both volume and British thermal unit content) purchased from federal and Indian lands which have resulted in the under-reporting and underpayment of gas royalties owed to the Federal Government; (ii) certain provisions generally found in gas purchase contracts are improper; (iii) transactions by affiliated companies are not arms-length; (iv) excess processing cost deduction; and (v) failure to account for production separated out as a result of gas processing. Grynberg seeks the following damages: (a) additional royalties which he claims should have been paid to the Federal Government, some percentage of which Grynberg, as relator, may be entitled to recover; (b) treble damages; (c) civil penalties; (d) an order requiring defendants to measure the way Grynberg contends is the better way to do so; and (e) interest, costs and attorneys' fees.

In qui tam actions, the United States Government can intervene and take over such actions from the relator. The Department of Justice, on behalf of the United States Government, decided not to intervene in this action.

Plaintiff filed over 70 other cases naming over 300 other defendants in various Federal Courts across the country containing nearly identical allegations. The Multidistrict Litigation Panel entered its order in late 1999 transferring and consolidating for pretrial purposes approximately 76 other similar actions filed in nine other Federal Courts. The consolidated cases are now before the United States District Court for the District of Wyoming.

In October 2002, the Court granted the Department of Justice's motion to dismiss certain of Plaintiff's claims and issued an order dismissing Plaintiff's valuation claims against all defendants. Various procedural motions have been filed. Discovery is proceeding on limited jurisdictional issues as ordered by the Court. A hearing on the defendants' motions to dismiss for lack of subject matter jurisdiction, including public disclosure, original source and voluntary disclosure requirements is set for March 17 – 18, 2005.

The Company intends to vigorously defend this action. Since the case is in the early stages of motions and discovery, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company at this time.

Will Price (Price I) – On September 24, 1999, various subsidiaries of Energy Corp. were served with a class action petition filed in United States District Court, State of Kansas by Quinque Operating Company and other named plaintiffs, alleging mismeasurement of natural gas on non-federal lands. On April 10, 2003 the Court entered an order denying class certification. On May 12, 2003, Plaintiffs (now Will Price, Stixon Petroleum, Inc., Thomas F. Boles and the Cooper Clark Foundation, on behalf of themselves and other royalty interest owners) filed a motion seeking to file an amended petition and the court granted the motion on July 28, 2003. In this amended petition, the Company and Enogex Inc. were omitted from the case. Two subsidiaries of Enogex remain as defendants. The Plaintiffs' amended petition alleges that approximately 60 defendants, including two Enogex subsidiaries, have improperly measured

natural gas. The amended petition reduces the claims to: (1) mismeasurement of volume only; (2) conspiracy, unjust enrichment and accounting; (3) a putative Plaintiffs' class of only royalty owners; and (4) gas measured in three specific states. Discovery on class certification is proceeding. A hearing on class certification issues is set for April 1, 2005.

Energy Corp. intends to vigorously defend this action. Since the case is in the early stages of motions and discovery, Energy Corp. is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to Energy Corp. at this time.

Environmental Laws and Regulations

Approximately $5.3 million of the Company's capital expenditures budgeted for 2005 are to comply with environmental laws and regulations. The Company's management believes that all of its operations are in substantial compliance with present federal, state and local environmental standards. It is estimated that the Company's total expenditures for capital, operating, maintenance and other costs to preserve and enhance environmental quality will be approximately $54.3 million during 2005, as compared to approximately $52.2 million in 2004. The Company continues to evaluate its environmental management systems to ensure compliance with existing and proposed environmental legislation and regulations and to better position itself in a competitive market.

Air

On January 24, 2005, national legislation was introduced in Congress that, if passed, could require a significant reduction in emissions of sulfur dioxide ("SO2"), nitrogen oxide ("NOX") and mercury (Hg) from the electric utility industry. The legislation, introduced in Senate Bill 131, is commonly referred to as the Clear Skies Act of 2005.

While the United States has withdrawn its support of the Kyoto Protocol on global warming, legislation has been considered that would limit carbon dioxide ("CO2") emissions. In 2004, the McCain-Lieberman Climate Change Bill addressed the reduction of CO2 as a means of addressing global warming; however, the bill was defeated in the Senate. President Bush supports voluntary reductions by industry. The Company has joined other utilities in voluntary CO2 sequestration projects through reforestation of land in the southern United States. In addition, the Company has committed to reduce its CO2 emission rate (lbs. CO2/megawatt-hour) by up to five percent over the next 10 years. However, if legislation is passed requiring mandatory reductions, this could have a tremendous impact on the Company's operations by requiring the Company to significantly reduce the use of coal as a fuel source.

Other potential air regulations also have emerged that could impact the Company. On December 15, 2003, the Environmental Protection Agency ("EPA") proposed regulations to limit mercury emissions from coal-fired boilers. This rule is expected to be finalized by early 2005. Earliest compliance by the Company would be 2008. Depending upon the final regulations, this could result in significant capital and operating expenditures. In addition, on

January 30, 2004,

the EPA proposed a Clean Air Interstate Rule. This rule is intended to control SO2 and NOX from utility boilers in order to minimize the interstate transport of air pollution. The State of Oklahoma, however, is not listed as one of the states affected by the proposed rule. This, however, could change as the EPA has indicated its intentions to review Oklahoma's impact on other states. If Oklahoma is included in the final rule reductions, this could lead to significant capital and operating expenditures by the Company.

In 1997, the EPA finalized revisions to the ambient ozone and fine particulate standards. After a court challenge, which delayed implementation, the EPA has now begun to finalize the implementation process. Based on the most recent monitoring data, the EPA has designated Oklahoma "in attainment" with both standards. However, both Tulsa and Oklahoma City had previously entered into an "Early Action Compact" with the EPA whereby voluntary measures will be enacted to reduce ozone. In order to ensure that ozone levels remain below the standards, both cities intend to comply with the compact. Minimal impact on the Company's operations is expected.

In 1999, the EPA first issued regulations concerning regional haze. These regulations are intended to protect visibility in national parks and wilderness areas throughout the United States. In Oklahoma, the Wichita Mountains would be the only area covered under the regulation. However, Oklahoma's impact on parks in other states must also be evaluated. Sulfates and nitrate aerosols (both emitted from coal-fired boilers) can lead to the degradation of visibility. The State of Oklahoma has joined with eight other central states and has begun the process of determining what, if any, impact emission sources in Oklahoma have on national parks and wilderness areas. This study will be complete and any compliance strategies adopted by January 2008. If an impact is determined, then significant capital expenditures could be required for both the Sooner and Muskogee generating stations.

As required by Title IV of the Clean Air Act Amendments of 1990 ("CAAA"), the Company completed installation and certification of all required continuous emissions monitors at its generating stations in 1995. Since then, the Company has submitted emissions data quarterly to the EPA as required by the CAAA. Beginning in 2000, the Company became subject to more stringent SO2 emission requirements (Phase II of the CAAA). These lower limits had no significant financial impact due to the Company's earlier decision to burn low sulfur coal. In 2004, the Company's SO2 emissions were well below the allowable limits.

The 1990 Clean Air Act includes an emission reduction program to reduce SO2 emissions. Reductions were obtained through a program of emission (release) allowances issued by the EPA to power plants covered by the acid rain program. Each allowance is worth one ton of SO2 released from the smokestack. Plants may only release as much SO2 as they have allowances. Allowances may be banked and traded or sold nationwide. The EPA allocated sulfer dioxide allowances to the Company starting in 2000 and the Company started banking allowances in 2001. At December 31, 2004, the Company has banked approximately 31,784 allowances. In light of emerging regulations with uncertain outcomes, the Company's current strategy for management of the allowances is to bank them for future use.

With respect to the NOX regulations of Title IV of the CAAA, the Company committed to meeting a 0.45 lbs/million British thermal unit ("MMBtu") NOX emission level in 1997 on all coal-fired boilers. As a result, the Company was eligible to exercise its option to extend the effective date of the lower emission requirements from the year 2000 until 2008. The Company's average NOX emissions from its coal-fired boilers for 2004 were 0.337 lbs/MMBtu. The regulations require that the Company achieve a NOX emission level of 0.40 lbs/MMBtu for these boilers beginning in 2008. Further reductions in NOX emissions could be required if, among other things, legislation is enacted, a study currently being conducted by the state of Oklahoma determines that such NOX emissions are contributing to regional haze and that the Company's facilities impact the air quality of the Tulsa or Oklahoma City metropolitan areas, or if Oklahoma becomes non-attainment with the fine particulate standard. Any of these scenarios would require significant capital and operating expenditures.

The Oklahoma Department of Environmental Quality's ("ODEQ") Clean Air Act Amendment Title V permitting program was approved by the EPA in March 1996. By March of 1997, the Company had submitted all required permit applications. As of December 31, 2004, the Company had received Title V permits for all of its generating stations. Since these permits require renewal every five years the Company has begun the renewal process for some of its generating stations. Air permit fees for generating stations were approximately $0.6 million in 2004. The fees for 2005 are estimated to be approximately the same as in 2004.

The ODEQ is expected to adopt a new regulation dealing with the emission of toxic air contaminants. While it is unknown at this time what impact, if any, this rule will have on the Company, the rule's impact could be significant if the ODEQ identifies high concentrations of any toxic contaminants near Company facilities.

The EPA continues to investigate and enforce against electric utilities around the country for alleged violation of its New Source Review regulations. While the Company believes it has complied with all regulations, it appears that the EPA will begin investigating electric utilities in Oklahoma and surrounding states in 2005.

Waste

The Company has sought and will continue to seek, new pollution prevention opportunities and to evaluate the effectiveness of its waste reduction, reuse and recycling efforts. In 2004, the Company obtained refunds of approximately $0.8 million from its recycling efforts. This figure does not include the additional savings gained through the reduction and/or avoidance of disposal costs and the reduction in material purchases due to the reuse of existing materials. Similar savings are anticipated in future years.

Water

The Company submitted one application during 2004 to renew an Oklahoma Pollutant Discharge Elimination System ("OPDES") permit. The Company has received three renewed

wastewater permits during 2004. All permits received to date have been reasonable in their requirements, allow operational flexibility and provide reductions in operating costs.

The Company requested, based on the performance of a site-specific study, that the state agency responsible for the development of water quality standards adjust the in-stream copper criterion at one of our facilities. The state and the EPA have approved the new in-stream criteria for copper thereby avoiding costly treatment and/or facility reconfiguration requirements. Based on this approval, an OPDES permit was issued during 2004 for the facility that contains no copper limitations.

Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of any cooling water intake structure reflect the "best available technology" for minimizing environmental impacts. New EPA 316(b) rules for existing facilities became effective July 23, 2004. The Company has acquired the services of a consultant to assist in the development of "Proposal for Information Collection" documents for four applicable facilities. These documents will be submitted to the state regulatory agency for review and approval during the first or second quarters of 2005. Depending on the analysis of these final 316(b) rules, capital and/or operating costs may increase at some of the Company's generating facilities.

The Company has and will continue to evaluate the impact of its operations on the environment. As a result, contamination on Company property may be discovered from time to time.

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 Financial Statements. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of currently pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's financial position, results of operations or cash flows. This assessment of currently pending or threatened lawsuits is subject to change.

13. Rate Matters and Regulation

Regulation and Rates

The Company's retail electric tariffs are regulated by the OCC in Oklahoma and by the APSC in Arkansas. The issuance of certain securities by the Company is also regulated by the OCC and the APSC. The Company'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 the Company's facilities and operations. For the year ended December 31, 2004, approximately 87 percent of the Company's electric revenue was subject to the jurisdiction of the OCC, nine percent to the APSC and four percent to the FERC.

The OCC issued an order in 1996 authorizing the Company to reorganize into a subsidiary of Energy Corp. The order required that, among other things, (i) Energy Corp. permit the OCC access to the books and records of Energy Corp. and its affiliates relating to transactions with the Company; (ii) Energy Corp. employ accounting and other procedures and controls to protect against subsidization of non-utility activities by the Company's customers; and (iii) Energy Corp. refrain from pledging the Company assets or income for affiliate transactions.

Recent Regulatory Matters

2002 Settlement Agreement

On November 22, 2002, the OCC signed a rate order containing the provisions of a Settlement Agreement of the Company's rate case. The Settlement Agreement provides for, among other items: (i) a $25.0 million annual reduction in the electric rates of the Company's Oklahoma customers which went into effect January 6, 2003; (ii) recovery by the Company, through rate base, of the capital expenditures associated with the January 2002 ice storm; (iii) the Company to acquire electric generation of not less than 400 MWs ("New Generation") to be integrated into the Company's generation system; and (iv) recovery by the Company, over three years, of the $5.4 million in deferred operating costs, associated with the January 2002 ice storm, through the Company's rider for off-system sales. Previously, the Company had a 50/50 sharing mechanism in Oklahoma for any off-system sales. The Settlement Agreement provided that the first $1.8 million in annual net profits from the Company's off-system sales will go to the Company, the next $3.6 million in annual net profits from off-system sales will go to the Company's Oklahoma customers, and any net profits of off-system sales in excess of these amounts will be credited in each sales year with 80 percent to the Company's Oklahoma customers and the remaining 20 percent to the Company. If any of the $5.4 million is not recovered at the end of the three years, the OCC will authorize the recovery of any remaining costs. During the year ended December 31, 2004, the Company recovered approximately $1.8 million in annual net profits from off-system sales, gave approximately $3.6 million in annual net profits from off-system sales to the Company's Oklahoma customers and the net profits from off-system sales that exceeded the $5.4 million were shared with 80 percent to the Company's Oklahoma customers and the remaining 20 percent to the Company.

OCC Order Confirming Savings

The Settlement Agreement required that, if the Company did not acquire the New Generation by December 31, 2003, the Company must credit $25.0 million annually (at a rate of 1/12 of $25.0 million per month for each month that the New Generation is not in place) to its Oklahoma customers beginning January 1, 2004 and continuing through December 31, 2006. As discussed in more detail below, in August 2003 the Company signed an agreement to purchase a

77 percent interest in the McClain Plant, but due to a delay at the FERC, the acquisition was not completed by December 31, 2003. In the interim, the Company entered into a power purchase agreement with the McClain Plant that delivered the savings guaranteed to the Company's customers. The Company requested that the OCC confirm that the steps it had taken, including the power purchase agreement, were satisfying the customer savings obligation under the Settlement Agreement and that the Company would not be required to begin crediting its customers. On April 28, 2004, the OCC issued an order confirming that the Company was delivering savings to its customers as required under the Settlement Agreement. The order removed any uncertainty over whether the OCC believed the Company had to reduce its rates, effective January 1, 2004, while it awaited action by the FERC on its application to purchase the McClain Plant. A party to the OCC proceeding has appealed the OCC's order to the Oklahoma Supreme Court. The Company currently believes that the appeal is without merit.

Recent Acquisition of Power Plant

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

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

The final approval the Company had been waiting for was the approval from the FERC. On July 2, 2004, the FERC authorized the Company to acquire the McClain Plant. The FERC's approval was based on an offer of settlement the Company filed in a proceeding on March 8, 2004. Under the offer of settlement, the Company proposed, among other things, to install certain new transmission facilities and to hire an independent market monitor to oversee the Company's activity for a limited period. Two other parties, InterGen Services, Inc. and AES Shady Point, opposed the Company's offer of settlement and filed competing settlement offers. In the July 2, 2004 order, the FERC: (i) approved the Company's offer of settlement subject to conditions; (ii) rejected the competing offers of settlement; and (iii) approved the Company's acquisition of the McClain Plant. As part of the July 2, 2004 order, the Company agreed to undertake the following mitigation measures: (i) install a transformer at one of its facilities at a cost of approximately $9.3 million which was completed in the fourth quarter of 2004; (ii) provide a 600 MW bridge into its control area from the Redbud Energy LP ("Redbud") plant; and (iii) hire an independent market monitor to oversee the Company's activity in its control area.

The market monitoring plan is designed to detect any anticompetitive conduct by the Company from operation of its generation resources or its transmission system. The market monitoring function is performed daily and periodic reviews are also performed. To date, the independent market monitor has filed two reports, one on October 13, 2004 covering the period from July 10, 2004 to September 30, 2004, and one on January 14, 2005 covering the period from October 1, 2004 to December 31, 2004. Based on an analysis of transmission congestion data on the Company's system, along with data on purchases and sales, generation dispatch data and power flows on the Company's tie lines, the market monitor concluded that the Company did not act in an anticompetitive manner through either dispatch of its generation or operation of its transmission system. Additionally, the Company's operations under the ongoing mitigation measures that require the Company to make available transmission capability available to the Redbud power plant for access to the Company system were analyzed. Based on this analysis, the market monitor concluded that the Company has complied with this requirement. Further, in the review of the disposition of requests for transmission service, the independent market monitor detected no problems with access to the Company's transmission system. The Company expects to complete the installation and implementation of these measures by June 2005. One party has filed a request for rehearing of the FERC's July 2, 2004 order. The outcome of that request for rehearing cannot be determined at this time.

The Company is operating the plant in accordance with a joint ownership and operating agreement with the OMPA. Under this agreement, the Company operates the facility, and the Company and the OMPA are entitled to the net available output of the plant based on their respective ownership percentages. All fixed and variable costs, except fuel and gas transportation costs, are shared in proportion to the respective ownership interests. Fuel and gas transportation costs are paid in accordance with each individual owner's respective transportation contract and consumption. The Company expects to utilize its portion of the output, 400 MWs, to serve its native load. As a result, the Company expects to file with the OCC a request to increase its rates to its Oklahoma customers to recover, among other things, its investment in, and the operating expenses of, the McClain Plant no later than July 8, 2005. The Company expects to file a rate case during the second quarter of 2005 using 2004 as a test year with new approved rates expected to be in effect by January 2006. As provided in the Settlement Agreement, until the Company seeks and obtains approval of a request to increase base rates to recover, among other things, the investment in the plant, the Company will have the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the acquisition and operation of the McClain Plant, consisting of the non-fuel operation and maintenance expenses, depreciation, cost of debt associated with the investment and ad valorem taxes. If the OCC were to approve the Company's request, all prudently incurred costs accrued through the regulatory asset within the 12-month period would be included in the Company's prospective cost of service and would be recovered over a period to be determined by the OCC.

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

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

Contract with PowerSmith

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

Security Enhancements

On April 8, 2002, the Company filed a joint application with the OCC requesting approval for security investments and a rider to recover these costs from the ratepayers. On August 14, 2002, the Company filed testimony with the OCC outlining proposed expenditures and related actions for security enhancement and a proposed recovery rider. Attempting to make security investments at the proper level, the Company 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 the Company that might be caused by an attack and accomplish these efforts with minimal impact on ratepayers. The OCC Staff retained a security expert to review the report filed by the Company. On July 13, 2004, the security expert filed testimony that recommended: (i) $19.0 million in capital expenditures and $2.5 million annually in operating and maintenance expenses are justified to enhance the security of the Company's infrastructure; and (ii) a security rider should be authorized to recover costs as these projects are completed. On August 4, 2004, the Company filed responsive testimony that quantified the minimal customer

impact and revised its request for security investments so that it was consistent with the OCC Staff's recommendations. On August 13, 2004, the only intervening party, the Oklahoma Industrial Energy Consumers ("OIEC"), filed a statement of position which supported the OCC Staff's recommendations. On October 28, 2004, all parties signed a joint stipulation that contains the OCC Staff's recommendations and authorizes up to a $5 million annual recovery from the Company's customers for security enhancement. The hearing in this case was held on November 9, 2004, at which time the administrative law judge approved the stipulation agreement between all parties. On December 21, 2004 the OCC issued an order approving the security rider.

On October 17, 2003, the OCC filed a notice of inquiry to consider the issues related to the role of the OCC and Oklahoma regulated companies in addressing the security of the utility system infrastructure and key assets. On March 4, 2004, the OCC deliberated the notice of inquiry and directed the OCC Staff to file a rulemaking proceeding for each utility industry regarding security of the utility system infrastructure and key assets. On August 27, 2004, the OCC Staff filed a Notice of Proposed Rulemaking. The first technical conference was held on September 23, 2004 and written comments were filed by all the parties on October 1, 2004. A second technical conference was held on October 21, 2004. The hearing in this case was held on December 3, 2004. On December 10, 2004, the OCC submitted the amended rules to the Governor's Office and Oklahoma Legislature.

Cogeneration Credit Rider

On September 17, 2004, the Company filed an application and testimony with the OCC requesting a cogeneration credit rider. The requested rider would reduce charges to customers because of decreasing cogeneration payments made by the Company beginning January 2005. The cogeneration credit rider is necessary because amounts currently recovered from customers in base rates include historically higher cogeneration payments. The Company's current cogeneration credit rider expired December 31, 2004. On October 29, 2004, the OCC Staff and other parties filed responsive testimony. Hearings in this case were held on November 15, 2004, at which time the administrative law judge recommended approval of the proposed cogeneration credit rider. On December 21, 2004 the OCC issued an order approving the new cogeneration credit rider which will lower electric bills by approximately $80 million annually.

Pending Regulatory Matters

Currently, the Company has one significant matter pending at the OCC which is a review of the process completed by the Company in its selection of gas transportation and storage services to meet its system operating needs. This matter, as well as several other matters pending before the FERC, are discussed below.

Gas Transportation and Storage Agreement

As part of the Settlement Agreement, the Company also agreed to consider competitive bidding as a basis to select its provider for gas transportation service to its natural gas-fired

generation facilities pursuant to the terms set forth in the Settlement Agreement. The prescribed bidding process detailed in the Settlement Agreement provided that each generation facility seek bids separately for the services required. The Company believes that in order for it to achieve maximum coal generation, which delivers the lowest cost energy to its customers, and ensure reliable electric service, it must have integrated, firm no-notice load following service for both gas transportation and gas storage. This type of service is required to satisfy the daily swings in customer demand placed on the Company's system and still permit natural gas units to not impede coal energy production. The Company also believes that gas storage is an integral part of providing gas supply to the Company's generation facilities. Accordingly, the Company evaluated its competitive bid options in light of these circumstances. The Company's evaluation clearly demonstrates that the Enogex integrated gas system provides superior integrated, firm no-notice load following service to the Company that is not available from other companies serving the Company marketplace.

On April 29, 2003, as required by the Settlement Agreement, the Company filed an application with the OCC in which the Company advised the OCC that, after careful consideration, competitive bidding for gas transportation was rejected in favor of a new intrastate integrated, firm no-notice load following gas transportation and storage services agreement with Enogex. This seven-year agreement provides for gas transportation and storage services for each of the Company's natural gas-fired generation facilities. The Company will pay Enogex annual demand fees of approximately $46.8 million for the right to transport specified maximum daily quantities ("MDQ") and maximum hourly quantities ("MHQ") of gas at various minimum gas delivery pressures depending on the operational needs of the individual generating facility. In addition, the Company supplies system fuel in-kind for its pro-rata share of actual fuel and loss and unaccounted for gas on the transportation system. To the extent the Company transports gas in quantities in excess of the prescribed MDQs or MHQs, it pays an overrun service charge. During the years ended December 31, 2004, 2003 and 2002, the Company paid Enogex approximately $49.6 million, $44.7 million and $36.9 million, respectively, for gas transportation and storage services.

Based upon requests for information from intervenors, the Company requested from Enogex and Enogex retained a "cost of service" consultant to assist in the preparation of testimony related to this case. On March 31, 2004, the Company filed testimony and exhibits with the OCC, which completed the initial documentation required to be filed in this case. On July 12, 2004, several parties filed responsive testimony reflecting various positions on the issues related to this case. In particular, the testimony of the OCC Staff recommended that the Company be entitled to recover the $46.8 million annual demand fee requested, which results in no refund, and also recommended that the Company provide at its next general rate review the results of an open competitive bidding process or a comprehensive market study. If the Company does not provide such open bidding or market study, the OCC Staff recommendation would cap recovery at approximately $40 million at the Company's next general rate review. The recommendations in the testimony of the Attorney General's office and the OIEC would cap recovery at approximately $35 million and $30 million, respectively, with the difference between what the Company has been collecting through its automatic fuel adjustment clause and these recommended amounts being refunded to customers.

The Company filed rebuttal testimony on August 16, 2004 in this case. Hearings in this case before an administrative law judge occurred from September 16-22, 2004. On October 22, 2004, the administrative law judge overseeing the proceeding recommended approximately $41.9 million annual demand fee recovery with the Company refunding to its customers any demand fees collected in excess of this amount. If this recommendation is ultimately accepted, the Company believes its refund obligation would be approximately $6.9 million at December 31, 2004, which the Company does not believe is material in light of previously established reserves. The Company believes the amount currently paid to Enogex for integrated, firm no-notice load following transportation and storage services is fair, just and reasonable. The Company and other parties to the proceeding appealed the administrative law judge's recommendation on November 1, 2004 and a hearing in this case was held before the OCC on December 7, 2004. The OCC took the case under advisement and an OCC order in the case is expected in the first quarter of 2005. There can be no guarantee that the OCC will approve the $41.9 million annual demand fee recovery recommended by the administrative law judge.

Southwest Power Pool

The Company is a member of the Southwest Power Pool ("SPP"), the regional reliability organization for all or parts of Oklahoma, Arkansas, Kansas, Louisiana, New Mexico, Mississippi, Missouri and Texas. The Company participated with the SPP in the development of regional transmission tariffs and executed a Membership Agreement with the SPP to facilitate interstate transmission operations within this region in 1998. In October 2003, the SPP filed an application with the FERC seeking authority to form a regional transmission organization ("RTO"). On February 10, 2004, the FERC conditionally approved the SPP's application. The SPP must meet certain conditions before it may commence operations as an RTO. On April 27, 2004, the SPP Board of Directors took actions to meet the conditions to satisfy the FERC requirement for formal approval of the RTO. The SPP compliance filing at the FERC was made on May 3, 2004. In response to a subsequent FERC order on July 2, 2004, the SPP made a compliance filing on August 6, 2004 stating that all requirements had been met to achieve RTO status. In a FERC order dated October 1, 2004, the FERC accepted the SPP's compliance filing and the SPP was granted RTO status, subject to the SPP submitting a further compliance filing, within 30 days. On November 1, 2004, the SPP made a compliance filing as required under the October 1 FERC order. Also, on November 1, the SPP filed a request for rehearing of the FERC's October 1 order. On December 1, 2004, the FERC granted the request for rehearing. On January 25, 2005, the FERC issued an order on compliance filing stating that the November 1, 2004 SPP compliance filing satisfied the October 1 FERC order. The recent approval of the SPP RTO application is not expected to significantly impact the Company's financial results.

Currently, the regional state committee, which is comprised of commissioners regulating the state regulatory jurisdictional SPP members, is in the process of formulating a methodology for funding transmission expansion in the SPP's control area by allocating costs of transmission expansion to the SPP members who benefit. The SPP plans to make a filing at the FERC in February 2005 related to this matter. Also, the SPP is in the process of developing a process, required by the FERC, to create an imbalance energy market which will require cash settlements

for over or under generation. Each SPP member will be responsible for monitoring its generation in its control area on an hourly basis and periodically submitting this information to the SPP, who will then provide settlement statements to each of the SPP members. The imbalance energy market requirements are planned to be effective October 1, 2005.

FERC Standards of Conduct

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

In February 2004, the Company and Enogex submitted plans and schedules to the FERC which detail the necessary actions to be in compliance with these new rules and expected that their initial costs to comply with the final rules would not exceed $1.6 million in 2004. On April 16, August 2 and December 21, 2004, the FERC issued orders on rehearing in which the FERC largely rejected requests to revise its November 25, 2003 final rule. However, the FERC did extend the compliance date until September 22, 2004 and did clarify certain aspects of the rule.

The Company and Enogex believe that they have taken the necessary actions to comply with the new rules. The initial cost of compliance incurred in 2004 was less than $0.5 million. Additionally, the Company and Enogex believe that the recurring cost of compliance in future years will be immaterial to Energy Corp.

Market-Based Rate Authority

On December 22, 2003, the Company and OGE Energy Resources, Inc. ("OERI") filed a triennial market power update based on the supply margin assessment test. On April 14, 2004, the FERC issued: (1) interim requirements for the FERC jurisdictional electric utilities who have been granted authority to make wholesale sales at market-based rates; and (2) an order initiating a new rulemaking on future market-based rates authorizations. The interim method for analyzing generation market power requires two assessments – whether the utility is a pivotal supplier based on a control area's annual peak demand and whether the utility exceeds certain market share thresholds on a seasonal basis. If an applicant fails to pass either assessment, the FERC will presume that the utility can exercise generation market power and will initiate an investigation into the scope of the applicant's market power. The FERC will allow a utility to rebut that presumption through the submission of additional information. If an applicant is found to have generation market power, the applicant must propose a market power mitigation plan. The new interim assessment methods are applicable to all pending initial market-based rate applications and triennial reviews pending the rulemaking described below. On May 13, 2004, the FERC directed all utilities with pending three year market-based reviews to revise the generation market power portion of their three year review to address the two interim tests described above. In the rulemaking proceeding, the FERC is seeking comments on the adequacy

of the FERC's current analysis of market-based rate filings, including the adequacy of the new "interim" assessment of generation market power. The Company and OERI submitted a compliance filing to the FERC on February 7, 2005 which shows the impact of the new requirements on the Company and OERI. In the compliance filing, the Company and OERI passed the pivotal supplier screen but failed to pass the market share screen. The Company and OERI provided an explanation as to why its failure of the market share screen should not be viewed as an indication that they can exercise generation market power. The Company and OERI do not know when the FERC will act on the filing or what action the FERC will take.

Department of Energy Blackout Report

On April 5, 2004, the U.S. Department of Energy issued its final report regarding the August 14, 2003 electric blackout in the eastern United States, which did not have an adverse affect on the Company's electric system. The report recommends a number of specific changes to current statutes, rules or practices in order to improve the reliability of the infrastructure used to transmit electric power. The recommendations include the establishment of mandatory reliability standards and financial penalties for noncompliance. On April 14, 2004, the FERC issued a policy statement requiring electric utilities, including the Company, to submit a report on vegetation management practices and indicating the FERC's intent to make North American Electric Reliability Council reliability standards mandatory. On June 17, 2004, the Company filed its report on vegetation management practices with the FERC. During 2004, the Company spent less than $0.2 million related to the implementation of blackout report recommendations. Implementation of the blackout report recommendations and the FERC policy statement could increase future transmission costs, but the extent of the increased costs is not known at this time.

Redbud Tariff Filing

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

National Energy Legislation

In December 2004, the 108th Congress concluded without enactment of a comprehensive energy bill that had been debated in the Senate and the House of Representatives during 2003 and 2004. While the House had given strong support to the bill, the Senate failed to overcome a filibuster which blocked final passage. The bill, as it came out of the House-Senate conference, would have been largely beneficial to the Company. It contained provisions that would have minimized the risk of future uneconomic purchased power contracts being forced on the Company under PURPA, and provided tax incentives for investment in the electric transmission and natural gas pipeline systems. The bill also provided favorable provisions for mandatory reliability regulation by the North American Electric Reliability Council with oversight by the FERC, and contained improved FERC siting authority for construction of electric transmission in disputed areas. Also deemed positive by the Company was the fact that the bill did not contain any provisions for federal mandates of renewable energy which would have had the effect of raising the Company's electric rates. Another significant provision of the energy bill was the repeal of the Public Utility Holding Company Act of 1935 which was of minimal impact to the Company.

While Congress did not enact the comprehensive energy bill in 2004, Congress was able to pass some elements of that comprehensive bill as parts of other legislation. In particular, in the Foreign Sales Corporation – Extra-Territorial Income bill, Congress enacted some provisions relating to the reauthorization of the expired tax credits for renewable energy projects, including wind turbines, and permitted utilities to deduct a percentage of their generation revenue as "manufacturers" of energy.

Looking to the 109th Congress in 2005, the Republican congressional leadership and the Bush Administration have indicated that enactment of a comprehensive energy bill remains a priority. While the precise contours of that legislation to be considered in 2005 remain unknown at this time, many observers anticipate that a bill basically following the substance of the energy bill that was nearly passed in the 108th Congress, with some modifications, will serve as the vehicle.

Federal law imposes numerous responsibilities and requirements on the Company. PURPA requires electric utilities, such as the Company, to purchase power generated in a manufacturing process from a QF. Generally stated, electric utilities must purchase electric energy and production capacity made available by QFs at a rate reflecting the cost that the purchasing utility can avoid as a result of obtaining energy and production capacity from these sources rather than generating an equivalent amount of energy itself or purchasing the energy or capacity from other suppliers. The Company has entered into agreements with four such cogenerators. Electric utilities also must furnish electric energy on a non-discriminatory basis at a rate that is just, reasonable and in the public interest and must provide certain types of service which may be requested by QFs to supplement or back up those facilities' own generation.

Although efforts to increase competition at the state level have been stalled, there have been several initiatives implemented at the federal level to increase competition in the wholesale markets for electricity. The National Energy Policy Act of 1992 (“Energy Act”), among other things, promoted the development of independent power producers (“IPP”). The Energy Act was followed by FERC Order 888 and Order 889, which facilitated third-party utilization of the transmission grid for sales of wholesale power. The Energy Act, Orders 888 and 889, and other FERC policies and initiatives have significantly increased competition in the wholesale power market. Utilities, including the Company, have increased their own in-house wholesale marketing efforts and the number of entities with whom they historically traded. While power marketers became an increasingly important presence in the industry, their importance has declined following the bankruptcy of Enron and the financial troubles of other significant power marketers. These entities typically arbitrage wholesale price differentials by buying power produced by others in one market and selling it in another. IPPs also are becoming a more significant sector of the electric utility industry. In both Oklahoma and Arkansas, significant additions of new power plants have been announced and, in some cases completed, almost all of it from IPPs.

Notwithstanding these developments in the wholesale power market, the FERC recognized that impediments remained to the achievement of fully competitive wholesale markets including: (i) engineering and economic inefficiencies inherent in the current operation and expansion of the transmission grid; and (ii) continuing opportunities for transmission owners (primarily electric utilities) to discriminate in the operation of their transmission facilities in favor of their own or affiliated power marketing activities. In the past, the FERC only encouraged utilities to join and place their transmission systems under the operational control of independent system operators. On December 20, 1999, the FERC issued Order 2000, its final rule on RTOs. Order 2000 is intended to have the effect of turning the nation’s transmission facilities into independently operated “common carriers” that offer comparable service to all would-be-users. Although adopting a voluntary approach towards RTO formation, the FERC stressed that Order 2000 does not preclude it from requiring RTO participation. Order 2000 set out a timetable for every jurisdictional utility (including the Company) to either join in an RTO filing, or, alternatively, to submit a filing describing its efforts to join an RTO, the reasons for not participating in an RTO proposal and any obstacles to participation, and its plans for further work toward participation. In October 2004, the FERC gave its approval to the creation of the SPP RTO, of which the Company is a member.

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 electric 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 proposed rule contemplates that all wholesale and retail customers will take transmission service under 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. On April 28, 2003, the FERC issued a White Paper, “Wholesale Market Platform”, in which the FERC indicated that it will change the proposed rule as reflected in the White Paper and following additional regional technical conferences. 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. Thus far, the FERC has held conferences in Boston, Omaha, Wilmington, Tallahassee, Phoenix, New York, Dallas, Atlanta and San Francisco.

On April 14, 2004, the FERC initiated Docket No. RM04-7 to review its generation market power screening processes. The existing four-prong test was developed over 15 years in what the FERC characterizes as a different marketplace than today. The FERC plans to review the continued appropriateness of the four-prong test and consider amendments and additions to the required tests. On May 11, 2004, the FERC opened Docket No. PL04-6 establishing an investigation of best practices for competitive solicitation methods for public utilities, including public utility sales to affiliates. The purpose of this investigation is to ensure that transactions filed with the FERC are the result of a fair and open procedure. On October 6, 2004, the FERC established Docket No. RM04-14 to set guidelines for events that would trigger a reporting obligation on the part of any public utility with the authority to engage in sales for resale of electric energy in interstate commerce at market-based rates and possibly modify the market-based rate authority for public utilities that had a qualifying change in status that would affect their relevant market power. On February 10, 2005, the FERC issued Order 652 related to Docket RM04-14. The Company is currently evaluating Order 652 to determine the impact on the Company. Although technical conferences have been held for the first two of these dockets, to date no definitive rules or guidance have been issued by the FERC. Dockets RM04-7 and PL04-6 remain open. Any of these dockets may have a material effect upon the Company’s participation in wholesale energy markets.

In October 2003, the FERC issued new rules governing corporate “money pools,” which include jurisdictional public utility or pipeline subsidiaries of nonregulated parent companies. The rules require documentation of transactions within such money pools and notification to the FERC if the common equity ratio of the utility falls below 30 percent.

The FERC requires all utilities authorized to sell power at market-based rates to file updated market power analyses every three years. In December 2003, the Company filed its updated market power analysis with the FERC.

State Legislative Initiatives

Oklahoma

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

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

In the 2004 legislative session, legislation was enacted requiring a study to determine the feasibility of providing investor-owned utilities an incentive to enter into purchase power agreements in Oklahoma by allowing the utilities to earn a return on purchased power. The study committee held its first meeting in August and continued holding two meetings a month through November. At the conclusion of the meetings, the study committee determined that the final report would make no recommendations to the legislature in January 2005.

Arkansas

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

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

As discussed above, legislation was enacted in Oklahoma and Arkansas that was to restructure the electric utility industry in those states. The Arkansas legislation was repealed and implementation of the Oklahoma restructuring legislation has been delayed and seems unlikely to proceed during the near future. Yet, if and when implemented, this legislation could deregulate the Company's electric generation assets and cause the Company to discontinue the use of SFAS No. 71 with respect to its related regulatory balances. This may result in either full recovery of generation-related regulatory assets (net of related regulatory liabilities) or a non-cash, pre-tax write-off as an extraordinary charge, depending on the transition mechanisms developed by the legislature for the recovery of all or a portion of these net regulatory assets.

The previously enacted Oklahoma and Arkansas legislation would not affect the Company's electric transmission and distribution assets and the Company believes that the continued use of SFAS No. 71 with respect to the related regulatory balances is appropriate. However, if utility regulators in Oklahoma and Arkansas were to adopt regulatory methodologies in the future that are not based on the cost-of-service, the continued use of SFAS No. 71 with respect to the regulatory balances related to the electric transmission and distribution assets may no longer be appropriate. Based on a current evaluation of the various factors and conditions that are expected to impact future cost recovery, management believes that its regulatory assets, including those related to generation, are probable of future recovery.

Summary

The Energy Act, the actions of the FERC, the restructuring legislation in Oklahoma and other factors are intended to increase competition in the electric industry. The Company has taken steps in the past and intends to take appropriate steps in the future to remain a competitive supplier of electricity. While the Company is supportive of competition, it believes that all electric suppliers must be required to compete on a fair and equitable basis and the Company is advocating this position vigorously.

14. 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, as of December 31:

	2004		2003	
(In millions)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Price Risk Management Assets				
Interest Rate Swap	**$ 3.9**	**$ 3.9**	$ 4.0	$ 4.0
Long-Term Debt				
Senior Notes	**$ 711.8**	**$ 764.2**	$ 571.8	$ 611.8
Industrial Authority Bonds	**135.4**	**135.4**	135.4	135.4

The carrying value of the financial instruments on the Balance Sheets not otherwise discussed above approximates fair value except for long-term debt which is valued at the carrying amount. The valuation of the Company's interest rate swap was determined primarily based on quoted market prices. The fair value of the Company's long-term debt is based on quoted market prices.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholder
Oklahoma Gas and Electric Company

We have audited the accompanying balance sheets and statements of capitalization of Oklahoma Gas and Electric Company as of December 31, 2004 and 2003, and the related statements of income, retained earnings, comprehensive income and cash flows for each of the three years in the period ended December 31, 2004. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Oklahoma Gas and Electric Company at December 31, 2004 and 2003, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2004, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth herein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Oklahoma Gas and Electric Company's internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 23, 2005 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 23, 2005

Supplementary Data

Interim Financial Information (Unaudited)

In the opinion of the Company, the following quarterly information includes all adjustments, consisting of normal recurring adjustments, necessary for a fair statement of the results of operations for such periods:

Quarter ended *(In millions)*		Dec 31	Sep 30	Jun 30	Mar 31
Operating revenues	**2004**	**$ 326.4**	**$ 535.9**	**$ 411.5**	**$ 304.3**
	2003	286.3	540.3	357.9	332.6
Operating income (loss)	**2004**	**$ (15.1)**	**$ 147.4**	**$ 54.7**	**$ 5.0**
	2003	(2.0)	160.8	55.3	2.1
Net income (loss)	**2004**	**$ (14.1)**	**$ 91.3**	**$ 30.4**	**$ ---**
	2003	(4.3)	95.1	27.9	(3.3)

Security Ratings*

	Moody's	Standard & Poor's	Fitch's
Company Senior Notes	A2	BBB+	AA-

* The ratings of Moody's, Standard & Poor's and Fitch's reflect only the views of such organizations and each rating should be evaluated independently of the other. The ratings are not recommendations to buy, sell or hold securities. Such ratings may be subject to revision or withdrawal at any time by the credit rating agency. Moody's, Standard & Poor's and Fitch's currently maintain a stable outlook on its ratings of the Company's Senior Notes.

For further information regarding these ratings, please contact the Treasurer of the Company at 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321, (405) 553-3800.

Item 9. Changes In and Disagreements with Accountants on Accounting and Financial Disclosure.

None.

Item 9A. Controls and Procedures.

The Company maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of the Company's management, including the Chief Executive Officer

("CEO") and Chief Financial Officer ("CFO"), of the effectiveness of the Company's disclosure controls and procedures, the CEO and CFO have concluded that the Company's disclosure controls and procedures are effective.

No change in the Company's internal control over financial reporting has occurred during the Company's most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting.

Management's Report on Internal Control Over Financial Reporting

The management of Oklahoma Gas and Electric Company (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control system was designed to provide reasonable assurance to the Company's management and Board of Directors regarding the preparation and fair presentation of published financial statements. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2004. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework. Based on our assessment, we believe that, as of December 31, 2004, the Company's internal control over financial reporting is effective based on those criteria.

The Company's independent auditors have issued an attestation report on management's assessment of the Company's internal control over financial reporting. This report appears on the following page.

/s/ Steven E. Moore	/s/ Peter B. Delaney
Steven E. Moore, Chairman of the Board, President and Chief Executive Officer	Peter B. Delaney, Executive Vice President and Chief Operating Officer
/s/ James R. Hatfield	/s/ Donald R. Rowlett
James R. Hatfield, Senior Vice President and Chief Financial Officer	Donald R. Rowlett, Vice President and Controller

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholder
Oklahoma Gas and Electric Company

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that Oklahoma Gas and Electric Company maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Oklahoma Gas and Electric Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, management's assessment that Oklahoma Gas and Electric Company maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, Oklahoma Gas and Electric Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2004, based on the COSO criteria**.**

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the balance sheets and statements of capitalization of Oklahoma Gas and Electric Company as of December 31, 2004 and 2003, and the related statements of income, retained earnings, comprehensive income and cash flows for each of the three years in the period ended December 31, 2004 of Oklahoma Gas and Electric Company and our report dated February 23, 2005 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 23, 2005

Item 9B. Other Information.

None.

PART III

Item 10. Directors and Executive Officers of the Registrant.

Item 11. Executive Compensation.

On February 23, 2005 the Compensation Committee (the "Committee") of the Board of Directors of OGE Energy Corp. (in this Item 11, the "Company") took certain actions regarding executive officer and director compensation. Set forth below is a description of the actions taken. The Committee also made minor changes to the compensation of directors and salaries of its executive officers at its meeting on November 17, 2004, which also are described below.

Approve Payout of 2004 Annual Incentive Awards

In January 2004, the Committee established awards under the Company's Annual Incentive Compensation Plan, which was approved by shareowners at the 2003 Annual Meeting, for executive officers and certain other employees of the Company.

The amount of the award for each executive officer was expressed as a percentage of base salary (the "targeted amount"), with the officer having the ability, depending upon achievement of the corporate goals, to receive from 0% to 150% of such targeted amount. For 2004, the targeted amount ranged from 25% to 75% of base salary. Payouts of the award were to be in cash and were dependent entirely on the achievement of the corporate goals.

The percentage of the targeted amount that an officer ultimately received based on corporate performance was subject to being decreased, but not increased, at the discretion of the Committee.

For Mr. Steven E. Moore, Chairman and Chief Executive Officer, Mr. A.M. Strecker, former Executive Vice President and Chief Operating Officer, and Mr. Peter B. Delaney, Executive Vice President and Chief Operating Officer, the three most senior executive officers of the Company at the time the corporate goals were established, the corporate goals were based: (i) 50% on a Company consolidated earnings per share target established by the Committee (the "2004 Earnings Target"), (ii) 25% on a combined operating and maintenance expense and capital expenditure target for the Company and OG&E established by the Committee (the "2004 O&M/Capital Target"), and (iii) 25% on consolidated net income of Enogex and its subsidiaries (the "2004 Unregulated Income Target"). These three corporate goals were also used in establishing the corporate goals for all other executive officers. However, the weighting of the goals was slightly different for the remaining executive officers, with the corporate goals for one executive officer being based

50% on the 2004 Earnings Target and 50% on the 2004 O&M/Capital Target while for the remaining executive officers the corporate goals were based 50% on the 2004 Earnings Target, with the remaining 50% allocated between the 2004 O&M/Capital Target and the 2004 Unregulated Income Target based on the responsibilities of the individual's position.

Corporate performance of the 2004 Earnings Target, the 2004 O&M/Capital Target and the 2004 Unregulated Income Target exceeded the minimum levels of achievement established by the Committee and, consequently, the Committee on February 23, 2005 approved payouts under the Annual Incentive Plan to executive officers ranging from 32.3% to 99.5% of their base salaries and from approximately 115% to 133% of their targeted amounts.

The payouts for the six most highly compensated executive officers of the Company are as follows:

	Payout as % of Target	Payout
Steven E. Moore	132.72%	$ 706,747
A.M. Strecker	132.72%	$ 165,350
Peter B. Delaney	132.72%	$ 350,387
James R. Hatfield	129.27%	$ 200,364
Jack T. Coffman	115.45%	$ 120,063
Steven R. Gerdes	117.00%	$ 77,220

2005 Compensation for Executive Officers

Executive compensation for 2005 consists of salary, annual awards under the Company's Annual Incentive Compensation Plan and long-term awards under the Stock Incentive Plan. Compensation levels were set by the Committee after consideration of, among other things, individual performance and market-based data on compensation for executives with similar duties. Payments of 2005 annual and long-term awards will be dependent upon achievement of specified goals set by the Committee and discussed below. No officer is assured of any payment of annual or long-term awards.

Salary

The Committee made modest changes to the existing base salaries of its senior executive group.

	2005 Base Salary	% Increase
Steven E. Moore	$750,000	5.63%
Peter B. Delaney	$475,000	7.95%
James R. Hatfield	$315,000	1.61%
Jack T. Coffman	$265,000	1.92%
Steven R. Gerdes	$220,000	0%

Annual Incentive Awards

The Committee established awards for 2005 under the Company's Annual Incentive Compensation Plan, which was approved by shareowners at the 2003 Annual Meeting, for executive officers and certain other employees of the Company.

The amount of the award for each executive officer was expressed as a percentage of base salary (the "targeted amount"), with the officer having the ability, depending upon achievement of the corporate goals, to receive from 0% to 150% of such targeted amount. For 2005, the targeted amount ranged from 25% to 75% of base salary. Payouts of the award are to be in cash and are dependent entirely on the achievement of the corporate goals.

The percentage of the targeted amount that an officer ultimately received based on corporate performance is subject to being decreased, but not increased, at the discretion of the Committee.

For Mr. Steven E. Moore, Chairman and Chief Executive Officer, and Mr. Peter B. Delaney, Executive Vice President and Chief Operating Officer, the two most senior executive officers of the Company at the time the corporate goals were established, the corporate goals were based: (i) 50% on a Company consolidated earnings per share target established by the Committee (the "2005 Earnings Target"), (ii) 25% on a combined operating and maintenance expense and capital expenditure target for the Company and OG&E established by the Committee (the "2005 O&M/Capital Target"), and (iii) 25% on consolidated net income of Enogex and its subsidiaries (the "2005 Unregulated Income Target"). These three corporate goals were also used in establishing the corporate goals for all other executive officers. However, the weighting of the goals was slightly different for the remaining executive officers, with the corporate goals for four executive officers being based 50% on the 2005 Earnings Target and 50% on the 2005 O&M/Capital Target while for the remaining executive officers the corporate goals were based 50% on the 2005 Earnings Target, with the remaining 50% allocated between the 2005 O&M/Capital Target, the 2005 Unregulated Income Target and a return on invested capital goal for the unregulated business, based on the responsibilities of the individual's position.

Long-Term Awards

For 2005, the Committee made awards of performance units. The number of performance units granted was determined by taking the amount of the executive's long-term award to be delivered in performance units (adjusted on a present value basis), as determined by the Committee, and dividing that amount by the closing price for the Company's Common Stock on January 3, 2005 with a vesting factor applied. This resulted in executives receiving performance units with an expected value at the date of grant of from 25% to 150% of their 2005 base salaries. The value of the performance units is substantially dependent upon the changing value of the Company's Common Stock in the marketplace. Each executive officer is entitled to receive from 0% to 200% of the performance units contingently awarded to the executive depending upon corporate performance. For 75% of the performance units, this corporate

performance will be based on the Company's total shareholder return over a three-year period (defined as share price increase plus dividends paid, divided by share price at beginning of the period) measured against the total shareholder return for such period by a peer group selected by the Committee. For the remaining 25% of the performance units, the corporate performance will be based upon the growth in the Company's earnings per share compared to specified targets selected by the Committee.

The following table shows the total number of performance units granted to the five most highly compensated executive officers

Named Executive	Performance Units
Steven E. Moore	47,301
Peter B. Delaney	26,961
James R. Hatfield	11,920
Jack T. Coffman	7,242
Steven R. Gerdes	5,087

Director Compensation

For 2005, compensation of non-officer directors of the Company will consist of an annual retainer fee of $66,000, of which $24,000 will be payable monthly in cash and $42,000 will be deposited in the director's account under the deferred compensation plan. These retainer amounts are unchanged from 2004. The chairman of the audit committee will receive an additional annual retainer of $10,000 (compared to $5,000 in 2004), the chairman of the compensation committee and nominating and corporate governance committees will each receive additional annual retainers of $5,000 (the same as in 2004) and the lead director will receive an additional annual retainer of $10,000 (there was no retainer for lead director in 2004). All non-officer directors will receive a fee of $1,200 for each board and committee meeting attended. This compares to a fee of $1,000 for each board and committee meeting attended in 2004.

Item 12. Security Ownership of Certain Beneficial Owners and Management.

Item 13. Certain Relationships and Related Transactions.

Under the reduced disclosure format permitted by General Instruction I(2)(c) of Form 10-K, the information otherwise required by Items 10, 11, 12 and 13 has been omitted.

Item 14. Principal Accounting Fees and Services.

The following discussion relates to the audit fees paid by Energy Corp. to its independent auditors for the services provided to Energy Corp. and its subsidiaries, including the Company.

Fees for Independent Auditors

Audit Fees

Total audit fees for 2004 were $1,937,690 for Energy Corp.'s 2004 financial statement audit. These fees include $917,850 for the audit of internal control over financial reporting pursuant to the requirements of Sarbanes-Oxley and $66,614 for services in support of debt and stock offering. Total audit fees for 2003 were $789,326, which includes $140,755 for services in support of debt and stock offerings.

The aggregate audit fees include fees billed for the audit of Energy Corp.'s annual financial statements and for the reviews of the financial statements included in Energy Corp.'s Quarterly Reports on Form 10-Q. For 2004, this amount includes estimated billings for the completion of the 2004 audit, which were rendered after year-end.

Audit-Related Fees

The aggregate fees billed for audit-related services for the fiscal year ended December 31, 2004 were $103,870, of which $61,500 was for employee benefit plan audits and $42,370 for other audit related services.

The aggregate fees billed for audit-related services for the fiscal year ended December 31, 2003 were $91,550. These fees include $56,000 for employee benefit audits and $35,550 for other audit-related services.

Tax Fees

The aggregate fees billed for tax services for the fiscal year ended December 31, 2004 were $840,995. These fees include $176,207 for tax preparation and compliance ($74,882 for the review of federal and state tax returns and $101,325 for assistance with examinations and other return issues), $418,000 for tax assistance with the Oklahoma Investment Tax Credits meals and entertainment project and Oklahoma sales use tax, $181,248 for a change in our tax accounting method and $65,540 for other tax services.

The aggregate fees billed for tax services for the fiscal year ended December 31, 2003 were $1,028,594. These fees include $174,338 for tax preparation and compliance ($53,490 for the review of federal and state tax returns and $120,848 for assistance with examinations and other return issues), $478,206 for a change in our tax accounting method, $338,742 for assistance with the Oklahoma Investment Tax Credits, and $37,308 for other tax services.

All Other Fees

These were no other fees billed to Energy Corp. in 2004 and 2003 for other services.

Audit Committee Pre-Approval Procedures

Rules adopted by the Securities and Exchange Commission in order to implement requirements of the Sarbanes-Oxley Act of 2002 require public company audit committees to pre-approve audit and non-audit services. Energy Corp.'s audit committee follows procedures pursuant to which audit, audit-related and tax services, and all permissible non-audit services, are pre-approved by category of service. The fees are budgeted, and actual fees versus the budget are monitored throughout the year. During the year, circumstances may arise when it may become necessary to engage the independent public accountants for additional services not contemplated in the original pre-approval. In those instances, we will obtain the specific pre-approval of the audit committee before engaging the independent public accountants. The procedures require the audit committee to be informed of each service, and the procedures do not include any delegation of the audit committee's responsibilities to management. The audit committee may delegate pre-approval authority to one or more of its members. The member to whom such authority is delegated will report any pre-approval decisions to the audit committee at its next scheduled meeting.

For 2004, 100% of the audit-related fees, tax fees and all other fees were pre-approved by the audit committee or the chairman of the audit committee pursuant to delegated authority.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

(a) 1. Financial Statements

The following financial statements and supplementary data are included in Part II, Item 8 of this Report:

- o Balance Sheets at December 31, 2004 and 2003
- o Statements of Capitalization at December 31, 2004 and 2003
- o Statements of Income for the years ended December 31, 2004, 2003 and 2002
- o Statements of Retained Earnings for the years ended December 31, 2004, 2003 and 2002
- o Statements of Comprehensive Income for the years ended December 31, 2004, 2003 and 2002
- o Statements of Cash Flows for the years ended December 31, 2004, 2003 and 2002
- o Notes to Financial Statements
- o Report of Independent Registered Public Accounting Firm (Audit of Financial Statements)

- o Management's Report on Internal Control Over Financial Reporting
- o Report of Independent Registered Public Accounting Firm (Audit of Internal Control)

Supplementary Data

- o Interim Financial Information

2. Financial Statement Schedule (included in Part IV)	**Page**
Schedule II - Valuation and Qualifying Accounts	124

All other schedules have been omitted since the required information is not applicable or is not material, or because the information required is included in the respective financial statements or notes thereto.

3. Exhibits

Exhibit No.	**Description**
2.01	Asset Purchase Agreement, dated as of August 18, 2003 by and between the Company and NRG McClain LLC. (Certain exhibits and schedules were omitted and registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to Energy Corp.'s Form 8-K dated August 18, 2003 (File No. 1-12579) and incorporated by reference herein)

2.02 Amendment No. 1 to Asset Purchase Agreement, dated as of October 22, 2003 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.03 to Energy Corp.'s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)

2.03 Amendment No. 2 to Asset Purchase Agreement, dated as of October 27, 2003 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.04 to Energy Corp.'s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)

2.04 Amendment No. 3 to Asset Purchase Agreement, dated as of November 25, 2003 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.05 to Energy Corp.'s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)

2.05 Amendment No. 4 to Asset Purchase Agreement, dated as of January 28, 2004 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.06 to Energy Corp.'s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)

2.06 Amendment No. 5 to Asset Purchase Agreement, dated as of February 13, 2004 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.07 to Energy Corp.'s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)

2.07 Amendment No. 6 to Asset Purchase Agreement, dated as of March 12, 2004 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.01 to Energy Corp.'s Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein)

2.08 Amendment No. 7 to Asset Purchase Agreement, dated as of April 15, 2004 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.02 to Energy Corp.'s Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein)

2.09 Amendment No. 8 to Asset Purchase Agreement, dated as of May 15, 2004 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.01 to Energy Corp.'s Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)

2.10 Amendment No. 9 to Asset Purchase Agreement, dated as of June 2, 2004 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.02 to Energy Corp.'s Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)

2.11 Amendment No. 10 to Asset Purchase Agreement, dated as of June 17, 2004 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.03 to Energy Corp.'s Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)

3.01 Copy of Restated Certificate of Incorporation. (Filed as Exhibit 4.01 to the Company's Registration Statement No. 33-59805, and incorporated by reference herein)

3.02 By-laws. (Filed as Exhibit 4.02 to Post-Effective Amendment No. Three to Registration Statement No. 2-94973 and incorporated by reference herein)

4.01 Trust Indenture dated October 1, 1995, from the Company to Boatmen's First National Bank of Oklahoma, Trustee. (Filed as Exhibit 4.29 to Registration Statement No. 33-61821 and incorporated by reference herein)

4.02 Supplemental Trust Indenture No. 1 dated October 16, 1995, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to the Company's Form 8-K dated October 23, 1995 (File No. 1-1097) and incorporated by reference herein)

4.03 Supplemental Indenture No. 2, dated as of July 1, 1997, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to the Company's Form 8-K filed on July 17, 1997 (File No. 1-1097) and incorporated by reference herein)

4.04 Supplemental Indenture No. 3, dated as of April 1, 1998, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to the Company's Form 8-K filed on April 16, 1998 (File No. 1-1097) and incorporated by reference herein)

4.05 Supplemental Indenture No. 4, dated as of October 15, 2000, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.02 to the Company's Form 8-K filed on October 20, 2000 (File No. 1-1097) and incorporated by reference herein)

4.06 Supplemental Indenture No. 5 dated as of October 24, 2001, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.06 to Registration Statement No. 333-104615 and incorporated by reference herein)

4.07 Supplemental Indenture No. 6 dated as of August 1, 2004, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.02 to the Company's Form 8-K dated August 6, 2004 (File No 1-1097) and incorporated by reference herein)

10.01 Form of Change of Control Agreement for Officers of the Company and Energy Corp. (Filed as Exhibit 10.07 to Energy Corp.'s Form 10-K for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)

10.02 Energy Corp.'s 1998 Stock Incentive Plan. (Filed as Exhibit 10.07 to Energy Corp.'s Form 10-K for the year ended December 31, 1998 (File No. 1-12579) and incorporated by reference herein)

10.03 Energy Corp.'s 2003 Stock Incentive Plan. (Filed as Annex A to Energy Corp.'s Proxy Statement for the 2003 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)

10.04 Oklahoma Gas and Electric Company Restoration of Retirement Income Plan, as amended by Amendments No. 1 and No. 2. (Filed as Exhibit 10.12 to Energy Corp.'s Form 10-K for the year ended December 31, 1996 (File No.1-12579) and incorporated by reference herein)

10.05 Amendment No. 3 to the Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.13 to Energy Corp.'s Form 10-K for the year ended December 31, 2000 (File No. 1-12579) and incorporated by reference herein)

10.06 Amendment No. 4 to the Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.14 to Energy Corp.'s Form 10-K for the year ended December 31, 2000 (File No. 1-12579) and incorporated by reference herein)

10.07 Energy Corp. Supplemental Executive Retirement Plan, as amended by Amendment No. 1. (Filed as Exhibit 10.07 to Energy Corp.'s Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

10.08 Energy Corp.'s 2003 Annual Incentive Compensation Plan. (Filed as Annex B to Energy Corp.'s Proxy Statement for the 2003 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)

10.09 Energy Corp.'s Deferred Compensation Plan and Amendment No. 1 to Energy Corp.'s Deferred Compensation Plan. (Filed as Exhibit 10.12 to Energy Corp.'s Form 10-K for the year ended December 31, 2002 (File No. 1-12579) and incorporated by reference herein)

10.10 Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to the Company's rate case. (Filed as Exhibit 99.02 to Energy Corp.'s Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12579) and incorporated by reference herein)

10.11 Amended and Restated Facility Operating Agreement for the McClain Generating Facility dated as of July 9, 2004 between the Company and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.03 to Energy Corp.'s Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)

10.12 Amended and Restated Ownership and Operation Agreement for the McClain Generating Facility dated as of July 9, 2004 between the Company and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.04 to Energy Corp.'s Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)

10.13 Operating and Maintenance Agreement for the Transmission Assets of the McClain Generating Facility dated as of August 25, 2003 between the Company and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.05 to Energy Corp.'s Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)

10.14 Credit agreement dated October 20, 2004, by and between the Company, Wachovia Bank, National Association, JPMorgan Chase Bank, Citibank, N.A., The Royal Bank of Scotland plc and Union Bank of California, N.A. (Filed as Exhibit 99.02 to Energy Corp.'s Form 8-K dated October 25, 2004 (File No. 1-12579) and incorporated by reference herein)

10.15 Amendment No. 1 to Energy Corp.'s 2003 Stock Incentive Plan. (Filed as Exhibit 10.23 to Energy Corp.'s Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

10.16 Intrastate Firm No-Notice, Load Following Transportation and Storage Services Agreement dated as of May 1, 2003 between the Company and Enogex. (Filed as Exhibit 10.24 to Energy Corp.'s Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein) [Confidential Treatment has been requested for certain portions of this exhibit.]

10.17 Amendment No. 5 to the Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.26 to Energy Corp.'s Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

10.18 Directors' Compensation. (Filed as Exhibit 10.27 to Energy Corp.'s Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

10.19 Executive Officer Compensation. (Filed as Exhibit 10.28 to Energy Corp.'s Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

10.20 Form of Non-Qualified Stock Option Agreement under Energy Corp.'s 2003 Stock Incentive Plan. (Filed as Exhibit 10.29 to Energy Corp.'s Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

10.21 Form of Performance Unit Agreement under Energy Corp.'s 2003 Stock Incentive Plan. (Filed as Exhibit 10.30 to Energy Corp.'s Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

10.22 Form of Restricted Stock Agreement under Energy Corp.'s 2003 Stock Incentive Plan. (Filed as Exhibit 10.31 to Energy Corp.'s Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

10.23 Form of Split Dollar Agreement. (Filed as Exhibit 10.32 to Energy Corp.'s Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

12.01 Calculation of Ratio of Earnings to Fixed Charges.

23.01 Consent of Ernst & Young LLP.

24.01 Power of Attorney.

31.01 Certifications Pursuant to Rule 13a-15(e)/15d-15(e) As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

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

99.01 Cautionary Statement for Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995.

<u>Executive Compensation Plans and Arrangements</u>

10.01 Form of Change of Control Agreement for Officers of the Company and Energy Corp. (Filed as Exhibit 10.07 to Energy Corp.'s Form 10-K for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)

10.02 Energy Corp.'s 1998 Stock Incentive Plan. (Filed as Exhibit 10.07 to Energy Corp.'s Form 10-K for the year ended December 31, 1998 (File No. 1-12579) and incorporated by reference herein)

10.03 Energy Corp.'s 2003 Stock Incentive Plan. (Filed as Annex A to Energy Corp.'s Proxy Statement for the 2003 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)

10.04 Oklahoma Gas and Electric Company Restoration of Retirement Income Plan, as amended by Amendments No. 1 and No. 2. (Filed as Exhibit 10.12 to Energy Corp.'s Form 10-K for the year ended December 31, 1996 (File No.1-12579) and incorporated by reference herein)

10.05 Amendment No. 3 to the Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.13 to Energy Corp.'s Form 10-K for the year ended December 31, 2000 (File No. 1-12579) and incorporated by reference herein)

10.06 Amendment No. 4 to the Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.14 to Energy Corp.'s Form 10-K for the year ended December 31, 2000 (File No. 1-12579) and incorporated by reference herein)

10.07 Energy Corp. Supplemental Executive Retirement Plan, as amended by Amendment No. 1. (Filed as Exhibit 10.07 to Energy Corp.'s Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

10.08 Energy Corp.'s 2003 Annual Incentive Compensation Plan. (Filed as Annex B to Energy Corp.'s Proxy Statement for the 2003 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)

10.09 Energy Corp.'s Deferred Compensation Plan and Amendment No. 1 to Energy Corp.'s Deferred Compensation Plan. (Filed as Exhibit 10.12 to Energy Corp.'s Form 10-K for the year ended December 31, 2002 (File No. 1-12579) and incorporated by reference herein)

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OKLAHOMA GAS AND ELECTRIC COMPANY

SCHEDULE II — Valuation and Qualifying Accounts

		Additions			
Description	**Balance at Beginning of Period**	**Charged to Costs and Expenses**	**Charged to Other Accounts**	**Deductions**	**Balance at End of Period**
			(In millions)		

Year Ended December 31, 2002										
Reserve for Uncollectible Accounts	$	6.2	$	6.5	$	---	$	8.0 (A)	$	4.7
Year Ended December 31, 2003										
Reserve for Uncollectible Accounts	$	4.7	$	2.3	$	---	$	4.4 (A)	$	2.6
Year Ended December 31, 2004										
Reserve for Uncollectible Accounts	$	2.6	$	4.8	$	---	$	4.7 (A)	$	2.7

(A) Uncollectible accounts receivable written off, net of recoveries.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Oklahoma City, and State of Oklahoma on the 25th day of February, 2005.

OKLAHOMA GAS AND ELECTRIC COMPANY
(Registrant)

By /s/ Steven E. Moore

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

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this Report has been signed below by the following persons in the capacities and on the dates indicated.

Signature	Title	Date
/ s / Steven E. Moore Steven E. Moore	Principal Executive Officer and Director;	February 25, 2005
/ s / James R. Hatfield James R. Hatfield	Principal Financial Officer; and	February 25, 2005
/ s / Donald R. Rowlett Donald R. Rowlett	Principal Accounting Officer.	February 25, 2005
Herbert H. Champlin	Director;	
Luke R. Corbett	Director;	
William E. Durrett	Director;	
Martha W. Griffin	Director;	
John D. Groendyke	Director;	
Robert Kelley	Director;	
Linda P. Lambert	Director;	
Ronald H. White, M.D.	Director; and	
J. D. Williams	Director.	

/ s / Steven E. Moore
By Steven E. Moore (attorney-in-fact) February 25, 2005

Supplemental Information to Be Furnished With Reports Filed Pursuant to Section 15(d) of the Act by Registrants Which Have Not Registered Securities Pursuant to Section 12 of the Act.

The Registrant has not sent, and does not expect to send, an annual report or proxy statement to its security holders.

Exhibit Index

Exhibit No.	Description
2.01	Asset Purchase Agreement, dated as of August 18, 2003 by and between the Company and NRG McClain LLC. (Certain exhibits and schedules were omitted and registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to Energy Corp.'s Form 8-K dated August 18, 2003 (File No. 1-12579) and incorporated by reference herein)
2.02	Amendment No. 1 to Asset Purchase Agreement, dated as of October 22, 2003 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.03 to Energy Corp.'s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.03	Amendment No. 2 to Asset Purchase Agreement, dated as of October 27, 2003 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.04 to Energy Corp.'s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.04	Amendment No. 3 to Asset Purchase Agreement, dated as of November 25, 2003 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.05 to Energy Corp.'s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.05	Amendment No. 4 to Asset Purchase Agreement, dated as of January 28, 2004 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.06 to Energy Corp.'s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.06	Amendment No. 5 to Asset Purchase Agreement, dated as of February 13, 2004 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.07 to Energy Corp.'s Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.07	Amendment No. 6 to Asset Purchase Agreement, dated as of March 12, 2004 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.01 to Energy Corp.'s Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein)
2.08	Amendment No. 7 to Asset Purchase Agreement, dated as of April 15, 2004 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.02 to Energy Corp.'s Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein)
2.09	Amendment No. 8 to Asset Purchase Agreement, dated as of May 15, 2004 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.01 to Energy Corp.'s Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
2.10	Amendment No. 9 to Asset Purchase Agreement, dated as of June 2, 2004 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.02 to Energy Corp.'s Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
2.11	Amendment No. 10 to Asset Purchase Agreement, dated as of June 17, 2004 by and between the Company and NRG McClain LLC. (Filed as Exhibit 2.03 to Energy Corp.'s Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
3.01	Copy of Restated Certificate of Incorporation. (Filed as Exhibit 4.01 to the Company's Registration Statement No. 33-59805, and incorporated by reference herein)
3.02	By-laws. (Filed as Exhibit 4.02 to Post-Effective Amendment No. Three to Registration Statement No. 2-94973 and incorporated by reference herein)

4.01 Trust Indenture dated October 1, 1995, from the Company to Boatmen's First National Bank of Oklahoma, Trustee. (Filed as Exhibit 4.29 to Registration Statement No. 33-61821 and incorporated by reference herein)

4.02 Supplemental Trust Indenture No. 1 dated October 16, 1995, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to the Company's Form 8-K dated October 23, 1995 (File No. 1-1097) and incorporated by reference herein)

4.03 Supplemental Indenture No. 2, dated as of July 1, 1997, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to the Company's Form 8-K filed on July 17, 1997 (File No. 1-1097) and incorporated by reference herein)

4.04 Supplemental Indenture No. 3, dated as of April 1, 1998, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to the Company's Form 8-K filed on April 16, 1998 (File No. 1-1097) and incorporated by reference herein)

4.05 Supplemental Indenture No. 4, dated as of October 15, 2000, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.02 to the Company's Form 8-K filed on October 20, 2000 (File No. 1-1097) and incorporated by reference herein)

4.06 Supplemental Indenture No. 5 dated as of October 24, 2001, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.06 to Registration Statement No. 333-104615 and incorporated by reference herein)

4.07 Supplemental Indenture No. 6 dated as of August 1, 2004, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.02 to the Company's Form 8-K dated August 6, 2004 (File No 1-1097) and incorporated by reference herein)

10.01 Form of Change of Control Agreement for Officers of the Company and Energy Corp. (Filed as Exhibit 10.07 to Energy Corp.'s Form 10-K for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)

10.02 Energy Corp.'s 1998 Stock Incentive Plan. (Filed as Exhibit 10.07 to Energy Corp.'s Form 10-K for the year ended December 31, 1998 (File No. 1-12579) and incorporated by reference herein)

10.03 Energy Corp.'s 2003 Stock Incentive Plan. (Filed as Annex A to Energy Corp.'s Proxy Statement for the 2003 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)

10.04 Oklahoma Gas and Electric Company Restoration of Retirement Income Plan, as amended by Amendments No. 1 and No. 2. (Filed as Exhibit 10.12 to Energy Corp.'s Form 10-K for the year ended December 31, 1996 (File No.1-12579) and incorporated by reference herein)

10.05 Amendment No. 3 to the Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.13 to Energy Corp.'s Form 10-K for the year ended December 31, 2000 (File No. 1-12579) and incorporated by reference herein)

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10.10 Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to the Company's rate case. (Filed as Exhibit 99.02 to Energy Corp.'s Form 10-Q for the quarter ended September 30, 2002 (File No. 1-12579) and incorporated by reference herein)

10.11 Amended and Restated Facility Operating Agreement for the McClain Generating Facility dated as of July 9, 2004 between the Company and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.03 to Energy Corp.'s Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)

10.12 Amended and Restated Ownership and Operation Agreement for the McClain Generating Facility dated as of July 9, 2004 between the Company and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.04 to Energy Corp.'s Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)

10.13 Operating and Maintenance Agreement for the Transmission Assets of the McClain Generating Facility dated as of August 25, 2003 between the Company and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.05 to Energy Corp.'s Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)

10.14 Credit agr eement dated October 20, 2004, by and between the Company, Wachovia Bank, National Association, JPMorgan Chase Bank, Citibank, N.A., The Royal Bank of Scotland plc and Union Bank of California, N.A. (Filed as Exhibit 99.02 to Energy Corp.'s Form 8-K dated October 25, 2004 (File No. 1-12579) and incorporated by reference herein)

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23.01 Consent of Ernst & Young LLP.

24.01 Power of Attorney.

31.01 Certifications Pursuant to Rule 13a-15(e)/15d-15(e) As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

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

99.01 Cautionary Statement for Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995.

Exhibit 12.01

Oklahoma Gas and Electric Company
SEC Method of Ratio of Earnings to Fixed Charges

	Year Ended Dec 31, 2000	Year Ended Dec 31, 2001	Year Ended Dec 31, 2002	Year Ended Dec 31, 2003	Year Ended Dec 31, 2004
Earnings:					
Pre-tax income	$ 222,734,126	$ 190,631,943	$ 197,572,191	$ 175,604,686	$ 160,634,550
Add Fixed Charges	52,948,444	49,953,948	44,577,061	42,582,265	42,234,286
Subtotal	275,682,570	240,585,891	242,149,252	218,186,951	202,868,836
Subtract:					
Allowance for funds used during construction	2,229,277	707,822	905,189	538,624	1,661,732
Total Earnings	273,453,293	239,878,069	241,244,063	217,648,327	201,207,104
Fixed Charges:					
Long-term debt interest expense	45,857,811	42,256,284	38,171,798	36,899,911	36,890,073
Other interest expense	3,151,243	4,438,997	3,044,837	2,443,702	2,246,574
Calculated interest on leased property	3,939,390	3,258,667	3,360,426	3,238,652	3,097,639
Total Fixed Charges	$ 52,948,444	$ 49,953,948	$ 44,577,061	$ 42,582,265	$ 42,234,286
Ratio of Earnings to Fixed Charges	5.16	4.80	5.41	5.11	4.76

Exhibit 23.01

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statement (Form S-3 No. 333-104615) pertaining to debt securities of Oklahoma Gas and Electric Company of our reports dated February 23, 2005, with respect to the financial statements and schedule of Oklahoma Gas and Electric Company, Oklahoma Gas and Electric Company management's assessment of the effectiveness of internal control over financial reporting and the effectiveness of internal control over financial reporting of Oklahoma Gas and Electric Company, included in this Annual Report (Form 10-K) for the year ended December 31, 2004.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 23, 2005

Exhibit 24.01

POWER OF ATTORNEY

WHEREAS, OKLAHOMA GAS AND ELECTRIC COMPANY, an Oklahoma corporation (herein referred to as the "Company"), is about to file with the Securities and Exchange Commission, under the provisions of the Securities Exchange Act of 1934, as amended, its annual report on Form 10-K for the year ended December 31, 2004; and

WHEREAS, each of the undersigned holds the office or offices in the Company herein-below set opposite his or her name, respectively;

NOW, THEREFORE, each of the undersigned hereby constitutes and appoints STEVEN E. MOORE, JAMES R. HATFIELD and DONALD R. ROWLETT and each of them individually, his or her attorney with full power to act for him or her and in his or her name, place and stead, to sign his name in the capacity or capacities set forth below to said Form 10-K and to any and all amendments thereto, and hereby ratifies and confirms all that said attorney may or shall lawfully do or cause to be done by virtue hereof.

IN WITNESS WHEREOF, the undersigned have hereunto set their hands this 19th day of January, 2005.

Steven E. Moore, Chairman, Principal Executive Officer and Director	/ s / Steven E. Moore
Herbert H. Champlin, Director	/ s / Herbert H. Champlin
Luke R. Corbett, Director	/ s / Luke R. Corbett
William E. Durrett, Director	/ s / William E. Durrett
Martha W. Griffin, Director	/ s / Martha W. Griffin
John D. Groendyke, Director	/ s / John D. Groendyke
Robert Kelley, Director	/ s / Robert Kelley
Linda P. Lambert, Director	/ s / Linda P. Lambert
Ronald H. White, M.D., Director	/ s / Ronald H. White, M.D.
J. D. Williams, Director	/ s / J. D. Williams
James R. Hatfield, Principal Financial Officer	/ s / James R. Hatfield
Donald R. Rowlett, Principal Accounting Officer	/ s / Donald R. Rowlett

STATE OF OKLAHOMA)
) SS
COUNTY OF CANADIAN)

On the date indicated above, before me, Debra Peters, Notary Public in and for said County and State, personally appeared the above named directors and officers of OKLAHOMA GAS AND ELECTRIC COMPANY, an Oklahoma corporation, and known to me to be the persons whose names are subscribed to the foregoing instrument, and they severally acknowledged to me that they executed the same as their own free act and deed.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my official seal on the 19th day of January, 2005.

/s/ Debra Peters
Debra Peters
Notary Public in and for the County
of Canadian, State of Oklahoma

My Commission Expires:
May 3, 2007

Exhibit 31.01

CERTIFICATIONS

I, Steven E. Moore, certify that:

1. I have reviewed this annual report on Form 10-K of Oklahoma Gas and Electric Company;

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

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

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

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

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting.

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 25, 2005

/s/ Steven E. Moore

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

Exhibit 31.01

CERTIFICATIONS

I, James R. Hatfield, certify that:

1. I have reviewed this annual report on Form 10-K of Oklahoma Gas and Electric Company;

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

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

4. The registrant’s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and we have:

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

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) evaluated the effectiveness of the registrant’s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant’s internal control over financial reporting that occurred during the registrant’s most recent fiscal quarter (the registrant’s fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant’s internal control over financial reporting.

5. The registrant’s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant’s auditors and the audit committee of the registrant’s board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant’s ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal control over financial reporting.

Date: February 25, 2005

/s/ James R. Hatfield

James R. Hatfield
Senior Vice President and
Chief Financial Officer

Exhibit 32.01

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

In connection with the Annual Report of Oklahoma Gas and Electric Company (the "Company") on Form 10-K for the period ended December 31, 2004, as filed with the Securities and Exchange Commission (the "Report"), each of the undersigned does hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

February 25, 2005

/s/ Steven E. Moore

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

/s/ James R. Hatfield

James R. Hatfield
Senior Vice President and
Chief Financial Officer

Exhibit 99.01

Oklahoma Gas and Electric Company Cautionary Factors

The Private Securities Litigation Reform Act of 1995 provides a "safe harbor" for forward-looking statements to encourage such disclosures without the threat of litigation providing those statements are identified as forward-looking and are accompanied by meaningful, cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Forward-looking statements have been and will be made in written documents and oral presentations of Oklahoma Gas and Electric Company (the "Company"). Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used in the Company's documents or oral presentations, the words "anticipate", "estimate", "expect", "objective" and similar expressions are intended to identify forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause the Company's actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following:

o Increased competition in the utility industry, including effects of decreasing margins as a result of competitive pressures; industry restructuring initiatives; transmission system operation and/or administration initiatives; recovery of investments made under traditional regulation; nature of competitors entering the industry; retail wheeling; a new pricing structure; and former customers entering the generation market;

o Changing market conditions and a variety of other factors associated with physical energy and financial trading activities including, but not limited to, price, basis, credit, liquidity, volatility, capacity, transmission, currency, interest rate and warranty risks;

o Risks associated with price risk management strategies intended to mitigate exposure to adverse movement in the prices of natural gas on both a global and regional basis, including commodity price changes, market supply shortages, interest rate changes and counter party default;

o Economic conditions including availability of credit, actions of rating agencies and their impact on our ability to access the capital markets, inflation rates and monetary fluctuations;

o Customer business conditions including demand for their products or services and supply of labor and materials used in creating their products and services;

o Financial or regulatory accounting principles or policies imposed by the Financial Accounting Standards Board, the Securities and Exchange Commission, the Federal Energy Regulatory Commission, state public utility commissions, the regional state committee which regulates the SPP; state entities which regulate natural gas transmission, gathering and processing and similar entities with regulatory oversight;

o Environmental laws, safety laws or other regulations passed by EPA, the ODEQ or other governing agency that may impact the cost of operations or restricts or changes the way the Company operates its facilities;

o Availability or cost of capital such as changes in: interest rates, market perceptions of the utility and energy-related industries, the Company or security ratings;

- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related damage; unscheduled generation outages, unusual maintenance or repairs; unanticipated changes to fossil fuel or gas supply costs or availability due to higher demand, shortages, transportation problems or other developments; environmental incidents; or electric transmission or gas pipeline system constraints;

- Employee workforce factors including changes in key executives;

- Rate-setting policies or procedures of regulatory entities, including environmental externalities;

- Social attitudes regarding the utility, natural gas and power industries;

- Identification of suitable investment opportunities to enhance shareowner returns and achieve long-term financial objectives through business acquisitions and divestitures;

- Some future investments made by the Company could take the form of minority interests which would limit the Company's ability to control the development or operation of an investment;

- Increased pension and healthcare costs;

- Costs and other effects of legal and administrative proceedings, settlements, investigations, claims and matters, including but not limited to those described in Note 12 of Notes to Consolidated Financial Statements of the Company's Annual Report on Form 10-K for the year ended December 31, 2004, under the caption Commitments and Contingencies;

- Technological developments, changing markets and other factors that result in competitive disadvantages and create the potential for impairment of existing assets;

- Other business or investment considerations that may be disclosed from time to time in the Company's Securities and Exchange Commission filings or in other publicly disseminated written documents.

The Company undertakes no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.