**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, 2005

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 if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ___ No _X_

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes ___ No _X_

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 a large accelerated filer, an accelerated filer or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act). (Check one): Large Accelerated Filer ___ Accelerated Filer ___ Non-Accelerated Filer _X_

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ___ No _X_

As of June 30, 2005, 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, 2006, 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, 2005

## TABLE OF CONTENTS





## 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. The Company 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 related services for 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, 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 12 of Notes to Financial Statements.

**Company Strategy**

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. As explained below, Energy Corp. intends to maintain the majority of its assets in the regulated utility business complemented by its natural gas pipeline business. The Company's long-term financial goals include earnings growth of four to five percent on a weather-normalized basis, an annual total return in the top third of its peer group, dividend growth and maintenance of strong credit ratings.

The Company has been focused on 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. As part of this plan, the Company purchased a 77 percent interest in the 520 megawatt ("MW") natural gas-fired combined cycle NRG McClain Station (the "McClain Plant") in July 2004. Capacity payment savings from reduced cogeneration payments and fuel savings from the McClain Plant will be utilized to help mitigate the price increases associated with these investments. In 2005 the Company filed a rate case to recover, among other things, its investment in, and the operating expenses of, the McClain Plant. An order was issued by the OCC on December 12, 2005 providing for a rate increase of approximately $42.3 million and the Company implemented the new electric rates in January 2006. For additional information regarding the McClain Plant acquisition, the new electric rates and related regulatory matters, see Note 12 of Notes to Financial Statements.

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, 2005, the Company and Enogex represented approximately 66 percent and 32 percent, respectively, of Energy Corp.'s consolidated assets. The remaining two 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.



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**General**

The Company furnishes retail electric service in 269 communities and their contiguous rural and suburban areas. During 2005, five other communities and four rural electric cooperatives in Oklahoma and western Arkansas purchased electricity from the Company for resale. The service area, with an estimated population of 2.0 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 88 percent of its total electric operating revenues for the year ended December 31, 2005 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 2005 was approximately 6,145 MW's on July 22, 2005. The Company's load responsibility peak demand was approximately 5,766 MW's on July 22, 2005, resulting in a capacity margin of approximately 15.8 percent. As reflected in the table below and in the operating statistics on page 3, there were approximately 26.1 million megawatt-hour ("MWH") sales in 2005 as compared to approximately 24.8 million in 2004 and 25.1 million in 2003. MWH sales to the Company's customers ("system sales") increased approximately 5.3 percent in 2005 primarily due to warmer weather during 2005. Sales to other utilities and power marketers ("off-system sales") remained flat in 2005. 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:

| | **2005** | **Increase/ (Decrease)** | 2004 | Increase/ (Decrease) | 2003 | Increase/ (Decrease) |
|---|---|---|---|---|---|---|
| System Sales (A) | 26.0 | **5.3%** | 24.7 | (0.1)% | 25.0 | 1.6% |
| Off-System Sales (A) | 0.1 | **---%** | 0.1 | ---% | 0.1 | (67.0)% |
| Total Sales | 26.1 | **5.3%** | 24.8 | (0.1)% | 25.1 | 0.8% |

(A) Sales are in millions of MWH's.

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. The Company is currently in negotiations regarding the renewal of its Oklahoma City franchise and the Company currently expects the franchise to be renewed for a 25-year term later this year.

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 12 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)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| ELECTRIC ENERGY *(Millions of MWH)* | | | |
| Generation (exclusive of station use) | **24.8** | 22.6 | 22.5 |
| Purchased | **3.3** | 4.2 | 4.5 |
| Total generated and purchased | **28.1** | 26.8 | 27.0 |
| Company use, free service and losses | **(2.0)** | (2.0) | (1.9) |
| Electric energy sold | **26.1** | 24.8 | 25.1 |
| ELECTRIC ENERGY SOLD *(Millions of MWH)* | | | |
| Residential | **8.5** | 7.9 | 8.2 |
| Commercial | **6.0** | 5.7 | 5.8 |
| Industrial | **7.2** | 7.0 | 6.8 |
| Public authorities | **2.8** | 2.7 | 2.7 |
| Sales for resale | **1.5** | 1.4 | 1.5 |
| System sales | **26.0** | 24.7 | 25.0 |

| | | | |
|---|---|---|---|
| Off-system sales | **0.1** | 0.1 | 0.1 |
| Total sales | **26.1** | 24.8 | 25.1 |
| | | | |
| ELECTRIC OPERATING REVENUES *(In millions)* | | | |
| Residential | **$ 663.6** | $ 611.4 | $ 601.4 |
| Commercial | **418.9** | 389.9 | 372.5 |
| Industrial | **355.6** | 326.7 | 293.4 |
| Public authorities | **173.1** | 158.5 | 146.1 |
| Sales for resale | **67.7** | 57.0 | 57.7 |
| Provision for refund on gas transportation and storage case | **(2.0)** | (6.9) | --- |
| System sales revenues | **1,676.9** | 1,536.6 | 1,471.1 |
| Off-system sales revenues | **4.9** | 0.8 | 4.1 |
| Other | **38.9** | 40.7 | 41.9 |
| Total Electric Operating Revenues | **$ 1,720.7** | $ 1,578.1 | $ 1,517.1 |
| | | | |
| ACTUAL NUMBER OF ELECTRIC CUSTOMERS *(At end of period)* | | | |
| Residential | **639,733** | 630,736 | 622,527 |
| Commercial | **81,728** | 80,786 | 80,265 |
| Industrial | **9,472** | 9,420 | 8,970 |
| Public authorities | **14,515** | 14,022 | 13,658 |
| Sales for resale | **45** | 44 | 50 |
| Total | **745,493** | 735,008 | 725,470 |
| | | | |
| AVERAGE RESIDENTIAL CUSTOMER SALES | | | |
| Average annual revenue | **$ 1,043.60** | $ 975.08 | $ 970.04 |
| Average annual use (kilowatt-hour (“KWH”)) | **13,445** | 12,630 | 13,202 |
| Average price per KWH (cents) | **$ 7.76** | $ 7.72 | $ 7.35 |



**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, 2005 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 Company assets or income for affiliate transactions. In addition, the Energy Policy Act of 2005 enacted the Public Utility Holding Company Act of 2005, which in turn granted to the FERC access to the books and records of Energy Corp. and its affiliates as the FERC deems relevant to costs incurred by the Company or necessary or appropriate for the protection of utility customers with respect to jurisdictional rates.

***Regulatory Matters***

**Gas Transportation and Storage Agreement**

As part of the settlement of a Company rate case in November 2002 (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. Because the required integrated service was not available in the marketplace from parties other than Enogex, 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 lost and unaccounted for gas on the transportation system. To the extent the Company transports gas in quantities in excess of the prescribed MDQ’s or MHQ’s, it pays an overrun service charge. During the years ended December 31, 2005, 2004 and 2003, the Company paid Enogex approximately $47.6 million, $49.6 million and $44.7 million, respectively, for gas transportation and storage services.

On July 14, 2005, the OCC issued an order in this case approving a $41.9 million annual recovery. The OCC order disallowed the recovery by the Company of the amount that Enogex charges the Company for the cost of fuel used, or otherwise unaccounted for, in providing natural gas transportation and storage service to the Company. Over the last three years, this amount has ranged from $1.2 million to $3.7 million annually. This amount was approximately $1.2 million in 2005 and is projected to be approximately $0.5 million in 2006. The OCC's order required the Company to refund to its Oklahoma customers the difference between the amounts collected from such customers in the past based on an annual rate of $46.8 million for gas transportation and storage services and the $41.9 million annual rate authorized by the OCC's order. Based on the order, the Company's refund obligation was approximately $8.8 million. The Company began refunding this obligation in September 2005 through its automatic fuel adjustment clause. The balance of the refund obligation was approximately $6.0 million at December 31, 2005. For further information, see Note 12 of Notes to Financial Statements.

In connection with the Enogex gas transportation and storage agreement, the Company has also recorded a refund obligation in Arkansas. The Company expects to meet with the APSC in early 2006 to determine the amount of the refund. The Company estimated its refund obligation to be approximately $1.1 million at December 31, 2005 to Arkansas customers assuming the Arkansas refund obligation is calculated consistent with the Oklahoma calculation.



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**Oklahoma Rate Case Filing**

On May 20, 2005, the Company filed with the OCC an application for an annual rate increase of approximately $89.1 million to recover, among other things, its investment in, and the operating expenses of, the McClain Plant. As a result of the McClain Plant acquisition completed on July 9, 2004, and consistent with the Settlement Agreement with the OCC, the Company had 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. The Company's rate case application included an estimate of $25.9 million related to the McClain Plant regulatory asset. At December 31, 2005, the actual incurred expenses included in the McClain Plant regulatory asset were approximately $24.9 million. Such costs will be recovered over a four-year time period as authorized in the OCC rate order beginning in January 2006. The OCC also authorized approximately $15.5 million of the $24.9 million regulatory asset to be included in the Company's rate base for purposes of earning a return. The application also included, among other things, implementation of enhanced reliability programs in the Company's system, increased fuel oil inventory, the establishment of a separate recovery mechanism for major storm expense, the establishment of new rate classes for public schools and related facilities, the establishment of a military base rider, the establishment of a new low income assistance tariff and the proposal to make the guaranteed flat bill pilot tariff permanent for residential and small business customers.

On September 12, 2005, 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 a rate increase of approximately $13.0 million, one-seventh the amount requested by the Company in its May 20, 2005 application. The recommendations in the testimony of the Attorney General's office and the Oklahoma Industrial Energy Consumers recommended a rate decrease of approximately $24 million and $31 million, respectively. Hearings in the rate case began on October 10, 2005 and concluded on October 24, 2005. On November 3, 2005, the Referee appointed by the OCC for this proceeding issued a report recommending an estimated rate increase of approximately $42 million for the Company. On December 12, 2005, the OCC issued an order providing for a $42.3 million increase in rates and a 10.75 percent return on equity, based on a capital structure consisting of 55.7 percent equity and 44.3 percent debt. The new rates became effective in January 2006. Also included in the order, among other things, are new depreciation rates effective January 2006 and a provision which modified the Company's mechanism for the recovery of over or under recovered fuel costs from its customers to allow interest to be applied to the over or under recovery. See "Rate Activities and Proposals" for a discussion of other items included in the OCC order.

**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 regional state committee, which is comprised of commissioners of the applicable state regulatory commissions, finished its process of formulating a methodology for funding transmission expansion in the SPP control area by allocating costs of transmission expansion to the SPP members who benefit. The SPP Board of Directors adopted this plan and filed it with the FERC on February 28, 2005, Docket No. ER05-652. The FERC conditionally accepted the plan on April 21, 2005 with an effective date of May 5, 2005. The SPP made a second compliance filing on October 20, 2005 on various minor issues associated with the plan. On January 11, 2006, the FERC conditionally accepted the compliance filing, but required the SPP to make minor wording changes within 30 days. The SPP filed these minor wording changes on February 10, 2006.

Also, the SPP filed on June 15, 2005, Docket No. ER05-1118, to create a real-time, offer-based imbalance energy market which will require cash settlements for over or under generation. Market participants, including the Company, will be required to submit resource plans and can submit offer curves for each resource available for dispatch. In addition, the filing contains provisions allowing the SPP to order certain dispatching of generating units and a market monitoring plan which provides a clear set of rules, the potential consequences if the rules are violated and the areas in which an independent market monitor will examine and report. The scheduled implementation date of the imbalance energy market is May 1, 2006. See Note 12 of Notes to Financial Statements for a further discussion.



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***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.

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, 2005 and 2004, the Company had regulatory assets of approximately $189.2 million and $137.3 million, respectively, and regulatory liabilities of approximately $118.1 million and $122.2 million, respectively.

As discussed in Note 12 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. 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. 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 12 of Notes to Financial Statements for a discussion of certain regulatory matters including the gas transportation and storage contract between the Company and Enogex, the Company's 2005 rate case order, security enhancements, national energy legislation and state legislative initiatives.

**Rate Activities and Proposals**

Since 2002, the Company has had several different customer programs and rate options. 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 may benefit from the GFB option. The GFB option received OCC approval for permanent rate status in the Company's recently concluded rate case. A second tariff rate option provides a "renewable energy" resource to the 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 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. Another program being offered to the Company's commercial and industrial customers is a 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 rate options coupled with the Company's other 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 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 2004 or 2005 associated with these rate options, but minimal revenue variations may occur in the future based upon changes in customers' usage characteristics if they choose these programs. In 2005, the GFB pilot customers continued to renew at the 2004 renewal rate of over 90 percent.

As part of the rate order issued by the OCC in December 2005, the Company received OCC approval for the creation of two new rate classes, Public Schools-Demand and Public Schools Non-Demand. These two classes of service will provide the Company flexibility to provide targeted programs for load management to public schools and their unique usage patterns. Another item approved in the order was the creation of service level fuel differentiation which allows customers to pay fuel costs that better reflect energy losses on a service level basis. The OCC order also approved a military base rider which demonstrates Oklahoma's continued commitment to our military partners. The Company's highly successful wind program was authorized to lower its cost on a per kwh basis, which provides subscribing customers the increased incentive to hedge against future natural gas prices. The order also enables the Company's low-income qualified customers to receive relief on their summer electric bills by waiving the customer charge on their monthly bills from June to September of each year. Also included in the Company's rate case application, but not approved, was the establishment of a separate recovery mechanism for major storm expense.

**Fuel Supply**

During 2005, approximately 70 percent of the Company-generated energy was produced by coal-fired units and 30 percent by natural gas-fired units. Of the Company's 6,122 total MW capability reflected in the table under Item 2. Properties, approximately 3,553 MW's, or 58 percent, are from natural gas generation and approximately 2,569 MW's, or 42 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:

| | **2005** | 2004 | 2003 | 2002 | 2001 |
|---|---|---|---|---|---|
| Coal | **$ 0.98** | $ 1.00 | $ 0.93 | $ 0.93 | $ 0.81 |
| Natural Gas | **$ 8.76** | $ 6.57 | $ 6.46 | $ 3.78 | $ 4.91 |
| Weighted Average | **$ 3.21** | $ 2.69 | $ 2.27 | $ 1.77 | $ 1.97 |

The increase in the weighted average cost of fuel in 2005 and in 2004 was primarily due to increased natural gas prices and increased amounts of natural gas being burned. 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 recoverable through the Company's regulatorily approved automatic fuel adjustment clauses. See Note 1 of Notes to Financial Statements.

***Coal***

All of the Company's coal-fired units, with an aggregate capability of approximately 2,569 MW's, are designed to burn low sulfur western coal. The Company purchases coal primarily under long-term contracts expiring in years 2010 and 2011. During 2005, the Company purchased approximately 9.2 million tons of coal from the following Wyoming suppliers: Kennecott Energy Company, Arch Coal Inc./Triton Coal Company, Peabody Coal Sales Company and Foundation Coal West, Inc. The combination of all coal has a weighted average sulfur content of less than 0.23 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



0.49 lbs. of sulfur dioxide per MMBtu, well within the limitations of the provisions of the Federal Clean Air Act discussed in Note 12 of Notes to Financial Statements.

The Company has continued its efforts to maximize the utilization of its coal-fired units at its Sooner and Muskogee generating plants. See "Environmental Laws and Regulations" in Note 11 of Notes to Financial Statements for a discussion of environmental matters affecting the Company.

*Coal Shipment Disruption*

In July 2005, the Company received notification from Union Pacific Railroad ("Union Pacific") that, in May 2005, Union Pacific and BNSF Railway ("BNSF") experienced successive derailments on the jointly-owned rail line serving the Southern Powder River Basin coal producers. According to Union Pacific, these two derailments were caused by track that had become unstable from an accumulation of coal dust in the roadbed combined with unusually heavy rainfall. BNSF, which maintains and operates the line, concluded that a significant part of the line needed to be repaired before normal train operations could resume. While the repairs were taking place, Union Pacific was unable to operate at full capacity from the Powder River Basin. In November 2005, Union Pacific notified the Company that the South Powder River Basin joint line force majeure condition that was declared in May 2005 had ended. On December 2, 2005, BNSF completed the enhanced joint line maintenance program which opened the way for a return to normal operating conditions. It is expected that as rail traffic improves, the Company will be able to increase its level of coal inventories. At December 31, 2005, the Company had slightly more than 20 days of coal supply for each of its coal-fired units at its Sooner and Muskogee generating plants.

*Natural Gas*

The Company utilized a request for bid ("RFB") to acquire approximately 30 percent of its projected annual natural gas requirements for 2006. 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 2006 will be secured through a new RFB issued in the first quarter of 2006. 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. At December 31, 2005, the Company had approximately 2.7 million MMBtu's in natural gas storage that it acquired for approximately $10.5 million.

*Wind*

During 2003, the Company contracted with FPL Energy for 50 MW's 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 subscribed for all or part of their electricity usage. As of January 31, 2006, the Company's current wind program is fully subscribed. 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.

On December 22, 2005, Energy Corp. issued a press release announcing that the Company had entered into a non-binding letter of intent to purchase a 120 MW wind farm planned for construction in northwestern Oklahoma. Invenergy Wind Development Oklahoma LLC ("Invenergy LLC") would develop the new wind power-generation facility to be owned and operated by the Company. The wind farm, north of Woodward in Harper County, is expected to cost approximately $195 million, including the cost of transmission interconnection facilities. A definitive Agreement To Engineer, Procure and Construct Wind Generation Energy System ("EPC Contract") was reached on February 20, 2006, subject to various conditions. Those conditions include agreement by the parties as to certain exhibits to the EPC Contract, approval of the EPC Contract by the Company's Board of Directors and approval of the EPC Contract by the Manager of Invenergy LLC, all of which have to be completed on or before March 13, 2006. In addition, 90 days subsequent to the occurrence of these events, the Company or Invenergy LLC have the unilateral right to terminate the EPC Contract if certain additional events have not occurred, including the following: (i) OCC approval of the terms of the EPC Contract and of a recovery rider providing the Company the



opportunity to recover all costs associated with the wind facility, including transmission interconnection and transmission upgrade costs; (ii) completion by the SPP of all necessary transmission studies; (iii) Invenergy LLC's acquisition of certain land agreements; (iv) Invenergy LLC's execution of a contract acceptable to the Company with a balance of work contractor; and (v) Invenergy LLC's acquisition of certain permits. If all of these conditions are met, the new wind farm is expected to be constructed and producing power on or before December 31, 2006. OCC hearings are expected to occur in April 2006. See Note 12 of Notes to Financial Statements for a further discussion.

**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 2006 to 2008 construction program includes continued investment in its distribution, generation and transmission system. The Company plans to continue to invest in its electric system at a level consistent with 2005. These capital expenditures do not include any capital requirements associated with the Company's proposed wind power project pending approval from the OCC. The Company has approximately 430 MW's of contracts with qualified cogeneration facilities ("QF") and small power production producers' ("QF contracts") that will expire at the end of 2007, unless extended by the Company. For one of these QF contracts, the Company purchases 100 percent of electricity generated by the QF. For the other QF contract, the Company can purchase up to 17 percent of electricity generated by the QF. In addition, effective September 1, 2004, the Company entered into a new 15-year power purchase agreement for 120 MW's with PowerSmith Cogeneration Project, L.P. ("PowerSmith"), in which the Company purchases 100 percent of electricity generated by 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 as well as wind generation facilities. 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 2005 and 2004, Energy Corp. made contributions of approximately $32.0 million and $69.0 million, respectively, to ensure that the pension plan maintains an adequate funded status, of which approximately $24.8 million and $54.5 million, respectively, were allocated to the Company. During 2006, Energy Corp. may contribute up to $90.0 million to the pension plan, of which up to $69.9 million may 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 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 cash needs. Energy Corp. utilizes short-term borrowings (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 generally are used to meet working capital requirements. See Note 9 of Notes to Financial Statements for a table showing Energy Corp.'s and the Company's lines of credit in place, commercial paper and available cash at December 31, 2005. At December 31, 2005, Energy Corp.'s short-term borrowings consisted of commercial paper.

**ENVIRONMENTAL MATTERS**

Approximately $3.6 million of the Company's capital expenditures budgeted for 2006 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 $55.3 million during 2006 as compared to approximately $61.7 million in 2005. 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 11 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 2,025 employees at December 31, 2005.

## 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 ("SEC").

## Item 1A. Risk Factors.

**In addition to the other information in this 10-K and other documents filed by us with the SEC from time to time, the following factors should be carefully considered in evaluating the Company. Such factors could affect actual results and cause results to differ materially from those expressed in any forward-looking statements made by or on our behalf. Additional risks and uncertainties not currently known to us or that we currently view as immaterial may also impair our business operations.**

## REGULATORY RISKS

***Our profitability depends to a large extent on our ability to fully recover our costs from our customers and there may be changes in the regulatory environment that impair our ability to recover costs from our customers.***

We are subject to comprehensive regulation by several federal and state utility regulatory agencies, which significantly influences our operating environment and our ability to fully recover our costs from utility customers. With rising fuel costs, recoverability of under recovered amounts from our customers is a significant risk. The utility commissions in the states where we operate regulate many aspects of our utility operations including siting and construction of facilities, customer service and the rates that we can charge customers. The profitability of our operations is dependent on our ability to fully recover costs related to providing energy and utility services to our customers. On May 20, 2005, we filed for an $89 million annual rate increase to recover investments in our electric system, including those related to our McClain Plant. Several parties made filings recommending a significantly lower increase and, in certain cases, rate decreases. On December 12, 2005, the OCC issued an order providing for a



$42.3 million rate increase in our electric rates which became effective in January 2006. This rate order will require us to reduce planned electric system upgrades and expansion projects, and we are considering when to return to the OCC to seek further rate relief. We cannot assure you that the OCC will grant us rate increases in the future or in the amounts we request, and it could instead lower our rates.

In recent years, the regulatory environments in which we operate have received an increased amount of public attention. It is possible that there could be changes in the regulatory environment that would impair our ability to fully recover costs historically absorbed by our customers. State utility commissions generally possess broad powers to ensure that the needs of the utility customers are being met.

We are unable to predict the impact on our operating results from the future regulatory activities of any of the agencies that regulate us. Changes in regulations or the imposition of additional regulations could have an adverse impact on our results of operations.

***Our rates are subject to regulation by the states of Oklahoma and Arkansas, as well as by a federal agency, whose regulatory paradigms and goals may not be consistent.***

We are currently a vertically integrated electric utility and most of our revenue results from the sale of electricity to retail customers subject to bundled rates that are approved by the applicable state utility commission and the sale of electricity to wholesale customers subject to rates and other matters approved by the FERC.

We operate in Oklahoma and western Arkansas and are subject to regulation by the OCC and the APSC, in addition to the FERC. Exposure to inconsistent state and federal regulatory standards may limit our ability to operate profitably. Further alteration of the regulatory landscape in which we operate may harm our financial condition and results of operations.

***Costs of compliance with environmental laws and regulations are significant and the cost of compliance with future environmental laws and regulations may adversely affect our results of operations, financial position, or liquidity.***

We are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, wildlife mortality, natural resources and health and safety that could, among other things, restrict or limit the output of certain facilities or the use of certain fuels required for the production of electricity and/or require additional pollution control equipment and otherwise increase costs. There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations and those costs may be even more significant in the future.

***Our results of operations could be affected by our ability to renegotiate franchise agreements with municipalities and counties in Oklahoma.***

We have several franchise agreements with municipalities and counties in Oklahoma and our ability to renegotiate these agreements may affect our results of operations and financial position.

***The regional power market in which we operate has changing transmission regulatory structures, which may affect the transmission assets and related revenues and expenses.***

We currently own and operate transmission facilities as part of a vertically integrated utility. We are a member of the SPP regional transmission organization ("RTO") and have transferred operational authority (but not ownership) of our transmission facilities to the SPP RTO. The SPP RTO is planning to develop and operate a regional market for trading in electric energy. Because it remains unclear how and when the SPP RTO will implement the market or what new market rules it will establish, we are unable to assess fully the impact that these developments may have on our business. Our revenues, expenses, assets and liabilities may be adversely affected by changes in the organization, operation and regulation by the FERC or the SPP RTO.



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***Our Settlement Agreement with the OCC relating to our 2002 rate case targets $75 million of savings over a three-year period from the acquisition of new generation. We may not be able to achieve such targeted savings, in which case, we will be required to credit any unrealized savings to our Oklahoma customers.***

As part of our settlement agreement in November 2002, we indicated that the acquisition of up to 400 MW's of new generation through the purchase of a 77 percent in the McClain Plant should provide $75 million of savings to our customers over three years. We also agreed that if we are unable to demonstrate such savings, we will credit our customers any unrealized savings below $75 million. We cannot assure you that we will be able to realize the targeted $75 million of savings to our customers, in which case, we will be required to credit unrealized savings to our Oklahoma customers.

***Increased competition resulting from restructuring efforts could have a significant financial impact on us and consequently decrease our revenue.***

We have been and will continue to be affected by competitive changes to the utility and energy industries. Significant changes already have occurred and additional changes have been proposed to the wholesale electric market. Although retail restructuring efforts in Oklahoma and Arkansas have been postponed for the time being, if such efforts were renewed, retail competition and the unbundling of regulated energy service could have a significant financial impact on us due to an impairment of assets, a loss of retail customers, lower profit margins and/or increased costs of capital. Any such restructuring could have a significant impact on our financial position, results of operations and cash flows. We cannot predict when we will be subject to changes in legislation or regulation, nor can we predict the impact of these changes on our financial position, results of operations or cash flows. We believe that the prices for electricity and the quality and reliability of our service currently place us in a position to compete effectively in the energy market.

***Recent events that are beyond our control have increased the level of public and regulatory scrutiny of our industry. Governmental and market reactions to these events may have negative impacts on our business, financial condition and access to capital.***

As a result of the energy crisis in California during the summer of 2001, the volatility of natural gas prices in North America, the bankruptcy filing by Enron Corporation, accounting irregularities at public companies in general, and energy companies in particular, and investigations by governmental authorities into energy trading activities, companies in the regulated and unregulated utility business have been under an increased amount of public and regulatory scrutiny and suspicion. The accounting irregularities have caused regulators and legislators to review current accounting practices, financial disclosures and relationships between corporations and their independent auditors. The capital markets and rating agencies also have increased their level of scrutiny. We believe that we are complying with all applicable laws and accounting standards, but it is difficult or impossible to predict or control what effect these types of events may have on our business, financial condition or access to the capital markets.

As a result of these events, Congress passed the Sarbanes-Oxley Act of 2002. It is unclear what additional laws or regulations may develop, and we cannot predict the ultimate impact of any future changes in accounting regulations or practices in general with respect to public companies, the energy industry or our operations specifically. Any new accounting standards could affect the way we are required to record revenues, expenses, assets and liabilities. These changes in accounting standards could lead to negative impacts on reported earnings or increases in liabilities that could, in turn, affect our reported results of operations.

***We are subject to substantial utility and energy regulation by governmental agencies. Compliance with current and future utility and energy regulatory requirements and procurement of necessary approvals, permits and certifications may result in significant costs to us.***

We are subject to substantial regulation from federal, state and local regulatory agencies. We are required to comply with numerous laws and regulations and to obtain numerous permits, approvals and certificates from the governmental agencies that regulate various aspects of our businesses, including customer rates, service regulations, retail service territories, sales of securities, asset acquisitions and sales, accounting policies and practices and the operation of generating facilities. We believe the necessary permits, approvals and certificates have been obtained



for our existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from future regulatory activities of these agencies.

**OPERATIONS RISKS**

***Our results of operations may be impacted by disruptions beyond our control.***

We are exposed to risks related to performance of contractual obligations by our suppliers. We are dependent on coal for much of our electric generating capacity. We rely on suppliers to deliver coal in accordance with short and long-term contracts. We have certain coal supply contracts in place; however, there can be no assurance that the counterparties to these agreements will fulfill their obligations to supply coal to us. The suppliers under these agreements may experience financial or technical problems which inhibit their ability to fulfill their obligations to us. In addition, the suppliers under these agreements may not be required to supply coal to us under certain circumstances, such as in the event of a natural disaster. Coal delivery may be subject to short-term interruptions or reductions due to various factors, including transportation problems, weather and availability of equipment. Failure or delay by our suppliers of coal deliveries could disrupt our ability to deliver electricity and require us to incur additional expenses to meet the needs of our customers. In addition, as agreements with our suppliers expire, we may not be able to enter into new agreements for coal delivery on equivalent terms.

Also, because our generation and transmission systems are part of an interconnected regional grid, we face the risk of possible loss of business due to a disruption or black-out caused by an event (severe storm, generator or transmission facility outage) on a neighboring system or the actions of a neighboring utility, similar to the August 14, 2003 black-out in portions of the eastern U.S. and Canada. Any such disruption could result in a significant decrease in revenues and significant additional costs to repair assets, which could have a material adverse impact on our financial condition and results of operations.

***Weather conditions such as tornadoes, thunderstorms, ice storms, wind storms, as well as seasonal temperature variations may adversely affect our results of operations and financial position.***

Weather conditions directly influence the demand for electric power. In the Company’s service area, demand for power peaks during the hot summer months, with market prices also typically peaking at that time. As a result, overall operating results may fluctuate on a seasonal and quarterly basis. In addition, we have historically sold less power, and consequently received less revenue, when weather conditions are milder. Unusually mild weather in the future could reduce our revenues, net income, available cash and borrowing ability. Severe weather, such as tornadoes, thunderstorms, ice storms and wind storms, may cause outages and property damage which may require us to incur additional costs that are generally not insured and that may not be recoverable from customers. The effect of the failure of our facilities to operate as planned, as described above, would be particularly burdensome during a peak demand period.

**FINANCIAL AND MARKET RISKS**

***Increasing costs associated with our defined benefit retirement plans, health care plans and other employee-related benefits may adversely affect our results of operations, financial position, or liquidity.***

We have defined benefit and postretirement plans that cover substantially all of our employees. Assumptions related to future costs, returns on investments, interest rates and other actuarial assumptions have a significant impact on our earnings and funding requirements. Based on our assumptions at December 31, 2005 and assuming continuation of the current federal interest rate relief beyond 2005, in order to maintain minimum funding levels for our pension plans, we expect to continue to make future contributions to maintain required funding levels. It is our practice to also make voluntary contributions to maintain more prudent funding levels than minimally required. These amounts are estimates and may change based on actual stock market performance, changes in interest rates and any changes in governmental regulations.

In addition to the costs of our retirement plans, the costs of providing health care benefits to our employees and retirees have increased substantially in recent years. We believe that our employee benefit costs, including costs related to health care plans for our employees and former employees, will continue to rise. The increasing costs and



funding requirements with our defined benefit retirement plan, health care plans and other employee benefits may adversely affect our results of operations, financial position, or liquidity.

***We may be able to incur substantially more indebtedness, which may increase the risks created by our indebtedness.***

The terms of the indentures governing our debt securities do not fully prohibit us from incurring additional indebtedness. If we are in compliance with the financial covenants set forth in our revolving credit agreements and the indentures governing our debt securities, we may be able to incur substantial additional indebtedness. If we incur additional indebtedness, the related risks that we now face may intensify.

***Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships.***

We cannot assure you that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Any future downgrade could increase the cost of short-term borrowings but would not result in any defaults or accelerations as a result of the rating changes.

***We are subject to commodity price risk.***

We are exposed to commodity price risk in our generation and retail distribution operations. To minimize the risk of commodity prices, we may enter into physical or financial derivative instrument contracts to hedge purchase and sale commitments, fuel requirements and inventories of natural gas, distillate fuel oil, electricity, coal and emission allowances. However, financial derivative instrument contracts do not eliminate the risk. Specifically, such risks include commodity price changes, market supply shortages and interest rate changes. The impact of these variables could result in our inability to fulfill contractual obligations, significantly higher energy or fuel costs relative to corresponding sales contracts or increased interest expense. However, exposure to commodity price risk related to our retail customers is partially mitigated by our fuel adjustment clause, although we cannot assure you that all increases in our commodity prices, including fuel costs, will be completely recovered, or that any such recovery will be timely.

***We are subject to credit risk.***

We are exposed to credit risks in our generation and retail distribution operations. Credit risk includes the risk that counterparties that owe us money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected, and we could incur losses.

**Item 1B. Unresolved Staff Comments.**

None.



**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 6,122 MW's. 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 | 2005 Capacity Factor (A) | Unit Capability (MW) | Station Capability (MW) |
|---|---|---|---|---|---|---|---|---|
| Seminole | 1 | 1971 | Steam-Turbine | Gas | Base Load | 20.1% | 506.0 | |
| | 1GT | 1971 | Combustion-Turbine | Gas | Peaking | 0.0%(B) | 16.0 | |
| | 2 | 1973 | Steam-Turbine | Gas | Base Load | 21.5% | 500.5 | |
| | 3 | 1975 | Steam-Turbine | Gas/Oil | Base Load | 27.2% | 519.0 | 1,541.5 |
| Muskogee | 3 | 1956 | Steam-Turbine | Gas | Base Load | 6.0% | 166.0 | |
| | 4 | 1977 | Steam-Turbine | Coal | Base Load | 70.8% | 510.5 | |
| | 5 | 1978 | Steam-Turbine | Coal | Base Load | 70.1% | 521.6 | |
| | 6 | 1984 | Steam-Turbine | Coal | Base Load | 83.1% | 515.0 | 1,713.1 |
| Sooner | 1 | 1979 | Steam-Turbine | Coal | Base Load | 87.3% | 510.0 | |
| | 2 | 1980 | Steam-Turbine | Coal | Base Load | 73.1% | 512.0 | 1,022.0 |
| Horseshoe | 6 | 1958 | Steam-Turbine | Gas/Oil | Base Load | 12.6% | 168.5 | |
| Lake | 7 | 1963 | Combined Cycle | Gas/Oil | Base Load | 13.4% | 234.0 | |
| | 8 | 1969 | Steam-Turbine | Gas | Base Load | 6.7% | 387.0 | |
| | 9 | 2000 | Combustion-Turbine | Gas | Peaking | 7.2%(B) | 45.5 | |
| | 10 | 2000 | Combustion-Turbine | Gas | Peaking | 7.4%(B) | 45.5 | 880.5 |
| Mustang | 1 | 1950 | Steam-Turbine | Gas | Peaking | 0.6%(B) | 53.0 | |
| | 2 | 1951 | Steam-Turbine | Gas | Peaking | 0.2%(B) | 53.0 | |
| | 3 | 1955 | Steam-Turbine | Gas | Base Load | 9.3% | 117.5 | |
| | 4 | 1959 | Steam-Turbine | Gas | Base Load | 13.4% | 250.0 | |
| | 5A | 1971 | Combustion-Turbine | Gas/Jet Fuel | Peaking | 2.1%(B) | 31.0 | |
| | 5B | 1971 | Combustion-Turbine | Gas/Jet Fuel | Peaking | 1.9%(B) | 33.0 | 537.5 |
| Conoco | 1 | 1991 | Combustion-Turbine | Gas | Base Load | 37.4% | 31.5 | |
| | 2 | 1991 | Combustion-Turbine | Gas | Base Load | 40.4% | 28.3 | 59.8 |
| 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 | 0.2%(B) | 12.0 | 12.0 |
| McClain (D) | 1 | 2001 | Combined Cycle | Gas | Base Load | 75.9% | 355.5 | 355.5 |
| Total Generating Capability (all stations) | | | | | | | | 6,121.9 |

(A) 2005 Capacity Factor = 2005 Net Actual Generation / (2005 Net Maximum Capacity (Nameplate Rating in MW's) x Period Hours (8,760 Hours)).

(B) Peaking units, which are used when additional capacity is required, are also necessary to meet the SPP 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, 2005, the Company's transmission system included: (i) 28 substations with a total capacity of approximately 7.7 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 1.9 million kVA and approximately 252 structure miles of lines in Arkansas. The Company's distribution system included: (i) 334 substations with a total capacity of approximately 10.0 million kVA, 22,653 structure miles of overhead lines, 2,054 miles of underground conduit and 8,299 miles of underground conductors in Oklahoma; and (ii) 37 substations with a total capacity of



approximately 1.6 million kVA, 1,896 structure miles of overhead lines, 257 miles of underground conduit and 478 miles of underground conductors in Arkansas.

During the three years ended December 31, 2005, the Company's gross property, plant and equipment additions were approximately $756.9 million and gross retirements were approximately $122.5 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 15.7 percent of total property, plant and equipment at December 31, 2005.

**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 legal 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 11 and 12 of Notes to Financial Statements, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these 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 sought 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. No action has been taken in this case for more than eight years and, for this reason, the Company is treating this case as closed.

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 was held March 17 - 18, 2005. A ruling in this case by the special master was received in May 2005 which dismissed the Company and all Enogex parties named in these proceedings. This ruling has been appealed to the District Court of Wyoming. An oral argument on this appeal to the District Court was made on December 9, 2005 but there is no ruling in this case to date. The Company intends to vigorously defend this action. At this time, 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.

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 was held April 1, 2005. Energy Corp. intends to vigorously defend this action. At this time, 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.

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 13 years. Plaintiff alleged 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 sought $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 was permitted to amend its petition to include a claim based on theories of tort. Specifically, Plaintiff alleged that the Company engaged in tortious conduct by, among other things, falsifying documents, sponsoring false testimony and putting forward legal defenses, which were known by the Company to be without merit. If successful, Plaintiff believed that these theories could give Plaintiff a basis to seek punitive damages. This lawsuit was stayed from June 2002 through February 2005 during the appeal of a similar case filed by Kaiser-Francis in Grady County, Oklahoma.

On January 3, 2006, the trial court granted the Company's motion for partial summary judgment on Plaintiff's tort claim. This ruling struck from the lawsuit Plaintiff's claim of (i) approximately $4.7 million in tort damages; and (ii) approximately $11 million in punitive damages. On January 13, 2006, at a court-ordered settlement conference, a settlement was reached in the Blaine County case whereby the Company agreed to pay $8.9



million to Kaiser-Francis. The suit was dismissed with prejudice on January 18, 2006 and this case is now closed. The Company believes that the settlement amount is recoverable through its regulated electric rates.

In the similar case in Grady County, Oklahoma, Kaiser-Francis alleged that the Company breached the terms of several gas purchase contracts in amounts set forth in the contracts. As previously reported in the Company's Form 10-Q for the quarter ended September 30, 2005, the case was settled and is now closed.

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 contended 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 sought attorney fees. The Company obtained a partial summary judgment against Terra Tech for approximately $0.2 million, and is pursuing collection on this amount. This case is now closed.

**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 24, 2006:

| Name | Age | Title |
|---|---|---|
| Steven E. Moore | 59 | Chairman of the Board, President and Chief Executive Officer |
| Peter B. Delaney | 52 | Executive Vice President and Chief Operating Officer |
| James R. Hatfield | 48 | Senior Vice President and Chief Financial Officer |
| Carla D. Brockman | 46 | Vice President - Administration / Corporate Secretary |
| Steven R. Gerdes | 49 | Vice President - Utility Operations |
| Gary D. Huneryager | 55 | Vice President - Internal Audits |
| Melvin H. Perkins, Jr. | 57 | Vice President - Transmission |
| Paul L. Renfrow | 49 | Vice President - Public Affairs |
| Reid Nuttall | 48 | Vice President - Enterprise Information and Performance |
| Scott Forbes | 48 | Controller and Chief Accounting Officer |
| Donald R. Rowlett | 48 | Chief Accounting Policy Officer |
| Deborah S. Fleming | 50 | Treasurer |
| Jerry A. Peace | 43 | Chief Risk and Compliance Officer |

No family relationship exists between any of the Executive Officers of the Registrant. Messrs. Moore, Delaney, Hatfield, Huneryager, Renfrow, Nuttall, Forbes, Rowlett and Peace, Ms. Brockman and Ms. Fleming 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 18, 2006.



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 | 2001 – 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) |

| | | |
|---|---|---|
| James R. Hatfield | 2001 – Present: | Senior Vice President and Chief Financial Officer of Energy Corp. and the Company |
| Carla D. Brockman | 2005 – Present: | Vice President – Administration / Corporate Secretary of Energy Corp. and the Company |
| | 2002 – 2005: | Corporate Secretary of Energy Corp. and the Company |
| | 2002: | Assistant Corporate Secretary of Energy Corp. and the Company |
| | 2001 – 2002: | Client Manager – Strategic Planning of Energy Corp. and the Company |
| Steven R. Gerdes | 2003 – Present: | Vice President – Utility Operations of the Company |
| | 2001 – 2003: | Vice President – Shared Services of Energy Corp. and the Company |
| Gary D. Huneryager | 2005 – Present: | Vice President – Internal Audits of Energy Corp. and the Company |
| | 2002 – 2005: | Internal Audit Officer of Energy Corp. and the Company |
| | 2001 – 2002: | Assistant Internal Audit Officer of Energy Corp. and the Company |
| | 2001: | Service Line Director (Business Process Outsourcing) Arthur Andersen LLP |
| Melvin H. Perkins, Jr. | 2004 – Present: | Vice President – Transmission of the Company |
| | 2002 – 2003: | Director – Transmission Policy of the Company |
| | 2001– 2002: | Manager, Power Delivery Operations of the Company |
| Paul L. Renfrow | 2005 – Present: | Vice President – Public Affairs of Energy Corp. and the Company |
| | 2002 – 2005: | Director – Public Affairs of Energy Corp. and the Company |
| | 2002: | Manager, Corporate Communications of Energy Corp. and the Company |
| Reid Nuttall | 2006 – Present: | Vice President – Enterprise Information and Performance |
| | 2005 – 2006: | Vice President – Enterprise Architecture – National Oilwell Varco (oil and gas equipment company) |
| | 2001 – 2005: | Chief Information Officer, Vice President – Information Technology – Varco International (oil and gas equipment company) |



| Name | Business Experience | |
|---|---|---|
| Scott Forbes | 2005 – Present: | Controller and Chief Accounting Officer of Energy Corp. and the Company |
| | 2003 – 2005: | Chief Financial Officer – First Choice Power (electric utility) |
| | 2002 – 2005: | Senior Vice President and Chief Financial Officer – Texas New Mexico Power Company |
| | 2001 – 2002: | Vice President – Chief Accounting and Information Officer Texas New Mexico Power Company (electric utility) |
| Donald R. Rowlett | 2005 – Present: | Chief Accounting Policy Officer of Energy Corp. and the Company |
| | 2001 – 2005: | Vice President and Controller of Energy Corp. and the Company |
| Deborah S. Fleming | 2003 – Present: | Treasurer of Energy Corp. and the Company |
| | 2001 – 2003: | Assistant Treasurer – Williams Cos. Inc. (energy 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. |
| | 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.

During 2005, 2004 and 2003, the Company paid dividends of approximately $74.0 million, $107.6 million and $107.0 million to Energy Corp.



**Item 6. Selected Financial Data.**

**HISTORICAL DATA**

| | **2005** | 2004 | 2003 | 2002 | 2001 |
|---|---|---|---|---|---|
| SELECTED FINANCIAL DATA *(In millions)* | | | | | |
| Operating revenues | **$ 1,720.7** | $ 1,578.1 | $ 1,517.1 | $ 1,388.0 | $ 1,456.8 |
| Cost of goods sold | **994.2** | 914.2 | 837.3 | 695.7 | 766.3 |
| Gross margin on revenues | **726.5** | 663.9 | 679.8 | 692.3 | 690.5 |
| Other operating expenses | **494.3** | 471.6 | 463.5 | 453.1 | 453.7 |
| Operating income | **232.2** | 192.3 | 216.3 | 239.2 | 236.8 |
| Other income (loss) | **(2.3)** | 5.8 | 0.6 | 0.6 | 0.9 |
| Other expense | **3.0** | 2.7 | 3.2 | 3.1 | 3.5 |
| Net interest expense | **44.6** | 34.8 | 38.1 | 39.0 | 43.6 |
| Income tax expense | **52.6** | 53.0 | 60.2 | 71.6 | 69.4 |
| Net income | **$ 129.7** | $ 107.6 | $ 115.4 | $ 126.1 | $ 121.2 |
| Long-term debt | **$ 844.0** | $ 847.2 | $ 707.2 | $ 710.5 | $ 700.4 |
| Total assets | **$ 3,255.0** | $ 3,057.7 | $ 2,737.5 | $ 2,659.9 | $ 2,549.8 |
| CAPITALIZATION RATIOS (A) | | | | | |
| Stockholder's equity | **56.94%** | 55.64% | 56.54% | 56.00% | 56.93% |
| Long-term debt | **43.06%** | 44.36% | 43.46% | 44.00% | 43.07% |
| RATIO OF EARNINGS TO FIXED CHARGES (B) | | | | | |
| Ratio of earnings to fixed charges | **4.44** | 4.76 | 5.11 | 5.41 | 4.80 |

(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. The Company 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 related services for 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, 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**

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. As explained below, Energy Corp. intends to maintain the majority of its assets in the regulated utility business complemented by its natural gas pipeline business. The Company's long-term financial goals include earnings growth of four to five percent on a weather-normalized basis, an annual total return in the top third of its peer group, dividend growth and maintenance of strong credit ratings.

The Company has been focused on 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. As part of this plan, the Company purchased a 77 percent interest in the 520 megawatt ("MW") natural gas-fired combined cycle NRG McClain Station (the "McClain Plant") in July 2004. Capacity payment savings from reduced cogeneration payments and fuel savings from the McClain Plant will be utilized to help mitigate the price increases associated with these investments. In 2005 the Company filed a rate case to recover, among other things, its investment in, and the operating expenses of, the McClain Plant. An order was issued by the OCC on December 12, 2005 providing for a rate increase of approximately $42.3 million and the Company implemented the new electric rates in January 2006. For additional information regarding the McClain Plant acquisition, the new electric rates and related regulatory matters, see Note 12 of Notes to Financial Statements.

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, 2005, the Company and Enogex represented approximately 66 percent and 32 percent, respectively, of Energy Corp.'s consolidated assets. The remaining two 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 MW's of contracts with qualified cogeneration facilities ("QF") 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 MW's with PowerSmith Cogeneration Project, L.P. 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 as well as wind generation facilities.

On September 30, 2005, Energy Corp. and the Company entered into revolving credit agreements totaling $750 million. These agreements include two separate facilities, one for Energy Corp. in an amount up to $600 million and one for the Company in an amount up to $150 million. Each of the credit facilities has a five-year term with two options to extend the term for one year. These revolving credit agreements will provide sufficient liquidity to meet the Company's daily operational needs and capital improvements.

**Forward-Looking Statements**

Except for the historical statements contained herein, the matters discussed in the following discussion and analysis, including the discussion in "2006 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", “project” 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, coal 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; availability and prices of raw materials; federal or state legislation and regulatory decisions and initiatives that affect cost and investment recovery, have an impact on rate structures or 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 including Risk Factors to the Company’s Form 10-K for the year ended December 31, 2005.

**Overview**

***Summary of Operating Results***

**2005 compared to 2004.** The Company reported net income of approximately $129.7 million and $107.6 million for the years ended December 31, 2005 and 2004, respectively. The increase in net income was primarily due to warmer weather, customer growth and increased usage in the Company’s service territory partially offset by increased operating and maintenance expenses, depreciation expense, net interest expense and ad valorem taxes due to the acquisition of the McClain Plant, which ceased being recorded as a regulatory asset on July 8, 2005.

**2004 compared to 2003.** The Company reported net income of approximately $107.6 million and $115.4 million for the years ended December 31, 2004 and 2003, respectively. The decrease in net income was primarily due to cooler weather in the Company’s service territory and higher operating and maintenance expenses partially offset by gains from the sale of assets and lower net interest expense.

***Regulatory Matters***

**Gas Transportation and Storage Agreement**

As part of the settlement of a Company rate case in November 2002 (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. Because the required integrated service was not available in the marketplace from parties other than Enogex, 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 lost and unaccounted for gas on the transportation system. To the extent the Company transports gas in quantities in excess of the prescribed MDQ’s or MHQ’s, it pays an overrun service charge. During the years ended December 31, 2005, 2004 and 2003, the Company paid Enogex approximately $47.6 million, $49.6 million and $44.7 million, respectively, for gas transportation and storage services.

On July 14, 2005, the OCC issued an order in this case approving a $41.9 million annual recovery. The OCC order disallowed the recovery by the Company of the amount that Enogex charges the Company for the cost of fuel used, or otherwise unaccounted for, in providing natural gas transportation and storage service to the Company. Over the last three years, this amount has ranged from $1.2 million to $3.7 million annually. This amount was approximately $1.2 million in 2005 and is projected to be approximately $0.5 million in 2006. The OCC’s order required the Company to refund to its Oklahoma customers the difference between the amounts collected from such customers in the past based on an annual rate of $46.8 million for gas transportation and storage services and the $41.9 million annual rate authorized by the OCC’s order. Based on the order, the Company’s refund obligation was



approximately $8.8 million. The Company began refunding this obligation in September 2005 through its automatic fuel adjustment clause. The balance of the refund obligation was approximately $6.0 million at December 31, 2005. For further information, see Note 12 of Notes to Financial Statements.

In connection with the Enogex gas transportation and storage agreement, the Company has also recorded a refund obligation in Arkansas. The Company expects to meet with the APSC in early 2006 to determine the amount of the refund. The Company estimated its refund obligation to be approximately $1.1 million at December 31, 2005 to Arkansas customers assuming the Arkansas refund obligation is calculated consistent with the Oklahoma calculation.

**Oklahoma Rate Case Filing**

On May 20, 2005, the Company filed with the OCC an application for an annual rate increase of approximately $89.1 million to recover, among other things, its investment in, and the operating expenses of, the McClain Plant. The application also included, among other things, implementation of enhanced reliability programs in the Company's system, increased fuel oil inventory, the establishment of a separate recovery mechanism for major storm expense, the establishment of new rate classes for public schools and related facilities, the establishment of a military base rider, the establishment of a new low income assistance tariff and the proposal to make the guaranteed flat bill pilot tariff permanent for residential and small business customers.

On September 12, 2005, 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 a rate increase of approximately $13.0 million, one-seventh the amount requested by the Company in its May 20, 2005 application. The recommendations in the testimony of the Attorney General's office and the Oklahoma Industrial Energy Consumers recommended a rate decrease of approximately $24 million and $31 million, respectively. Hearings in the rate case began on October 10, 2005 and concluded on October 24, 2005. On November 3, 2005, the Referee appointed by the OCC for this proceeding issued a report recommending an estimated rate increase of approximately $42 million for the Company. On December 12, 2005, the OCC issued an order providing for a $42.3 million increase in rates and a 10.75 percent return on equity, based on a capital structure consisting of 55.7 percent equity and 44.3 percent debt. The new rates became effective in January 2006. Also included in the order, among other things, are new depreciation rates effective January 2006 and a provision which modified the Company's mechanism for the recovery of over or under recovered fuel costs from its customers to allow interest to be applied to the over or under recovery. For further information regarding this rate case, see Note 12 of Notes to Financial Statements.

***Coal Shipment Disruption***

In July 2005, the Company received notification from Union Pacific Railroad ("Union Pacific") that, in May 2005, Union Pacific and BNSF Railway ("BNSF") experienced successive derailments on the jointly-owned rail line serving the Southern Powder River Basin coal producers. According to Union Pacific, these two derailments were caused by track that had become unstable from an accumulation of coal dust in the roadbed combined with unusually heavy rainfall. BNSF, which maintains and operates the line, concluded that a significant part of the line needed to be repaired before normal train operations could resume. While the repairs were taking place, Union Pacific was unable to operate at full capacity from the Powder River Basin. In November 2005, Union Pacific notified the Company that the South Powder River Basin joint line force majeure condition that was declared in May 2005 had ended. On December 2, 2005, BNSF completed the enhanced joint line maintenance program which opened the way for a return to normal operating conditions. It is expected that as rail traffic improves, the Company will be able to increase its level of coal inventories. At December 31, 2005, the Company had slightly more than 20 days of coal supply for each of its coal-fired units at its Sooner and Muskogee generating plants.



**2006 Outlook**

Energy Corp.'s 2006 earnings guidance is $159 million to $169 million of net income, excluding any gains on asset sales. The 2006 outlook includes earnings guidance of $124 million to $128 million for the Company and an effective tax rate of 36.3 percent. Key assumptions are detailed below.

**Key assumptions for 2006 are:**

- Normal weather patterns are experienced;
- Gross margin on revenues ("gross margin") on weather–adjusted, retail electric sales increases approximately two percent;
- Oklahoma rate increase of approximately $42.3 million;
- The General Motors' Oklahoma City plant closes, as announced, in early 2006, which is expected to reduce the Company's gross margin by approximately $2.2 million annually;
- Operating and maintenance expenses increase approximately $7 million primarily due to increased employee and benefit costs as well as costs associated with the acquisition of the McClain Plant;
- Interest costs increase approximately $14 million primarily due to the acquisition of the McClain Plant and higher interest rates associated with variable debt;
- Capital expenditures for investment in the Company's generation, transmission and distribution system are approximately $237 million in 2006; and
- Funding for Energy Corp.'s pension plan may to be up to $90 million in 2006, of which up to $69.9 million may be allocated to the Company.

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.

**Results of Operations**

The following discussion and analysis presents factors which affected the Company's results of operations for the years ended December 31, 2005, 2004 and 2003 and the Company's financial position at December 31, 2005 and 2004. 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)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| Operating income | **$ 232.2** | $ 192.3 | $ 216.3 |
| Net income | **$ 129.7** | $ 107.6 | $ 115.4 |

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.



| *(Dollars in millions)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| Operating revenues | **$ 1,720.7** | $ 1,578.1 | $ 1,517.1 |
| Cost of goods sold | **994.2** | 914.2 | 837.3 |
| Gross margin on revenues | **726.5** | 663.9 | 679.8 |
| Other operation and maintenance | **309.2** | 301.9 | 294.8 |
| Depreciation | **134.4** | 122.7 | 121.8 |
| Taxes other than income | **50.7** | 47.0 | 46.9 |
| Operating income | **232.2** | 192.3 | 216.3 |
| Other income (loss) | **(2.3)** | 5.8 | 0.6 |
| Other expense | **3.0** | 2.7 | 3.2 |
| Interest income | **2.6** | 2.7 | 0.7 |
| Interest expense | **47.2** | 37.5 | 38.8 |
| Income tax expense | **52.6** | 53.0 | 60.2 |
| Net income | **$ 129.7** | $ 107.6 | $ 115.4 |
| Operating revenues by classification | | | |
| Residential | **$ 663.6** | $ 611.4 | $ 601.4 |
| Commercial | **418.9** | 389.9 | 372.5 |
| Industrial | **355.6** | 326.7 | 293.4 |
| Public authorities | **173.1** | 158.5 | 146.1 |
| Sales for resale | **67.7** | 57.0 | 57.7 |
| Provision for refund on gas transportation and storage case | **(2.0)** | (6.9) | --- |
| System sales revenues | **1,676.9** | 1,536.6 | 1,471.1 |
| Off-system sales revenues | **4.9** | 0.8 | 4.1 |
| Other | **38.9** | 40.7 | 41.9 |
| Total operating revenues | **$ 1,720.7** | $ 1,578.1 | $ 1,517.1 |
| MWH (A) sales by classification (in millions) | | | |
| Residential | **8.5** | 7.9 | 8.2 |
| Commercial | **6.0** | 5.7 | 5.8 |
| Industrial | **7.2** | 7.0 | 6.8 |
| Public authorities | **2.8** | 2.7 | 2.7 |
| Sales for resale | **1.5** | 1.4 | 1.5 |
| System sales | **26.0** | 24.7 | 25.0 |
| Off-system sales | **0.1** | 0.1 | 0.1 |
| Total sales | **26.1** | 24.8 | 25.1 |
| Number of customers | **745,493** | 735,008 | 725,470 |
| Average cost of energy per KWH (B) - cents | | | |

| | | | |
|---|---|---|---|
| Fuel | **3.011** | 2.887 | 2.454 |
| Fuel and purchased power | **3.300** | 3.436 | 3.128 |
| Degree days (C) | | | |
| Heating | | | |
| Actual | **3,159** | 3,114 | 3,488 |
| Normal | **3,631** | 3,650 | 3,631 |
| Cooling | | | |
| Actual | **2,163** | 1,839 | 1,898 |
| 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 degree days, with each degree of difference equaling one cooling degree day. If the calculated average is below 65 degrees, then 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.



**2005 compared to 2004.** The Company's operating income increased approximately $39.9 million or 20.7 percent in 2005 as compared to 2004. The increase in operating income was primarily attributable to higher gross margins partially offset by higher operating expenses.

Gross margin, which is operating revenues less cost of goods sold, was approximately $726.5 million in 2005 as compared to approximately $663.9 million in 2004, an increase of approximately $62.6 million or 9.4 percent. The gross margin increased primarily due to:

- warmer weather in the Company's service territory, which increased the gross margin by approximately $33.4 million;
- price variance due to sales and customer mix and rate increases authorized in the OCC order in December 2005 that are included in the unbilled revenue calculation at December 31, 2005, which increased the gross margin by approximately $13.2 million;
- new customer growth primarily in the residential and commercial sectors of the Company's service territory, which increased the gross margin by approximately $6.6 million; and
- increased demand by industrial customers in the Company's service territory, which increased the gross margin by approximately $5.8 million.

Cost of goods sold for the Company consists of fuel used in electric generation and purchased power. Fuel expense was approximately $795.4 million in 2005 as compared to approximately $645.1 million in 2004, an increase of approximately $150.3 million or 23.3 percent. The increase was primarily due to increased generation and a higher average cost of fuel per kwh. 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 2005 and 2004, the Company's fuel mix was 70 percent coal and 30 percent natural gas. Though the Company has a higher installed capability of generation from natural gas units of 58 percent, it has been more economical to generate electricity for our customers with lower priced coal. Purchased power costs were approximately $198.8 million in 2005 as compared to approximately $269.1 million in 2004, a decrease of approximately $70.3 million or 26.1 percent. The decrease was primarily due to the Company's completion of the acquisition of the McClain Plant in 2004, the termination of a power purchase contract in August 2004 which was replaced with a new contract in September 2004 and the scheduled decrease in cogeneration capacity payments for another power purchase contract, which became effective in January 2005.

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. 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.

Other operating and maintenance expenses were approximately $309.2 million in 2005 as compared to approximately $301.9 million in 2004, an increase of approximately $7.3 million or 2.4 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher salaries, wages, pension and other employee expenses of approximately $8.6 million; and
- higher materials and supplies expense of approximately $2.0 million.

These increases in other operating and maintenance expenses were partially offset by lower allocations from the holding company of approximately $6.9 million primarily due to lower miscellaneous corporate expenses. This variance includes other operating and maintenance expenses associated with the acquisition of the McClain Plant, which ceased being recorded as a regulatory asset on July 8, 2005.

Depreciation expense was approximately $134.4 million in 2005 as compared to approximately $122.7 million in 2004, an increase of approximately $11.7 million or 9.5 percent, primarily due to a higher level of depreciable plant in addition to depreciation expense associated with the acquisition of the McClain Plant, which ceased being recorded as a regulatory asset on July 8, 2005.



Taxes other than income was approximately $50.7 million in 2005 as compared to approximately $47.0 million in 2004, an increase of approximately $3.7 million or 7.9 percent, primarily due to increased ad valorem taxes. This variance includes ad valorem taxes associated with the acquisition of the McClain Plant, which ceased being recorded as a regulatory asset on July 8, 2005.

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 a loss of approximately $2.3 million in 2005 as compared to income of approximately $5.8 million in 2004, a decrease of approximately $8.1 million. The decrease in other income was primarily due to gains recognized in 2004 of approximately $3.5 million from the sale of the Company's interests in its natural gas producing properties and the sale of land near the Company's principal executive offices which gains were reversed in 2005 and reclassified to Other Deferred Credits and Other Liabilities in the Balance Sheet as a regulatory liability. Also contributing to the decrease in other income was a gain in 2004 of approximately $0.6 million from the repurchase of outstanding heat pump loans in addition to approximately $0.9 million due to the allowance for other funds used during construction in 2004.

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 $3.0 million in 2005 as compared to approximately $2.7 million in 2004, an increase of approximately $0.3 million or 11.1 percent which was primarily due to an increase of approximately $0.2 million in charitable contributions.

Net interest expense includes interest income, interest expense and other interest charges. Net interest expense was approximately $44.6 million in 2005 as compared to approximately $34.8 million in 2004, an increase of approximately $9.8 million or 28.2 percent. The increase in net interest expense was primarily due to:

- an increase in interest expense of approximately $4.3 million due to interest on debt associated with the McClain Plant acquisition, which the Company ceased recording as a regulatory asset on July 8, 2005;
- an increase in interest expense of approximately $4.2 million due to an increase in variable interest rates associated with the Company's interest rate swap agreement and variable rate industrial authority bonds; and
- an increase in interest expense of approximately $3.3 million for additional interest expense related to income taxes as a result of new guidelines issued by the Internal Revenue Service related to a change in the method of accounting used to capitalize costs for self-construction for income tax purposes only.

These increases in net interest expense were partially offset by:

- a decrease in interest expense of approximately $1.2 million due to lower interest rates on short-term debt used to temporarily fund the repayment of higher cost matured and called long-term debt; and
- a reduction in interest expense of approximately $0.5 million due to an increase in the allowance for borrowed funds used during construction.

Income tax expense was approximately $52.6 million in 2005 as compared to approximately $53.0 million in 2004, a decrease of approximately $0.4 million or 0.8 percent. The decrease in income tax expense was primarily due to:

- a reduction in tax accruals in 2005 related to Medicare Part D of approximately $2.6 million;
- a reduction in excess deferred taxes in 2005 of approximately $2.1 million; and
- an increase in Oklahoma state income tax credits of approximately $0.6 million in 2005 as compared to 2004.

These decreases in income tax expense were partially offset by higher pre-tax income for the Company.

**2004 compared to 2003.** The Company's operating income decreased approximately $24.0 million or 11.1 percent in 2004 as compared to 2003. The decrease in operating income was primarily attributable to lower gross margins and higher operating expenses.

Gross margin was approximately $663.9 million in 2004 as compared to approximately $679.8 million in 2003, a decrease of approximately $15.9 million or 2.3 percent. The gross margin decreased primarily due to:

- cooler weather in the Company's service territory which reduced the gross margin by approximately $15.7 million;
- 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
- the timing of fuel recoveries which decreased the gross margin by approximately $1.7 million.

These decreases in gross margin were partially offset by growth in the Company's service territory which increased the gross margin by approximately $4.9 million.

Fuel expense was approximately $645.1 million in 2004 as compared to approximately $544.4 million in 2003, an increase of approximately $100.7 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.

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:

- increased outside services expense of approximately $18.1 million;
- increased materials and supplies expense of approximately $2.0 million;
- increased employee expenses of approximately $2.0 million; and
- 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 lower salaries and wages expense of approximately $5.9 million and lower pension and benefit expense of approximately $6.4 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.

Other income was approximately $5.8 million in 2004 as compared to approximately $0.6 million in 2003, an increase of approximately $5.2 million. The increase in other income was primarily due to gains in 2004 of approximately $3.2 million from the sale of the Company's interests in its natural gas producing properties, approximately $0.6 million from the repurchase of outstanding heat pump loans and approximately $0.3 million from the sale of land and buildings near the Company's principal executive offices. Also contributing to the increase in other income was an increase of approximately $0.9 million due to the allowance for equity funds used during construction.



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 realized losses of approximately $0.4 million from the sale of miscellaneous assets in 2003.

Net interest expense was approximately $34.8 million in 2004 as compared to approximately $38.1 million in 2003, a decrease of approximately $3.3 million or 8.7 percent. The 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 $0.7 million due to the Company having lower average borrowing outstanding from the parent in 2004 as compared to 2003; and
- a reduction in interest expense of approximately $1.1 million due to an increase in the allowance for borrowed funds used during construction.

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.

**Financial Condition**

The balance of Accounts Receivable – Customers was approximately $139.1 million and $91.7 million at December 31, 2005 and 2004, respectively, an increase of approximately $47.4 million or 51.6 percent. The increase was primarily due to an increase in the Company's billings to its customers reflecting increased pass through of fuel costs resulting from significantly higher natural gas costs in December 2005 as compared to December 2004 and colder weather.

The balance of Fuel Inventories was approximately $27.9 million and $42.2 million at December 31, 2005 and 2004, respectively, a decrease of approximately $14.3 million or 33.9 percent. The decrease is primarily due to a decrease in coal inventories resulting from decreased coal deliveries from the Powder River Basin due to ongoing railroad repairs as described in "Overview – Coal Shipment Disruption."

The balance of Fuel Clause Under Recoveries was approximately $101.1 million and $54.3 million at December 31, 2005 and 2004, respectively, an increase of approximately $46.8 million or 86.2 percent. The increase in fuel clause under recoveries was due to the Company's cost of fuel exceeding the amount billed to the Company's customers in 2005. 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 are intended to allow the Company to amortize under or over recovery. In September 2005, the Company increased its Oklahoma fuel adjustment factor from 0.0112500 per kwh to 0.0171760 per kwh in order to reduce the under recovery.

The balance of Recoverable Take or Pay Gas Charges was approximately $4.9 million and $17.0 million at December 31, 2005 and 2004, respectively, a decrease of approximately $12.1 million or 71.2 percent. The balance of Provision for Payments of Take or Pay Gas was approximately $8.9 million and $21.0 million at December 31, 2005 and 2004, respectively, a decrease of approximately $12.1 million or 57.6 percent. The decrease was primarily due to the settlement of one of the two lawsuits reserved in the provision account.

The balance of McClain Plant deferred expenses was approximately $24.9 million and $11.0 million at December 31, 2005 and 2004, respectively, an increase of approximately $13.9 million. The increase was due to certain expenses including non-fuel operation and maintenance expenses, depreciation, cost of debt associated with the investment and ad valorem taxes being accrued as a regulatory asset for the 12-month period subsequent to the



completion of the McClain Plant acquisition. Such costs will be recovered over a four-year time period as authorized in the OCC order beginning in January 2006.

The balance of Accounts Payable – Other was approximately $113.1 million and $93.0 million at December 31, 2005 and 2004, respectively, an increase of approximately $20.1 million or 21.6 percent. The increase was primarily due to higher natural gas purchases in December 2005 as compared to December 2004 and timing of outstanding checks clearing the bank.

The balance of Advances from Parent was approximately $108.3 million and $10.2 million at December 31, 2005 and 2004, respectively, an increase of approximately $98.1 million. The increase was primarily due to the under recovery of fuel and higher working capital requirements primarily due to higher commodity prices and increased daily operational needs of the Company.

The balance of Accrued Pension and Benefit Obligations was approximately $183.5 million and $155.5 million at December 31, 2005 and 2004, respectively, an increase of approximately $28.0 million or 18.0 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 10 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***

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 repurchased in 2004 in addition to the heat pump loans the Company sold during 2002. The finance rate on the heat pump loans was based upon market rates and was reviewed and updated periodically. The Company's heat pump loan balance was approximately \$0.7 million and \$1.3 million at December 31, 2005 and 2004, respectively, and is included in Accounts Receivable, 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, 2005 (in millions) | \$ 2.2 |
| 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) | \$ 0.3 |

***Railcar Leases***

See Note 11 of Notes to Financial Statements for a discussion of the Company's railcar lease agreement.

**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) | \$ 661.0 | \$ 237.0 | \$ 424.0 | N/A | N/A |
| Maturities of long-term debt | 845.4 | --- | --- | \$ --- | \$ 845.4 |
| Interest payments on long-term debt | 996.1 | 47.6 | 95.1 | 95.1 | 758.3 |
| Pension funding obligations | 147.3 | 69.9 | 54.8 | 22.6 | N/A |

| | | | | | |
|---|---|---|---|---|---|
| Total capital requirements | 2,649.8 | 354.5 | 573.9 | 117.7 | 1,603.7 |
| Operating lease obligations | | | | | |
| Railcars | 56.3 | 4.3 | 7.9 | 7.5 | 36.6 |
| Other purchase obligations and commitments | | | | | |
| Cogeneration capacity payments | 476.4 | 98.6 | 192.5 | 185.3 | N/A |
| Fuel minimum purchase commitments | 832.5 | 184.3 | 359.0 | 202.4 | 86.8 |
| Total other purchase obligations and commitments | 1,308.9 | 282.9 | 551.5 | 387.7 | 86.8 |
| Total capital requirements, operating lease obligations and other purchase obligations and commitments | 4,015.0 | 641.7 | 1,133.3 | 512.9 | 1,727.1 |
| Amounts recoverable through automatic fuel adjustment clause (B) | (1,365.2) | (287.2) | (559.4) | (395.2) | (123.4) |
| Total, net | $ 2,649.8 | $ 354.5 | $ 573.9 | $ 117.7 | $ 1,603.7 |

(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 available



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. See Note 12 of Notes to Financial Statements for a discussion of the completed proceedings at the OCC regarding the Company's gas transportation and storage contract with Enogex.

**2005 Capital Requirements and Financing Activities**

Total capital requirements, consisting of capital expenditures, maturities of long-term debt, interest payments on long-term debt and pension funding obligations, were approximately $321.0 million in 2005. There were no contractual obligations, net of recoveries through automatic fuel adjustment clauses in 2005. Approximately $16.7 million of the 2005 capital requirements were to comply with environmental regulations. This compares to net capital requirements of approximately $480.6 million in 2004. There were no contractual obligations, net of recoveries through automatic fuel adjustment clauses in 2004. Approximately $4.8 million were to comply with environmental regulations. During 2005, 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) 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.

***Long-term Debt Maturities***

There are no maturities of the Company's long-term debt during the next five years.

***Interest Rate Swap Agreements***

See Note 8 Notes to Financial Statements for a discussion of the Company's interest rate swap agreement.

***Treasury Lock Agreements***

See Note 1 of Notes to Financial Statements for a discussion of the Company's treasury lock agreements.

**Future Capital Requirements**

***Capital Expenditures***

The Company's current 2006 to 2008 construction program includes continued investment in its distribution, generation and transmission system. 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 $3.6 million of the Company's capital expenditures budgeted for 2006 are to comply with environmental laws and regulations. The Company plans to continue to invest in its electric system at a level consistent with 2005. These capital expenditures do not include any capital requirements associated with the Company's proposed wind power project pending approval from the OCC. The Company has approximately 430 MW's of QF contracts that will expire at the end of 2007, unless extended by the Company. For one of these QF contracts, the Company purchases 100 percent of electricity generated by the QF. For the other QF contract, the Company can purchase up to 17 percent of electricity generated by the QF. In addition, effective September 1, 2004, the Company entered into a new 15-year power purchase agreement for 120 MW's with PowerSmith Cogeneration Project, L.P. ("PowerSmith"), in which the Company purchases 100 percent of electricity generated by 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 as well as wind generation facilities.

***Refinancing of Long-Term Debt***

In August 2005, the Company filed a Form S-3 Registration Statement to register the sale of up to $400.0 million of the Company's unsecured debt securities. On October 17, 2005, the Company paid at maturity its $110 million of 7.125 percent senior notes and redeemed its $110 million of 7.30 percent senior notes due October 15, 2025 at the principal amount plus a $3.6 million premium. The repayments were funded temporarily through the issuance of commercial paper by Energy Corp. and the Company and borrowings under existing credit agreements which the Company replaced with the proceeds from the issuance of $110 million of 5.15 percent senior notes and $110 million of 5.75 percent senior notes in January 2006.

***Pension and Postretirement Benefit Plans***

During 2005, actual asset returns for the Company's defined benefit pension plan were positively affected by growth in the equity markets; however, the growth in 2005 was not as strong as the growth in the equity markets in 2004. At December 31, 2005, approximately 59 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 2005, asset returns on the pension plan were approximately 6.20 percent as compared to approximately 12.51 percent in 2004. 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 decreased from approximately $69.0 million in 2004 to approximately $32.0 million in 2005. This decrease in pension plan funding in 2005 was due to the fact that in prior years additional amounts were contributed to the pension plan to maintain an adequate funded status. During 2006, Energy Corp. may contribute up to $90 million to the pension plan, of which up to $69.9 million may 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. Legislation is before Congress that if passed would change the funding requirements for defined benefit plans. The proposed legislation would generally provide employers less funding flexibility and require a higher funding level than required under current regulations. Management will continue to monitor the outcome of the legislation.

As discussed in Note 10 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 2005 and 2004, 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, 2005 and 2004 of approximately $88.9 million and $92.0 million, respectively, of which approximately $66.0 million and $67.0 million, respectively, were allocated to the Company. At December 31, 2005 and 2004, 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 $154.6 million and $123.3 million, respectively, of which approximately $127.6 million and $105.9 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 Statement of Financial Accounting Standards ("SFAS") No. 87, "Employers' Accounting for Pensions," required the recognition of an additional minimum liability in the amount of approximately $181.4 million and $156.6 million, respectively, for Energy Corp., of which approximately $157.3 million and $136.3 million, respectively, were allocated to the Company at December 31,



2005 and 2004. 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 2005 or 2004 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 and/or development of projects, 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 cash needs. 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***

See Note 9 of Notes to Financial Statements for a discussion of the Company's short-term debt activity.

**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 and cash flow 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 10 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 | +/- $21.2 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 legal 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 March 2005, the FASB issued FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations," in which an entity is required to recognize a liability for the fair value of an asset retirement obligation ("ARO") 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 ARO should be recognized when incurred. Uncertainty surrounding the timing and method of settlement of a conditional ARO should be factored into the measurement of the liability when sufficient information exists. However, in some cases, there is insufficient information to estimate the fair value of an ARO. In these cases, the liability should 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. FIN 47 required both recognition of a cumulative change in accounting principle and disclosure of the liability on a pro forma basis for transition purposes. FIN 47 is effective no later than the end of fiscal years ending after December 15, 2005. The Company adopted this new interpretation effective December 31, 2005 which resulted in an ARO of approximately $2.5 million being recorded for power plant structure legal obligations associated with various removal items, of which approximately $0.4 million is the ARO and approximately $2.1 million are cumulative accretion costs. Beginning January 1, 2006, the Company will amortize the remaining value of the related ARO assets over their remaining lives ranging from 20 to 50 years. The cumulative accretion costs of approximately $2.1 million that are included in the ARO were reclassified from the regulatory liability account associated with Accrued Removal Obligations to Asset Retirement Obligations on the Balance Sheet and, as a result, there was no earnings impact from a cumulative effect adjustment due to a change in accounting principle. In addition, the cumulative depreciation expense for the ARO assets of approximately $0.2 that would have been recorded for the time period from the date the liability would have been originally recorded under FIN 47 was also reclassified from the regulatory liability account to accumulated depreciation for the ARO assets with no earnings impact. At December 31, 2003 and 2004, the pro forma amount of the ARO would have been approximately $2.4 million. The Company has identified other ARO's that have not been recorded because the Company determined that these assets have indefinite lives primarily related to the Company's power plant sites.

The Company engages in cash flow and fair value hedge transactions to modify the rate composition of the debt portfolio. The Company has entered into an interest rate swap agreement and treasury lock agreements relating to managing interest rate exposure on the debt portfolio or anticipated debt issuances to modify the interest rate exposure on fixed rate debt issues. These interest rate swaps and treasury lock agreements qualify as fair value or cash flow hedges under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. The objective of the treasury lock agreements was to protect against the variability of future payments of interest expense of debt that was issued by the Company in January 2006.



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.

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, 2005, 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 $0.4 million. At December 31, 2005 and 2004, Accrued Unbilled Revenues were approximately $41.8 million and $45.5 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 final billing 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, 2005, if the provision rate were to increase or decrease by 10 percent, this would cause a change in the uncollectible expense recognized of approximately $0.2 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 $2.5 million and $2.7 million at December 31, 2005 and 2004, 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 retail restructuring efforts in Oklahoma and Arkansas have been postponed for the time being, if such efforts were renewed, retail competition and the unbundling of regulated energy service could have a significant financial impact on the Company due to an impairment of assets, a loss of retail customers, lower profit margins and/or increased costs of capital. Any such restructuring could have a significant impact on the Company's financial position, results of operations and cash flows. The Company cannot predict when it will be subject to changes in legislation or regulation, nor can it predict the impact of these changes on the Company's financial position, results of operations or cash flows. The Company believes that the prices for electricity and the quality and reliability of the Company's service currently place us in a position to compete effectively in the energy market. These developments at the federal and state levels as well as pending regulatory matters affecting the Company are described in more detail in Note 12 of Notes to Financial Statements.



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**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 legal 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 currently anticipate that liabilities arising out of these 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. See Note 11 of Notes to Financial Statements for a discussion of the Company's commitments and contingencies.

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

Market risks are, in most cases, risks that are actively traded in a marketplace and have been well studied in regards to quantification. Market risks include, but are not limited to, interest rates. The Company's exposure to changes in interest rates relates primarily to short-term variable-rate debt, interest rate swap agreements and commercial paper. The Company also engages in price risk management activities.

***Risk Committees and Oversight***

The Company monitors market risks using a risk committee structure. Energy Corp.'s Risk Oversight Committee, which consists primarily of corporate officers, is responsible for the overall development, implementation and enforcement of strategies and policies for all risk management activities of the Company. This committee's emphasis is a holistic perspective of risk measurement and policies targeting the Company's overall financial performance. The Risk Oversight Committee is authorized by and reports quarterly to the

Audit Committee of the Board of Directors of Energy Corp.

The Company also has a Corporate Risk Management Department led by our Chief Risk and Compliance Officer. This group, in conjunction with the aforementioned committees, is responsible for establishing and enforcing the Company's risk policies.

***Risk Policies***

The Company utilizes risk policies to control the amount of market risk exposure. These policies, which include value-at-risk limits, position limits, tenor limits and stop loss limits, are designed to provide the Audit Committee of the Board of Directors of Energy Corp. and senior executives of the Company with confidence that the risks taken on by the Company's business activities are in accordance with their expectations for financial returns and that the approved policies and controls related to risk management are being followed.

***Interest Rate Risk***

The Company's exposure to changes in interest rates relates primarily to short-term debt, interest rate swap agreements and commercial paper. The Company manages its interest rate exposure by limiting its variable rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. The Company utilizes interest rate derivatives to alter interest rate exposure in an attempt to reduce interest 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, 2005, the Company had no outstanding interest rate swap agreements. At December 31, 2004, 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



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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 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.

On September 1, 2005, the counterparty to the Company's interest rate swap agreement exercised its right to change the termination date of the interest rate swap agreement from October 15, 2025 to October 15, 2005 in conjunction with the early redemption of long-term debt discussed in Note 8 of Notes to Financial Statements. On October 17, 2005, the Company received approximately $5.3 million related to the termination of its interest rate agreement of which approximately $1.7 million is related to interest received and approximately $3.6 million is related to canceling the interest rate swap agreement, which will be amortized over the life of the long-term debt the Company issued in January 2006.

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

***Cash Flow Hedges of Interest Rates***

The Company entered into two separate treasury lock agreements, effective November 14, 2005 and November 16, 2005, respectively, to hedge approximately $50.0 million each of future interest payments of long-term debt that was issued in January 2006. These treasury locks were terminated in early December due to the lack of an OCC order in the Company's rate case at the time. The Company entered into two separate treasury lock agreements, effective December 28, 2005, to hedge approximately $50.0 million each of future interest payments of long-term debt that was issued in January 2006. These treasury locks were terminated on January 6, 2006 after the Company issued long-term debt. The Company received less than $0.1 million related to the termination of the aforementioned treasury lock agreements.

The fair value of the Company's long-term debt is based on quoted market prices. At December 31, 2005, the Company had no outstanding interest rate swap agreements. The following table shows the Company's long-term debt maturities and the weighted-average interest rates by maturity date.

| *(Dollars in millions)* | 2006 | Thereafter | Total | 12/31/05 Fair Value |
|---|---|---|---|---|
| Fixed rate debt (A) | | | | |
| Principal amount | $ --- | $ 710.0 | $ 710.0 | $ 731.7 |
| Weighted-average | | | | |

| | | | | |
|---|---|---|---|---|
| interest rate | --- | 6.20% | 6.20% | --- |
| Variable rate debt (B) | | | | |
| Principal amount | --- | $ 135.4 | $ 135.4 | $ 135.4 |
| Weighted-average | | | | |
| interest rate | --- | 2.62% | 2.62% | --- |

(A) Prior to or when these debt obligations mature, the Company may refinance all or a portion of such debt at then-existing market interest rates which may be more or less than the interest rates on the maturing debt.
(B) A hypothetical change of 100 basis points in the underlying variable interest rate would increase interest expense by approximately $1.4 million annually.

The Company may designate certain derivative instruments for the purchase or sale of electric power and fuel procurement as normal purchases and normal sales contracts under the provisions of SFAS No. 133. Normal purchases and normal sales contracts are not recorded in Price Risk Management assets or liabilities in the Balance Sheets and earnings recognition is recorded in the period in which physical delivery of the commodity occurs. The Company applies normal purchases and normal sales to electric power contracts by the Company and for fuel procurement by the Company.



***Credit Risk***

Credit risk includes the risk that counterparties that owe us money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and we could incur losses.

For the Company, new business customers are required to provide a security deposit in the form of cash, a 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.



**Item 8. Financial Statements and Supplementary Data.**

**OKLAHOMA GAS AND ELECTRIC COMPANY**
**BALANCE SHEETS**

| December 31 *(In millions)* | **2005** | 2004 |
|---|---|---|
| **ASSETS** | | |
| CURRENT ASSETS | | |
| Accounts receivable - customers, net | **$ 139.1** | $ 91.7 |
| Accounts receivable - other, net | **15.2** | 13.7 |
| Accrued unbilled revenues | **41.8** | 45.5 |
| Fuel inventories, at LIFO cost | **27.9** | 42.2 |
| Materials and supplies, at average cost | **52.6** | 50.3 |
| Accumulated deferred tax assets | **11.2** | 9.0 |
| Fuel clause under recoveries | **101.1** | 54.3 |
| Recoverable take or pay gas charges | **4.9** | 17.0 |
| Price risk management | **0.1** | --- |
| Prepayments and other | **10.2** | 6.0 |
| Total current assets | **404.1** | 329.7 |
| OTHER PROPERTY AND INVESTMENTS, at cost | **3.7** | 4.8 |
| PROPERTY, PLANT AND EQUIPMENT | | |
| In service | **4,745.9** | 4,539.0 |
| Construction work in progress | **80.8** | 94.4 |
| Other | **1.2** | 1.0 |
| Total property, plant and equipment | **4,827.9** | 4,634.4 |
| Less accumulated depreciation | **2,157.7** | 2,085.8 |
| Net property, plant and equipment | **2,670.2** | 2,548.6 |
| DEFERRED CHARGES AND OTHER ASSETS | | |

| | | |
|---|---|---|
| Income taxes recoverable from customers, net | **32.8** | 30.9 |
| Intangible asset - unamortized prior service cost | **26.5** | 31.8 |
| Prepaid benefit obligation | **65.4** | 67.2 |
| Price risk management | **---** | 3.9 |
| McClain Plant deferred expenses | **24.9** | 11.0 |
| Unamortized loss on reacquired debt | **21.3** | 21.0 |
| Unamortized debt issuance costs | **5.0** | 5.5 |
| Other | **1.1** | 3.3 |
| Total deferred charges and other assets | **177.0** | 174.6 |
| TOTAL ASSETS | **$ 3,255.0** | $ 3,057.7 |

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



**OKLAHOMA GAS AND ELECTRIC COMPANY**
**BALANCE SHEETS (Continued)**

| December 31 *(In millions)* | **2005** | 2004 |
|---|---|---|
| **LIABILITIES AND STOCKHOLDER'S EQUITY** | | |
| CURRENT LIABILITIES | | |
| Accounts payable - affiliates | **$ 10.7** | $ 8.7 |
| Accounts payable - other | **113.1** | 93.0 |
| Advances from parent | **108.3** | 10.2 |
| Customers' deposits | **46.3** | 45.6 |
| Accrued taxes | **22.9** | 20.4 |
| Accrued interest | **16.3** | 16.4 |
| Tax collections payable | **8.6** | 7.1 |
| Accrued vacation | **12.0** | 11.6 |
| Price risk management | **0.1** | 0.1 |
| Gas imbalances | **0.2** | 0.1 |
| Provision for payments of take or pay gas | **8.9** | 21.0 |
| Accrued compensation | **8.0** | 9.4 |
| Other | **13.3** | 12.0 |
| Total current liabilities | **368.7** | 255.6 |
| LONG-TERM DEBT | **844.0** | 847.2 |
| COMMITMENTS AND CONTINGENT LIABILITIES (Note 11) | | |
| DEFERRED CREDITS AND OTHER LIABILITIES | | |
| Accrued pension and benefit obligations | **183.5** | 155.5 |
| Accumulated deferred income taxes | **584.0** | 570.4 |
| Accumulated deferred investment tax credits | **31.7** | 36.8 |
| Accrued removal obligations, net | **114.3** | 122.2 |
| Asset retirement obligation | **3.6** | 1.1 |
| Other | **9.2** | 6.5 |
| Total deferred credits and other liabilities | **926.3** | 892.5 |
| STOCKHOLDER'S EQUITY | | |
| Common stockholder's equity | **665.4** | 665.5 |
| Retained earnings | **530.7** | 461.0 |
| Accumulated other comprehensive loss, net of tax | **(80.1)** | (64.1) |
| Total stockholder's equity | **1,116.0** | 1,062.4 |
| TOTAL LIABILITIES AND STOCKHOLDER'S EQUITY | **$ 3,255.0** | $ 3,057.7 |

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

**OKLAHOMA GAS AND ELECTRIC COMPANY**
**STATEMENTS OF CAPITALIZATION**

| December 31 *(In millions)* | | **2005** | 2004 |
|---|---|---|---|
| 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 | | **564.5** | 564.6 |
| Retained earnings | | **530.7** | 461.0 |
| Accumulated other comprehensive loss, net of tax | | **(80.1)** | (64.1) |
| Total stockholder's equity | | **1,116.0** | 1,062.4 |
| LONG-TERM DEBT | | | |
| SERIES | DATE DUE | | |
| Senior Notes | | | |
| 7.125% | Senior Notes, Series Due October 15, 2005 | **---** | 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 |
| 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** | 140.0 |
| Other bonds | | | |
| 1.56% - 3.71% | Garfield Industrial Authority, January 1, 2025 | **47.0** | 47.0 |
| 1.80% - 3.70% | Muskogee Industrial Authority, January 1, 2025 | **32.4** | 32.4 |
| 1.74% - 3.63% | Muskogee Industrial Authority, June 1, 2027 | **56.0** | 56.0 |
| Other long-term debt (NOTE 9) | | **220.0** | --- |
| Unamortized discount | | **(1.4)** | (2.2) |
| Total long-term debt | | **844.0** | 847.2 |
| Total Capitalization | | **$ 1,960.0** | $ 1,909.6 |

*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)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| OPERATING REVENUES | **$ 1,720.7** | $ 1,578.1 | $ 1,517.1 |
| COST OF GOODS SOLD (exclusive of depreciation shown below) | **994.2** | 914.2 | 837.3 |
| Gross margin on revenues | **726.5** | 663.9 | 679.8 |
| Other operation and maintenance | **309.2** | 301.9 | 294.8 |
| Depreciation | **134.4** | 122.7 | 121.8 |
| Taxes other than income | **50.7** | 47.0 | 46.9 |
| OPERATING INCOME | **232.2** | 192.3 | 216.3 |
| OTHER INCOME (EXPENSE) | | | |
| Other income (loss) | **(2.3)** | 5.8 | 0.6 |
| Other expense | **(3.0)** | (2.7) | (3.2) |
| Net other income (expense) | **(5.3)** | 3.1 | (2.6) |
| INTEREST INCOME (EXPENSE) | | | |
| Interest income | **2.6** | 2.7 | 0.7 |
| Interest on long-term debt | **(42.1)** | (36.9) | (36.9) |
| Allowance for borrowed funds used during construction | **2.2** | 1.7 | 0.5 |
| Interest on short-term debt and other interest charges | **(7.3)** | (2.3) | (2.4) |
| Net interest expense | **(44.6)** | (34.8) | (38.1) |
| INCOME BEFORE TAXES | **182.3** | 160.6 | 175.6 |

| | | | |
|---|---|---|---|
| INCOME TAX EXPENSE | **52.6** | 53.0 | 60.2 |
| NET INCOME | **$ 129.7** | $ 107.6 | $ 115.4 |

*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)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| BALANCE AT BEGINNING OF PERIOD | **$ 461.0** | $ 460.9 | $ 455.2 |
| ADD: Net income | **129.7** | 107.6 | 115.4 |
| Total | **590.7** | 568.5 | 570.6 |
| DEDUCT: Dividends declared on common stock | **60.0** | 107.5 | 109.7 |
| BALANCE AT END OF PERIOD | **$ 530.7** | $ 461.0 | $ 460.9 |

**OKLAHOMA GAS AND ELECTRIC COMPANY**
**STATEMENTS OF COMPREHENSIVE INCOME**

| Year ended December 31 (*In millions)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| Net income | **$ 129.7** | $ 107.6 | $ 115.4 |
| Other comprehensive income (loss), net of tax: | | | |
| Minimum pension liability adjustment [($26.1), ($17.4) and $16.5 pre-tax, respectively] | **(16.0)** | (10.7) | 10.1 |
| Total comprehensive income | **$ 113.7** | $ 96.9 | $ 125.5 |

*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)* | **2005** | 2004 | 2003 |
|---|---|---|---|

| | | | |
|---|---|---|---|
| CASH FLOWS FROM OPERATING ACTIVITIES | | | |
| Net Income | $ **129.7** | $ 107.6 | $ 115.4 |
| Adjustments to reconcile net income to net cash provided from operating activities | | | |
| Depreciation | **134.4** | 122.7 | 121.8 |
| Deferred income taxes and investment tax credits, net | **11.5** | 35.6 | 107.6 |
| Allowance for equity funds used during construction | **---** | (0.9) | --- |
| Gain on sale of assets | **---** | (3.2) | --- |
| Price risk management assets | **(0.1)** | --- | --- |
| Price risk management liabilities | **(0.1)** | 0.1 | --- |
| Other assets | **(4.9)** | (32.0) | (3.9) |
| Other liabilities | **(7.9)** | (0.6) | (3.2) |
| Change in certain current assets and liabilities | | | |
| Accounts receivable - customers, net | **(47.4)** | 31.4 | (25.3) |
| Accounts receivable - other, net | **(1.5)** | (3.8) | (1.8) |
| Accrued unbilled revenues | **3.7** | (7.5) | (9.8) |
| Fuel, materials and supplies inventories | **12.0** | (4.8) | 4.7 |
| Fuel clause under recoveries | **(46.8)** | (50.3) | 10.7 |
| Other current assets | **7.8** | 4.3 | (1.1) |
| Accounts payable | **20.1** | 35.3 | (5.4) |
| Accounts payable - affiliates | **2.0** | 5.5 | (4.8) |
| Customers' deposits | **0.7** | 9.8 | 2.7 |
| Accrued taxes | **2.5** | (0.2) | 0.3 |
| Accrued interest | **(0.1)** | 3.6 | (1.0) |
| Gas imbalances liability | **0.1** | 0.1 | --- |
| Fuel clause over recoveries | **---** | (32.4) | 32.4 |
| Other current liabilities | **(6.5)** | 5.3 | 6.3 |
| Net Cash Provided from Operating Activities | **209.2** | 225.6 | 345.6 |
| CASH FLOWS FROM INVESTING ACTIVITIES | | | |
| Capital expenditures (less allowance for equity funds used during construction) | **(249.1)** | (391.2) | (148.7) |
| Proceeds from sale of assets | **1.8** | 3.3 | --- |
| Net Cash Used in Investing Activities | **(247.3)** | (387.9) | (148.7) |
| CASH FLOWS FROM FINANCING ACTIVITIES | | | |
| Proceeds from long-term debt | **---** | 138.6 | --- |
| Retirement of long-term debt | **(220.0)** | --- | --- |
| Increase (decrease) in short-term debt, net | **332.1** | 127.3 | (86.2) |
| Dividends paid on common stock | **(74.0)** | (107.6) | (107.0) |
| Net Cash Provided from (Used in) Financing Activities | **38.1** | 158.3 | (193.2) |
| NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS | **---** | (4.0) | 3.7 |
| CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD | **---** | 4.0 | 0.3 |
| CASH AND CASH EQUIVALENTS AT END OF PERIOD | **$ ---** | $ --- | $ 4.0 |

*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. The Company 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 related services for 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, 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.

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)* | **2005** | 2004 |
|---|---|---|
| Regulatory Assets | | |
| Fuel clause under recoveries | **$ 101.1** | $ 54.3 |
| Income taxes recoverable from customers, net | **32.8** | 30.9 |
| McClain Plant deferred expenses | **24.9** | 11.0 |
| Unamortized loss on reacquired debt | **21.3** | 21.0 |
| Recoverable take or pay gas charges | **4.9** | 17.0 |
| Cogeneration credit rider under recovery | **3.7** | --- |
| January 2002 ice storm | **---** | 1.8 |
| Arkansas transition costs | **---** | 0.7 |
| Miscellaneous | **0.5** | 0.6 |
| Total Regulatory Assets | **$ 189.2** | $ 137.3 |
| | | |
| Regulatory Liabilities | | |
| Accrued removal obligations, net | **$ 114.3** | $ 122.2 |
| Deferred gain on sale of assets | **3.8** | --- |
| Total Regulatory Liabilities | **$ 118.1** | $ 122.2 |



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. In September 2005, the Company increased its Oklahoma fuel adjustment factor from 0.0112500 per kwh to 0.0171760 per kwh in order to reduce the under recovery. In accordance with the OCC order received by the Company in December 2005 in its rate case, beginning in January 2006, the Company's mechanism for the recovery of over or under recovered fuel costs from its customers was modified to allow interest to be applied to the over or under recovery.

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." At December 31, 2005, the balance of income taxes recoverable from customers, net was approximately $32.8 million. The OCC authorized approximately $30.1 million of the $32.8 million regulatory asset to be included in the Company's rate base for purposes of earning a return.

As a result of the acquisition of a 77 percent interest in the 520 megawatt ("MW") natural gas-fired combined cycle NRG McClain Station (the "McClain Plant") completed on July 9, 2004, and consistent with the 2002 agreed-upon settlement of a Company rate case (the "Settlement Agreement") with the OCC, the Company had 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. The Company's rate case application included an estimate of $25.9 million related to the McClain Plant regulatory asset. At December 31, 2005, the actual incurred expenses included in the McClain Plant regulatory asset were approximately $24.9 million. Such costs will be recovered over a four-year time period as authorized in the OCC rate order beginning in January 2006. The OCC also authorized approximately $15.5 million of the $24.9 million regulatory asset to be included in the Company's rate base for purposes of earning a return. See Note 12 for further information regarding this rate case.

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 amortized over the term of the long-term debt which replaced the previous long-term debt. The unamortized loss on reacquired debt is not included in the Company's rate base and does not otherwise earn a rate of return.

Recoverable take or pay gas charges represent the Company's estimate of the 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 recoverable take or pay gas charges are not included in the Company's rate base and do not otherwise earn a rate of return.

In January 2005, a cogeneration credit rider was implemented at the Company as part of the Oklahoma retail customer electric rates in order to return purchase power capacity payment reductions and any change in operating and maintenance expense related to cogeneration previously included in base rates to the Company's customers. The balance of the cogeneration credit rider under recovery was approximately \$3.7 million at December 31, 2005. Any 2005 over/under recovery of the cogeneration credit rider is automatically included in the 2006 rider. In December 2005, the OCC order in the Company's recently completed rate case authorized a new cogeneration credit rider effective January 2006. The 2006 cogeneration credit rider is approximately \$78.7 million and the 2005 under recovery was approximately \$3.7 million. The cogeneration credit rider under recovery is not included in the Company's rate base and does not otherwise earn a rate of return. The cogeneration credit rider under recovery is included in Prepayments and Other on the Company's Balance Sheets.



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.

During 2004, the Company sold assets including its interest in certain natural gas producing properties and the sale of land near the Company's principal executive offices for a gain of approximately \$3.5 million. During 2005, the Company sold certain assets for a gain of approximately \$0.3 million. In December 2005, the OCC order in the Company's recently completed rate case required that any previously recognized gain in 2004 related to the sale of assets should be returned to customers through electric rates at a rate of approximately \$1.3 million annually. During 2005, the Company reversed these gains and reclassified them to Other Deferred Credits and Other Liabilities as a regulatory liability. The Company recorded gains from the sale of assets in 2005 in a similar manner and expects to continue that treatment for future gains from the sale of assets.

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 and cash flow 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.

Under the Company's cash management arrangement with Energy Corp., the Company remits all excess cash to Energy Corp. who then funds the Company's controlled disbursement accounts as amounts are presented for payment. Outstanding checks in excess of cash balances were approximately \$32.0 million and \$21.7 million at December 31, 2005 and 2004, 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 final billing 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 $2.5 million and $2.7 million at December 31, 2005 and 2004, respectively.



New business customers are required to provide a security deposit in the form of cash, 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 $19.1 million and $13.7 million for 2005 and 2004, respectively, based on the average cost of fuel purchased. The amount of fuel inventory was approximately $27.9 million and $42.2 million at December 31, 2005 and 2004, respectively.

**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, overheads, transportation costs and the allowance for funds used during construction ("AFUDC"). Replacements of units of property are capitalized as plant. For group assets, the replaced plant is removed from plant balances and the cost of such property less net salvage is charged to Accumulated Depreciation. For non-group assets, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance is recorded as a loss in the Statements of Income as Other Expense. Repair and replacement of minor items of property are included in the Statements of Income as Other Operation and Maintenance Expense.

The Company owns a 77 percent in the McClain Plant and, as disclosed below, only the Company's 77 percent interest is reflected in the balances in the table below. The owner of the remaining 23 percent interest in the McClain Plant is the Oklahoma Municipal Power Authority ("OMPA"). The Company and OMPA are responsible for providing their own financing of capital expenditures. Also, only the Company's proportionate interest of any direct expenses of the McClain Plant such as fuel, maintenance expense and other operating expenses is included in the applicable financial statements captions in the Statements of Income. The balance of the Company's interest in the McClain Plant asset is approximately $174.0 million and $173.8 million, respectively, at December 31, 2005 and 2004. The accumulated depreciation associated with the Company's interest in the McClain Plant is approximately $14.3 million and $4.2 million, respectively, at December 31, 2005 and 2004.

The Company's property, plant and equipment are divided into the following major classes at December 31, 2005 and 2004, respectively.

| December 31 *(In millions)* | **2005** | 2004 |
|---|---|---|
| Distribution assets | **$ 2,048.0** | $ 1,934.0 |
| Electric generation assets | **1,870.9** | 1,828.3 |
| Transmission assets | **597.0** | 552.8 |
| Intangible plant | **8.6** | 6.3 |
| Other property and equipment | **303.4** | 313.0 |
| Total property, plant and equipment | **$ 4,827.9** | $ 4,634.4 |

**Depreciation**

The provision for depreciation, which was approximately 3.0 percent and 2.9 percent, respectively, of the average depreciable utility plant for 2005 and 2004, 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. During early 2005, a depreciation study for the Company was performed and new proposed depreciation rates were included as part of the Company's May 20, 2005 rate case application with the OCC. In the OCC rate order issued in December 2005, the

OCC approved the proposed depreciation rates which were implemented effective January 1, 2006. In 2006, the provision for depreciation is projected to be approximately 2.8 percent of the average depreciable utility plant. Amortization of intangibles other than debt costs is computed using the straight-line method. Approximately 75 percent of the intangible plant balance at December 31, 2005 will be amortized over three years with the remaining intangible plant being amortized over their respective lives ranging up to 25 years.

**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 3.78 percent, 4.99 percent and 1.67 percent for the years 2005, 2004 and 2003, respectively. The decrease in the AFUDC rates in 2005 was primarily due to a higher level of short-term borrowings in 2005.

**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.

**Stock-Based Compensation**

Pursuant to the provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," the Company has elected to continue using the intrinsic value method of accounting for its stock-based employee compensation plans in accordance with Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees." Accordingly, the Company has not recognized compensation expense for its stock-based awards to employees. See Note 7 for a further discussion related to Energy Corp.'s Stock Incentive Plan. Energy Corp. will adopt SFAS No. 123 (Revised), "Share-Based Payment," effective January 1, 2006, which will require Energy Corp. 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. The Company would have recognized approximately $0.1 million each in 2005, 2004 and 2003 had it elected to adopt the fair value based method of SFAS No. 123.

**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 an $80.1 million after tax loss ($130.7 million pre-tax) and approximately a $64.1 million after tax loss ($104.6 million pre-tax), respectively, at December 31, 2005 and 2004 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, 2005.



***Cash Flow Hedges of Interest Rates***

The Company entered into two separate treasury lock agreements, effective November 14, 2005 and November 16, 2005, respectively, to hedge approximately $50.0 million each of future interest payments of long-term debt that was issued in January 2006. These treasury locks were terminated in early December due to the lack of an OCC order in the Company's rate case at the time. The Company entered into two separate treasury lock agreements, effective December 28, 2005, to hedge approximately $50.0 million each of future interest payments of long-term debt that was issued in January 2006. These treasury locks were terminated on January 6, 2006 after the Company issued long-term debt. The Company received less than $0.1 million related to the termination of the aforementioned treasury lock agreements.

**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. 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 $86.2 million, $89.6 million and $84.4 million during 2005, 2004 and 2003, 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 "Distrigas" method. The Distrigas method is a three-factor formula that uses an equal weighting of payroll, net operating revenues and gross property, plant and equipment. The Company adopted the Distrigas method in January 1996 as a result of a recommendation by the OCC Staff. The Company believes this method provides a reasonable basis for allocating common expenses.

In 2005, 2004 and 2003, the Company paid Enogex Inc. and its subsidiaries ("Enogex") approximately $34.9 million, $34.3 million and $33.5 million, respectively, for transporting gas to the Company's natural gas-fired generating facilities. In 2005, 2004 and 2003, the Company paid Enogex approximately $12.7 million, $15.3 million and $11.2 million, respectively, for natural gas storage services. In 2005, 2004 and 2003, the Company also recorded natural gas purchases from Enogex of approximately $94.6 million, $45.2 million and $20.8 million, respectively. Approximately $11.2 million and approximately $8.4 million were recorded at December 31, 2005 and 2004, respectively, and are included in Accounts Payable – Affiliates in the Balance Sheet for these activities. See Note 13 for a discussion of the gas transportation and storage contract between the Company and Enogex.

In 2005, 2004 and 2003, the Company recorded interest income of approximately $0.3 million, $0.7 million and $0.1 million, respectively, from Energy Corp. for advances made by the Company to Energy Corp.

In 2005, 2004 and 2003, the Company recorded interest expense of approximately $1.0 million, $0.4 million and $1.1 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 2005, 2004 and 2003, the Company paid approximately $74.0 million, $107.6 million and $107.0 million, respectively, in dividends to Energy Corp.



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**Reclassifications**

Certain prior year amounts have been reclassified on the Financial Statements to conform to the 2005 presentation.

**2. Accounting Pronouncements**

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 does not expect the impact of this new standard to have a material effect on its financial position or results of operations.

In December 2004, the FASB issued SFAS No. 123 (Revised), which replaces SFAS No. 123 and supersedes APB Opinion No. 25. 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. Adoption of SFAS No. 123(R) is required for public entities as of the beginning of the first annual period beginning after June 15, 2005. The Company will adopt this new standard effective January 1, 2006. Management does not expect the impact of this new standard to have a material effect on its financial position or results of operations.

In March 2005, the FASB issued FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations," in which an entity is required to recognize a liability for the fair value of an asset retirement obligation ("ARO") 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 ARO should be recognized when incurred. Uncertainty surrounding the timing and method of settlement of a conditional ARO should be factored into the measurement of the liability when sufficient information exists. However, in some cases, there is insufficient information to estimate the fair value of an ARO. In these cases, the liability should 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. FIN 47 required both recognition of a cumulative change in accounting principle and disclosure of the liability on a pro forma basis for transition purposes. FIN 47 is effective no later than the end of fiscal years ending after December 15, 2005. The Company adopted this new interpretation effective December 31, 2005 which resulted in an ARO of approximately $2.5 million being recorded for power plant structure legal obligations associated with various removal items, of which approximately $0.4 million is the ARO and approximately $2.1 million are cumulative accretion costs. Beginning January 1, 2006, the Company will amortize the remaining value of the related ARO assets over their remaining lives ranging from 20 to 50 years. The cumulative accretion costs of approximately $2.1 million that are included in the ARO were reclassified from the regulatory liability account associated with Accrued Removal Obligations to Asset



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Retirement Obligations on the Balance Sheet and, as a result, there was no earnings impact from a cumulative effect adjustment due to a change in accounting principle. In addition, the cumulative depreciation expense for the ARO assets of approximately $0.2 that would have been recorded for the time period from the date the liability would have been originally recorded under FIN 47 was also reclassified from the regulatory liability account to accumulated depreciation for the ARO assets with no earnings impact. At December 31, 2003 and 2004, the pro forma amount of the ARO would have been approximately $2.4 million. The Company has identified other ARO's that have not been recorded because the Company determined that these assets have indefinite lives primarily related to the Company's power plant sites.

In June 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections," which replaces APB Opinion No. 20, "Accounting Changes" and SFAS No. 3, "Reporting Accounting Changes in Interim Financial Statements." SFAS No. 154 applies to all voluntary changes in accounting principle and requires retrospective application to prior periods' financial statements of changes in accounting principle unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. Adoption of SFAS No. 154 is required for accounting changes and error corrections made in fiscal years beginning after December 15, 2005. The Company will adopt this new standard effective January 1, 2006. Management does not expect the impact of this new standard to have a material effect 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 2005 and 2004, the Company's use of price risk management instruments involved the use of an interest rate swap agreement and treasury lock agreements. The interest rate swap 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. The treasury lock agreements protected against the variability of future interest payments of long-term debt that was issued by the Company in January 2006.

In accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, the Company recognizes its non-exchange traded 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. 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. If the forecasted transactions are no longer reasonably possible of occurring, any associated amounts recorded in Accumulated Other Comprehensive Income will also be recognized directly in earnings.

The Company may designate certain derivative instruments for the purchase or sale of electric power and fuel procurement as normal purchases and normal sales contracts under the provisions of SFAS No. 133. Normal purchases and normal sales contracts are not recorded in Price Risk Management assets or liabilities in the Balance Sheets and earnings recognition is recorded in the period in which physical delivery of the commodity occurs. The Company applies normal purchases and normal sales to electric power contracts by the Company and for fuel procurement by the Company.

At December 31, 2005, the Company had no outstanding interest rate swap agreements. At December 31, 2005, the Company's treasury lock agreements have been designated as cash flow hedges under SFAS No. 133. The Company measures ineffectiveness of the cash flow hedges under the hypothetical derivative method prescribed by SFAS No. 133. Under the hypothetical derivative method, the Company has designated that the critical terms of the



hedging instrument are the same as the critical terms of the hypothetical derivative used to value the forecasted transaction, and, as a result, no ineffectiveness is expected. See Note 1 for a description of the Company's treasury lock agreements.

## 4. 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)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| **NON-CASH INVESTING AND FINANCING ACTIVITIES** | | | |
| Change in fair value of long-term debt due to interest rate swap | **$ (3.9)** | $ (0.1) | $ (3.5) |
| Power plant long-term service agreement | **---** | 6.0 | --- |
| 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 $2.2, $1.7, $0.5) | **$ 50.2** | $ 33.6 | $ 35.9 |
| Income taxes (net of income tax refunds) | **43.1** | 22.9 | (39.8) |

## 5. Income Taxes

The items comprising income tax expense are as follows:

| Year ended December 31 *(In millions)* | **2005** | 2004 | 2003 |
|---|---|---|---|
| Provision (Benefit) for Current Income Taxes | | | |
| Federal | **$ 36.2** | $ 13.1 | $ (42.0) |
| State | **5.6** | 2.0 | (4.7) |
| Total Provision (Benefit) for Current Income Taxes | **41.8** | 15.1 | (46.7) |
| Provision (Benefit) for Deferred Income Taxes, net | | | |
| Federal | **18.2** | 38.5 | 99.4 |
| State | **(1.6)** | 2.2 | 13.4 |
| Total Provision (Benefit) for Deferred Income Taxes, net | **16.6** | 40.7 | 112.8 |
| Deferred Federal Investment Tax Credits, net | **(5.1)** | (5.2) | (5.2) |
| Income Taxes Relating to Other Income and Deductions | **(0.7)** | 2.4 | (0.7) |
| Total Income Tax Expense | **$ 52.6** | $ 53.0 | $ 60.2 |

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 2003 and all estimated payments made for 2002 have been refunded. Estimates made for 2003 were applied to 2004. Energy Corp. received federal and state income tax refunds of approximately $50.8 million during 2003 related to this tax accounting method change. During 2005, new guidelines were issued by the Internal Revenue Service ("IRS") related to the change in the method of accounting used to capitalize costs for self-construction discussed above. As part of Energy Corp.'s current IRS examination process, this change in method of accounting has been identified as an issue under examination. Energy Corp. believes its change in accounting method was in accordance with IRS regulations in effect at the time and will continue to vigorously defend its



position. While the outcome of this process is uncertain at this time, during 2005 the Company recorded approximately $3.3 million for additional interest expense related to income taxes as a result of a potential adjustment. This amount is included in Interest on Short-Term Debt and Other Interest Charges in the Statements of Income. The Company expects to continue to accrue approximately $0.3 million monthly in 2006 for additional interest expense related to this matter.

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

| Year ended December 31 | **2005** | 2004 | 2003 |
|---|---|---|---|
| Statutory federal tax rate | **35.0%** | 35.0% | 35.0% |
| State income taxes, net of federal income tax benefit | **1.2** | 1.7 | 3.2 |
| Tax credits, net | **(2.8)** | (3.2) | (2.9) |
| ESOP dividends | **(2.2)** | --- | --- |
| Medicare Part D subsidy | **(1.4)** | --- | --- |
| Excess deferred taxes (A) | **(1.2)** | --- | --- |
| Other, net | **0.2** | (0.5) | (1.0) |
| Effective income tax rate as reported | **28.8%** | 33.0% | 34.3% |

(A) During 2005, the Company performed a detailed analysis of all deferred tax assets and liabilities. In connection with this analysis, it was determined that an excess liability existed. The removal of this excess liability caused a permanent difference in the effective tax rate for 2005 of approximately 1.2 percent.

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, 2005 and 2004 respectively, are as follows:

| *(In millions)* | **2005** | 2004 |
|---|---|---|
| Current Accumulated Deferred Tax Assets | | |
| Accrued vacation | **$ 3.9** | $ 3.8 |
| Uncollectible accounts | **1.0** | 1.1 |
| Other | **6.3** | 4.1 |
| Total Current Accumulated Deferred Tax Assets | **$ 11.2** | $ 9.0 |
| Non-Current Accumulated Deferred Tax Liabilities | | |
| Accelerated depreciation and other property related differences | **$ 597.4** | $ 567.5 |
| Income taxes refundable to customers, net | **12.7** | 12.0 |
| Bond redemption-unamortized costs | **6.9** | 7.3 |
| Other | **0.4** | 1.5 |
| Total Non-Current Accumulated Deferred Tax Liabilities | **617.4** | 588.3 |
| Non-Current Accumulated Deferred Tax Assets | | |
| Company pension plan | **(13.5)** | (1.6) |

| | | | | | |
|---|---|---|---|---|---|
| Postretirement medical and life insurance benefits | | **(11.3)** | | (5.9) |
| Deferred federal investment tax credits | | **(8.6)** | | (10.4) |
| Total Non-Current Accumulated Deferred Tax Assets | | **(33.4)** | | (17.9) |
| Non-Current Accumulated Deferred Income Tax Liabilities, net | **$** | **584.0** | $ | 570.4 |



The Company has an Oklahoma investment tax credit carryover of approximately $6.8 million. These Oklahoma credit carryover amounts will begin expiring in the year 2017. During 2005, additional Oklahoma tax credits of approximately $3.8 million were generated by the Company. The Company believes that, based on current projections, the entire $10.6 million of these state tax credit amounts will be fully utilized in 2006.

In June 2005, Energy Corp. filed amended Oklahoma and Arkansas state income tax returns for the years 1993 through 2003. The returns were filed to reflect changes resulting from IRS audit adjustments as well as additional Oklahoma investment tax credits for assets placed into service prior to 2001. During the third quarter of 2005, the Company received approximately $1.6 million of the $3.8 million of state income tax and Oklahoma investment tax credit refunds for which it had applied. The Company expects to benefit from the remaining $2.2 million but is unable to predict the timing of the benefit.

***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 (the "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, are 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 October 20, 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. For 2005, Energy Corp.'s income tax benefit was approximately $0.5 million for the Company.

**6. Common Stock and Cumulative Preferred Stock**

There were no new shares of common stock issued during 2005, 2004 or 2003. The Company's Restated Certificate of Incorporation permits the issuance of a new series of preferred stock with dividends payable other than quarterly.

**7. Stock Incentive Plan**

On January 21, 1998, Energy Corp. adopted a Stock Incentive Plan (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. Energy Corp. has authorized the issuance of up to 2,700,000 shares under the 2003 Plan.

***Performance Units***

During 2005, 2004 and 2003, respectively, Energy Corp. awarded 201,794, 162,591 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. The 2003, 2004 and 2005 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. Also, for the 2005 performance units, the performance units are contingently awarded based on Energy Corp.'s earnings per share growth over a three-year award cycle. 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. During 2005, 2004 and 2003, the Company recorded approximately $0.2 million, $0.5 million and $0.3 million, respectively, related to expense for the performance units which are accounted for under the liability method.

***Stock Options***

During 2005, no stock options were granted under the 2003 Plan. 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:

| | **2005** | | 2004 | | 2003 | |
|---|---|---|---|---|---|---|
| | **Number of Options** | **Weighted Average Price** | Number of Options | Weighted Average Price | Number of Options | Weighted Average Price |
| Options Outstanding at beginning of year | **426,702** | **$22.88** | 430,867 | $22.28 | 349,800 | $23.96 |
| Granted | --- | --- | 63,700 | 23.58 | 117,000 | 16.69 |
| Employee migration (A) | **181,734** | --- | --- | --- | --- | --- |
| Exercised | **(150,169)** | **20.73** | (62,031) | 19.76 | (27,033) | 18.68 |
| Cancelled | **(16,800)** | **27.46** | (5,834) | 19.96 | (8,900) | 25.33 |
| Options Outstanding at end of year | **441,467** | **$23.08** | 426,702 | $22.88 | 430,867 | $22.28 |
| Options Exercisable at end of year | **375,057** | **$23.60** | 278,658 | $24.24 | 237,321 | $25.04 |

(A) Due to certain employees transferring between Energy Corp. and its subsidiaries.

The fair value of each option grant under the Plans for the years ended December 31, 2004 and 2003 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 and 2003. There were no stock option grants during 2005.

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

The following table provides additional information about stock options outstanding at December 31, 2005:

| | | 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 | 5.55 years | 222,933 | $ 20.03 | 189,726 | $ 20.62 |
| $23.58 - $28.75 | 4.09 years | 218,534 | $ 26.19 | 185,331 | $ 26.66 |



## 8. Long-Term Debt

A summary of the Company's long-term debt is included in the Statements of Capitalization. At December 31, 2005, the Company is in compliance with all of its debt agreements.

***Refinancing of Long-Term Debt***

In August 2005, the Company filed a Form S-3 Registration Statement to register the sale of up to $400.0 million of the Company's unsecured debt securities. On October 17, 2005, the Company paid at maturity its $110 million of 7.125 percent senior notes and redeemed its $110 million of 7.30 percent senior notes due October 15, 2025 at the principal amount plus a $3.6 million premium. The repayments were funded temporarily through the issuance of commercial paper by Energy Corp. and the Company and borrowings under existing credit agreements which the Company replaced with the proceeds from the issuance of $110 million of 5.15 percent senior notes and $110 million of 5.75 percent of senior notes in January 2006.

***Long-Term Debt with Optional Redemption Provisions***

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 can be tendered at the option of the holder during the next 12 months, are as follows (dollars in millions):

| SERIES | DATE DUE | AMOUNT |
|---|---|---|
| 1.56% - 3.71% | Garfield Industrial Authority, January 1, 2025 | **$ 47.0** |
| 1.80% - 3.70% | Muskogee Industrial Authority, January 1, 2025 | **32.4** |
| 1.74% - 3.63% | Muskogee Industrial Authority, June 1, 2027 | **56.0** |
| Total (redeemable during next 12 months) | | **$ 135.4** |

All of these Bonds are subject to an optional tender at the request 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. When a tender notice has been received by the trustee, a third party remarketing agent for the Bonds will attempt to remarket any Bonds tendered for purchase. This process occurs once per week. 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.

***Interest Rate Swap Agreements***

**Fair Value Hedge**

At December 31, 2005, the Company had no outstanding interest rate swap agreements. At December 31, 2004, 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 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.

On September 1, 2005, the counterparty to the Company's interest rate swap agreement exercised its right to change the termination date of the interest rate swap agreement from October 15, 2025 to October 15, 2005 in



conjunction with the early redemption of long-term debt discussed above. On October 17, 2005, the Company received approximately $5.3 million related to the termination of its interest rate agreement of which approximately $1.7 million is related to interest received and approximately $3.6 million is related to canceling the interest rate swap agreement, which will be amortized over the life of the long-term debt the Company issued in January 2006.

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

***Long-term Debt Maturities***

There are no maturities of the Company's long-term debt during the next five years.

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.

**9. Short-Term Debt**

At December 31, 2005, the Company had approximately $228.3 million in outstanding advances from Energy Corp. and approximately $100.0 million in outstanding commercial paper at a weighted-average interest rate of 4.40 percent. At December 31, 2004, the Company had approximately $10.2 million in outstanding advances from Energy Corp. In accordance with SFAS No. 6, "Classification of Short-Term Obligations Expected to Be Refinanced, an Amendment of ARB No. 43, Chapter 3A," $220 million in commercial paper and bank borrowings was used to temporarily fund the matured and called long-term debt for the Company. This commercial paper was classified as long-term debt in the Statement of Capitalization at December 31, 2005 as the Company planned to refinance this amount. Subsequently, the Company issued long-term debt in January 2006. The following table shows Energy Corp.'s and the Company's lines of credit in place, commercial paper outstanding and available cash at December 31, 2005. At December 31, 2005, Energy Corp.'s short-term borrowings consisted of commercial paper.

Lines of Credit, Commercial Paper and Available Cash *(In millions)*

| Entity | Amount Available | Amount Outstanding | Weighted-Average Interest Rate | Maturity |
|---|---|---|---|---|
| Energy Corp. (B) | $ 600.0 | $ 150.0 | 4.435% | September 30, 2010 (A) |
| The Company (C) | 150.0 | 100.0 | 4.400% | September 30, 2010 (A) |
| Energy Corp. | 15.0 | --- | N/A | April 6, 2006 |
| | 765.0 | 250.0 | 4.421% | |
| Cash | --- | N/A | N/A | N/A |
| Total | $ 765.0 | $ 250.0 | 4.421% | |

(A) On September 30, 2005, Energy Corp. and the Company entered into revolving credit agreements totaling $750 million. This credit facility agreement includes two separate facilities, one for Energy Corp. in an amount up to $600 million and one for the Company in an amount up to $150 million. Each of the credit facilities has a five-year term with two options to extend the term for one year.
(B) This bank facility is available to back up a maximum of $300.0 million of Energy Corp.'s commercial paper borrowings and to provide an additional $300.0 million in revolving credit borrowings. This bank facility can also be used as a letter of credit facility. At December 31, 2005, Energy Corp. had approximately $150.0 million in commercial paper borrowings.
(C) This bank facility is available to back up a maximum of $100.0 million of the Company's commercial paper borrowings and to provide an additional $50.0 million in revolving credit borrowings. At December 31, 2005, the Company had approximately $100.0 million in commercial paper borrowings and $0.2 million supporting a letter of credit.



Energy Corp.'s and the Company's ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruptions. Pricing grids associated with the back up lines of credit could cause annual fees and borrowing rates to increase if an adverse ratings impact occurs. 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., 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 for a two-year period beginning January 1, 2005 through December 31, 2006.

**10. 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. For employees hired on or after February 1, 2000, the pension plan is 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 a benefit 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 unless the employee's age and years of credited service equal or exceed 80.

It is Energy Corp.'s policy to fund the plan on a current basis based on the net periodic SFAS No. 87, "Employers' Accounting for Pensions," 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 2005 and 2004, Energy Corp. made contributions of approximately $32.0 million and $69.0 million, respectively, of which approximately $24.8 million and $54.5 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 2006, Energy Corp. may contribute up to $90 million to the plan, of which up to $69.9 million may 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 funding requirements specified by the Employee Retirement Income Security Act of 1974, as amended.

During 2005 and 2004, 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, 2005 and 2004 of approximately $88.9 million and

$92.0 million, respectively, of which approximately $66.0 million and $67.0 million, respectively, were allocated to the Company. At December 31, 2005 and 2004, 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 $154.6 million and $123.3 million, respectively, of which approximately $127.6 million and $105.9 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 required the recognition of an additional minimum liability in the amount of approximately $181.4 million and $156.6 million, respectively, for Energy Corp., of which approximately $157.3 million and $136.3 million, respectively, were allocated to the Company at December 31, 2005 and 2004. 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 2005 or 2004 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, 2005 and 2004:

| | **2005** | 2004 |
|---|---|---|
| Equity securities | **59 %** | 62 % |
| Debt securities | **36 %** | 36 % |
| Other securities | **5 %** | 2 % |
| Total | **100 %** | 100 % |

**Investment Policies and Strategies**

The plan assets are held in a trust which follows an investment policy and strategy designed to maximize the long-term investment returns of the 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 Committee (the "Committee").

The various investment managers used by the 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 an annual 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 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) on a fee adjusted basis 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 |
| Equity Index | S&P 500 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 | S&P 400 Midcap Index |
| Small-Cap Equity | Russell 2000 Index |
| International 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 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. At least 75 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") or Fitch Ratings ("Fitch"). 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. The purchase of any of Energy Corp.'s equity, debt or other securities is prohibited.

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 domestic 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 S&P 400 Midcap Index, small dividend yield, return on equity at or near the S&P 400 Midcap Index and earnings per share growth rate at or near the S&P 400 Midcap Index. The domestic 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 international global equity manager invests primarily in non-dollar denominated equity securities. Investing internationally diversifies the overall 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") is 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 international portfolio are thoroughly researched. 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).

For all domestic equity investment managers, no more than eight percent (five percent for mid-cap and small-cap equity managers) can be invested in any one stock at the time of purchase and no more than 16 percent (10 percent for mid-cap and small-cap equity managers) after accounting for price appreciation. A minimum of 95 percent of the total assets of an equity manager's portfolio must be allocated to the equity markets. Options or financial futures may not be purchased unless prior approval of the Committee is received. The purchase of securities on margin is prohibited as is securities lending. 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 fund for re-deployment. The purchase of any of Energy Corp.'s equity, debt or other securities is prohibited. The



purchase of equity or debt issues of the portfolio manager's organization is also prohibited. The aggregate positions in any company may not exceed one percent of the fair market value of its outstanding stock.

***Restoration of Retirement Income Plan***

The Company 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 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 credited service total or exceed 80 or have attained age 55 with 10 years of vesting service at the time of retirement are entitled to these postretirement benefits. Employees hired on or after February 1, 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)* | **2005** | 2004 | **2005** | 2004 |
| Beginning obligations | **$ (447.1)** | $ (404.0) | **$ (164.8)** | $ (156.1) |
| Service cost | **(12.7)** | (11.3) | **(2.3)** | (2.1) |
| Interest cost | **(24.6)** | (24.4) | **(8.9)** | (9.6) |
| Participants' contributions | **---** | --- | **(3.3)** | (2.6) |
| Plan changes/other | **---** | (1.3) | **---** | --- |
| Actuarial losses | **(29.1)** | (43.5) | **(8.6)** | (6.0) |
| Benefits paid | **35.3** | 37.4 | **12.1** | 11.6 |
| Ending obligations | **$ (478.2)** | $ (447.1) | **$ (175.8)** | $ (164.8) |

**Fair Value of Plans' Assets**

| | Pension Plan and Restoration of Retirement Income Plan | | Postretirement Benefit Plans | |
|---|---|---|---|---|
| *(In millions)* | **2005** | 2004 | **2005** | 2004 |
| Beginning fair value | **$ 341.2** | $ 286.4 | **$ 62.0** | $ 54.2 |
| Actual return on plans' assets | **19.1** | 37.6 | **4.4** | 9.0 |
| Employer contributions | **25.6** | 54.6 | **7.5** | 7.8 |
| Participants' contributions | **---** | --- | **3.3** | 2.6 |
| Benefits paid | **(35.3)** | (37.4) | **(12.1)** | (11.6) |
| Ending fair value | **$ 350.6** | $ 341.2 | **$ 65.1** | $ 62.0 |



**Net Periodic Benefit Cost**

| | Pension Plan and Restoration of Retirement Income Plan | | | Postretirement Benefit Plans | | |
|---|---|---|---|---|---|---|
| *(In millions)* | **2005** | 2004 | 2003 | **2005** | 2004 | 2003 |
| Service cost | **$ 12.7** | $ 11.3 | $ 10.3 | **$ 2.3** | $ 2.1 | $ 2.1 |
| Interest cost | **24.6** | 24.4 | 24.6 | **8.9** | 9.6 | 9.4 |
| Return on plan assets | **(27.4)** | (25.5) | (19.9) | **(5.2)** | (5.3) | (5.2) |
| Amortization of transition obligation | **---** | --- | --- | **2.5** | 2.5 | 2.5 |
| Amortization of net loss | **11.7** | 9.6 | 10.9 | **4.5** | 4.6 | 3.1 |
| Amortization of unrecognized prior service cost | **5.2** | 5.2 | 5.0 | **1.5** | 1.5 | 1.5 |
| Net periodic benefit cost | **$ 26.8** | $ 25.0 | $ 30.9 | **$ 14.5** | $ 15.0 | $ 13.4 |

The capitalized portion of the net periodic pension benefit cost was approximately $8.3 million, $7.8 million and $5.7 million at December 31, 2005, 2004 and 2003, respectively. The capitalized portion of the net periodic postretirement benefit cost was approximately $4.7 million, $4.7 million and $2.5 million at December 31, 2005, 2004 and 2003, respectively.

**Funded Status of Plans**

| (In millions) | Pension Plan and Restoration of Retirement Income Plan 2005 | 2004 | Postretirement Benefit Plans 2005 | 2004 |
|---|---|---|---|---|
| Funded status of the plans | **$ (127.6)** | $ (105.9) | **$ (110.7)** | $ (102.8) |
| Unrecognized net loss | **166.9** | 141.1 | **61.3** | 56.3 |
| Unrecognized prior service cost | **26.7** | 31.8 | **5.4** | 6.9 |
| Unrecognized transition obligation | **---** | --- | **17.8** | 20.3 |
| Net amount recognized | **$ 66.0** | $ 67.0 | **$ (26.2)** | $ (19.3) |

**Amounts recognized in the Balance Sheets consist of:**

| (In millions) | Pension Plan and Restoration of Retirement Income Plan 2005 | 2004 |
|---|---|---|
| Prepaid benefit obligation | **$ 66.0** | $ 67.2 |
| Accrued pension and benefit obligations | **(157.3)** | (136.5) |
| Intangible asset - unamortized prior service cost | **26.5** | 31.8 |
| Accumulated deferred tax asset | **50.6** | 40.4 |
| Accumulated other comprehensive loss, net of tax | **80.2** | 64.1 |
| Net amount recognized | **$ 66.0** | $ 67.0 |



**Rate Assumptions**

| | Pension Plan 2005 | 2004 | 2003 | Postretirement Benefit Plans 2005 | 2004 | 2003 |
|---|---|---|---|---|---|---|
| Discount rate | **5.50%** | 5.75% | 6.25% | **5.50%** | 5.75% | 6.25% |
| Rate of return on plans' assets | **8.50%** | 8.75% | 8.75% | **8.50%** | 8.75% | 8.75% |
| 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 | **9.00%** | 10.00% | 11.00% |
| Ultimate trend rate | **N/A** | N/A | N/A | **4.50%** | 4.50% | 4.50% |
| Ultimate trend year | **N/A** | N/A | N/A | **2011** | 2010 | 2010 |

N/A - not applicable

The overall expected rate of return on plan assets assumption was decreased from 8.75 percent in 2004 to 8.50 percent in 2005 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 $53.0 million in 2006, $50.7 million in 2007, $52.1 million in 2008, $53.0 million in 2009, $50.1 million in 2010 and an aggregate of $232.5 million in years 2011 to 2015. 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. Future health care cost trend rates are assumed to be nine percent in 2006 with the rates decreasing in subsequent years by one percentage point per year through 2010. A one-percentage point change in the assumed health care cost trend rate would have the following effects:

**ONE-PERCENTAGE POINT INCREASE**

| (In millions) | 2005 | 2004 | 2003 |
|---|---|---|---|
| Effect on aggregate of the service and interest cost components | **$ 1.4** | $ 1.5 | $ 1.5 |
| Effect on accumulated postretirement benefit obligations | **21.8** | 19.9 | 19.2 |

**ONE-PERCENTAGE POINT DECREASE**

| (In millions) | 2005 | 2004 | 2003 |
|---|---|---|---|
| Effect on aggregate of the service and interest cost components | **$ 1.1** | $ 1.2 | $ 1.2 |

| | | | |
|---|---|---|---|
| Effect on accumulated postretirement benefit obligations | **18.0** | 16.4 | 15.7 |

***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. 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. 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 $29.8 million as a result of savings to Energy Corp.'s postretirement medical plan by approximately $5.2 million annually, of which approximately $4.5 million is expected to be allocated to the Company. The $4.5 million in annual savings is comprised of a reduction of approximately $2.7 million from amortization of the $29.8 million gain due to the reduction of the APBO, a reduction in the interest cost on the APBO of approximately $1.5 million and a reduction in the service cost due to the subsidy of approximately $0.3 million.

The Company expects to pay gross benefits payments related to its postretirement benefit plans, including prescription drug benefits, of approximately $10.2 million in 2006, $10.2 million in 2007, $10.9 million in 2008, $11.6 million in 2009, $12.2 million in 2010 and an aggregate of $68.7 million in years 2011 to 2015. The Company expects to receive federal subsidy receipts provided by the Medicare Act of approximately $0.9 million in 2006, $1.1 million in 2007, $1.2 million in 2008, $1.3 million in 2009, $1.4 million in 2010 and an aggregate of $8.2 million in years 2011 to 2015. The Company did not receive any federal subsidy receipts in 2005; however, the Company's 2005 SFAS No. 106 expense reflects credit for the expected future subsidies, thus reducing the expense.

***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 $4.2 million, $3.9 million and $3.6 million during 2005, 2004 and 2003, 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 related to the Company's executive officers in this plan as Accrued Pension and Benefit Obligations and the Company accounts for the contributions related to the Company's directors in this plan as Other Deferred Credits and Other Liabilities in the Balance Sheets. The investment associated with these contributions is accounted for as Other Property and Investments in its 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 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.

## 11. Commitments and Contingencies

***Capital Expenditures***

The Company's capital expenditures are estimated at approximately: 2006 – $237.0 million, 2007 – $212.0 million and 2008 – $212.0 million.

***Operating Lease Obligations***

Future minimum payments for the below noncancellable operating lease are as follows:

| *(In millions)* | 2006 | 2007 | 2008 | 2009 | 2010 | 2011 and Beyond |
|---|---|---|---|---|---|---|
| Railcars | $ 4.3 | $ 4.0 | $ 3.9 | $ 3.8 | $ 3.7 | $ 36.6 |

Payments for operating lease obligations were approximately $5.4 million each in 2005, 2004 and 2003, respectively.

***Railcar Lease Agreement***

At December 31, 2005, the Company had a noncancellable operating lease with 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. On December 29, 2005, the Company entered into a new lease agreement for railcars effective February 1, 2006 with a new lessor as described below. At the end of the new lease term which is January 31, 2011, the Company has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If the Company chooses not to purchase the railcars or renew the lease agreement and the actual value of the railcars is less than the stipulated fair market value, the Company would be responsible for the difference in those values up to a maximum of approximately $29.9 million. 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. The Company has approximately 430 MW's of QF contracts that will expire at the end of 2007, unless extended by the Company. For one of these QF contracts, the Company purchases 100 percent of electricity generated by the QF. For the other QF contract, the Company can purchase up to 17 percent of electricity generated by the QF. In addition, effective September 1, 2004, the Company entered into a new 15-year power purchase agreement for 120 MW's with PowerSmith in which the Company purchases 100 percent of electricity generated by PowerSmith.

During 2005, 2004 and 2003, the Company made total payments to cogenerators of approximately $183.8 million, $203.5 million and $203.0 million, respectively, of which approximately $95.5 million, $155.3 million and $164.7 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: 2006 – $98.6 million, 2007 – $97.1 million, 2008 – $95.4 million, 2009 – $93.6 million and 2010 – $91.7 million. The minimum capacity payment amounts for 2008 through 2010 assume the Company elects to extend certain cogeneration contracts, which otherwise expire at the end of 2007.

***Fuel Minimum Purchase Commitments***

The Company purchased necessary fuel supplies of coal and natural gas for its generating units of approximately $163.5 million, $166.5 million and $157.3 million for the years ended December 31, 2005, 2004 and 2003, respectively. The Company has entered into purchase commitments of necessary fuel supplies of approximately: 2006 – $184.4 million, 2007 – $169.4 million, 2008 – $189.6 million, 2009 – $99.0 million, 2010 – $103.3 million and 2011 and Beyond – $86.8 million.

***Natural Gas Units***

The Company utilized a request for bid ("RFB") to acquire approximately 30 percent of its projected annual natural gas requirements for 2006. 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 2006 will be secured through a new RFB issued in the first quarter of 2006. 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.



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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 was held March 17 - 18, 2005. A ruling in this case by the special master was received in May 2005 which dismissed the Company and all Enogex parties named in these proceedings. This ruling has been appealed to the District Court of Wyoming. An oral argument on this appeal to the District Court was made on December 9, 2005 but there is no ruling in this case to date. The Company intends to vigorously defend this action. At this time, 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.

*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 was held April 1, 2005. Energy Corp. intends to vigorously defend this action. At this time, 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.

***Kaiser-Francis Litigation***

The Company has been sued by Kaiser-Francis Oil Company in District Court, Blaine County, Oklahoma. This case has been pending for more than 13 years. Plaintiff alleged 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 sought \$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 was permitted to amend its petition to include a claim based on theories of tort. Specifically, Plaintiff alleged that the Company engaged in tortious conduct by, among other things, falsifying documents, sponsoring false testimony and putting forward legal defenses, which were known by the Company to be without merit. If successful, Plaintiff believed that these theories could give Plaintiff a basis to seek punitive damages. This lawsuit was stayed from June 2002 through February 2005 during the appeal of a similar case filed by Kaiser-Francis in Grady County, Oklahoma.

On January 3, 2006, the trial court granted the Company's motion for partial summary judgment on Plaintiff's tort claim. This ruling struck from the lawsuit Plaintiff's claim of (i) approximately \$4.7 million in tort damages; and (ii) approximately \$11 million in punitive damages. On January 13, 2006, at a court-ordered settlement conference, a settlement was reached in the Blaine County case whereby the Company agreed to pay \$8.9 million to Kaiser-Francis. The suit was dismissed with prejudice on January 18, 2006 and this case is now closed. The Company believes that the settlement amount is recoverable through its regulated electric rates.



In the similar case in Grady County, Oklahoma, Kaiser-Francis alleged that the Company breached the terms of several gas purchase contracts in amounts set forth in the contracts. As previously reported in the Company's Form 10-Q for the quarter ended September 30, 2005, the case was settled and is now closed.

***Calpine Corporation Bankruptcy***

Calpine Corporation, Calpine Energy Services, L.P., and several other affiliates (collectively "Calpine") voluntarily filed for Chapter 11 bankruptcy protection from creditors on December 20, 2005 (Case No. 05-60200 (BRL)) United States Bankruptcy Court, S.D. of New York. A Calpine-owned power generation plant in Oklahoma is contractually obligated to provide capacity and energy to the Company. The Calpine plant also pays, through the Southwest Power Pool ("SPP"), for transmission services provided by the Company. The Company expects both arrangements to remain in effect; however, whether Calpine in its bankruptcy proceedings will ultimately reject these agreements with the Company is unknown.

***Environmental Laws and Regulations***

Approximately \$3.6 million of the Company's capital expenditures budgeted for 2006 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 \$55.3 million during 2006, as compared to approximately \$61.7 million in 2005. 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 March 10, 2005, the Environmental Protection Agency ("EPA") published the Clean Air Interstate Rule ("CAIR"). This rule is intended to control sulfur dioxide ("SO2") and nitrogen oxide ("NOX") emissions from utility boilers in order to minimize the interstate transport of air pollution. The state of Oklahoma is not listed as one of the states affected by the rule.

On March 25, 2005, the EPA issued the Clean Air Mercury Rule ("CAMR") to limit mercury emissions from coal-fired boilers. The CAMR is currently subject to legal challenges. The CAMR requires reductions in mercury in two phases, phase I beginning in 2010 and phase II in 2018. The CAMR is based on the cap and trade program that will allow utilities to purchase mercury allowances (if available) rather than reduce emissions. It is anticipated that the Company will need to obtain allowances or reduce its mercury emissions in Phase II by approximately 70 percent. The CAMR will also require continuous monitoring of mercury emissions from the Company's coal-fired boilers beginning in 2009. The cost to the Company of the CAMR has not yet been established because monitoring technology is still being developed. However, the cost to comply with the CAMR will be in addition to the cost of other emissions monitoring that is already in place pursuant to Title IV of the Clean Air Act Amendments of 1990.

On June 15, 2005, the EPA issued final amendments to its 1999 regional haze rule. These regulations are intended to protect visibility in national parks and wilderness areas ("Class I areas") throughout the United States. In Oklahoma, the Wichita Mountains are 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 to finalize the process of determining what, if any, impact emission sources in Oklahoma have on national parks and wilderness areas.

In September 2005, the Oklahoma Department of Environmental Quality ("ODEQ") informally notified affected utilities that they would be required to perform a study to determine their impact on visibility in Class I areas. If an impact from affected Company facilities is determined, the Company must propose emission controls to meet ODEQ requirements. Federal requirements are currently being incorporated into the state implementation plan through rulemaking. The study and proposed reductions or controls, if needed, must be submitted to the ODEQ by



December 2006. The Company will have five years from the date of approval of a compliance plan to institute any required reductions. If an impact is determined and the regulations remain in effect, then significant capital and operating expenditures will be required for the Company's Sooner, Muskogee, Seminole and Horseshoe Lake generating stations.

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, on June 21 and 22, 2005, both Tulsa and Oklahoma City experienced high levels of ozone. If Tulsa and Oklahoma City continue to have elevated ozone levels for the next three ozone seasons, they could face redesignation to non-attainment status. To help avoid redesignation, both Tulsa and Oklahoma City have entered into an "Early Action Compact" with the EPA whereby voluntary measures will be enacted to reduce ozone.

On April 25, 2005, the EPA published a finding that all 50 states failed to submit the interstate pollution transport plans required by the Clean Air Act as a result of the adoption of the revised ambient ozone and fine particle standards. Failure to submit these implementation plans began a two-year timeframe, starting on May 25, 2005, during which states must submit a demonstration to the EPA that they do not affect air quality in downwind states. Earlier in 2005 it was unclear whether this could be accomplished by the state of Oklahoma and it was previously reported that there may be future significant expenditures required by the Company if Oklahoma was determined to impact the air quality in downwind states. However, recent communications with the state of Oklahoma have affirmed they expect to be able to demonstrate no impact on other states and meet the May 25, 2007 deadline established by the EPA. Therefore, there should be no significant impact to the Company as a result of the April 25, 2005 finding.

On December 21, 2005, the EPA proposed lowering the 24-hour fine particulate ambient standard while retaining the annual standard at its current level. In addition, the EPA proposed a new standard for inhalable coarse particulates. Based on past monitoring data, it appears that Oklahoma may be able to remain in attainment if the standards are finalized as proposed. However if parts of Oklahoma d o become "non-attainment", reductions in emissions from the Company's coal-fired boilers could be required which may result in significant capital and operating expenditures.

The 1990 Clean Air Act includes an acid rain 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. Beginning in 2000, the Company became subject to more stringent SO2 emission requirements in Phase II of the acid rain program. These lower limits had no significant financial impact due to the Company's earlier decision to burn low sulfur coal. In 2005, the Company's SO2 emissions were well below the allowable limits.

The EPA allocated SO2 allowances to the Company starting in 2000 and the Company started banking allowances in 2001. In December 2005, the Company sold 3,700 allowances for approximately $5.7 million. This resulted in an increase in cash and a decrease in fuel clause under recoveries with no impact to earnings as the proceeds from these sales have been returned to the Company's customers. At December 31, 2005, the Company has banked approximately 42,520 allowances. In February 2006, the Company sold 6,312 allowances for approximately $8.9 million. See Note 12 for a discussion of the SO2 allowance joint filing made in February 2006 which proposes how the proceeds from the sale of SO2 allowances should be accounted for in the future.

With respect to the NOX regulations of the acid rain program 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 2005 were approximately 0.33 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 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, 2005, 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 2005. The fees for 2006 are estimated to be approximately the same as in 2005.

There have been a variety of unsuccessful legislative and litigation efforts to force mandatory control of utility emissions that allegedly contribute to climate change. If legislation is passed in the future requiring mandatory CO2 emission reductions to address climate change, this could have a tremendous impact on all coal-fired electric utilities, including the Company's operations by requiring the Company to significantly reduce the use of coal as a fuel source.

**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 2005, the Company obtained refunds of approximately $1.0 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 has one Oklahoma Pollutant Discharge Elimination System permit renewal pending. The Company expects that this permit will be issued during the first quarter of 2006. The Company expects that this permit, when finally issued, will continue to be reasonable in its requirements, allow operational flexibility and provide reductions in operating costs. Additionally, the Company has filed an application with the state of Oklahoma for a new wastewater discharge permit for one of its facilities. The Company expects that the wastewater discharge permit for this facility will be issued in the first or second quarters of 2006.

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. The EPA 316(b) rules for existing facilities became effective July 23, 2004. The Company has engaged a consultant who has developed the required documentation for four Company facilities. These documents were submitted to the state agency on December 7, 2005 for review and approval. The Company has also provided the state of Oklahoma with information and requests that, if approved by the state, may reduce the impact of the 316(b) rules on the Company because if the Company's position is approved, three of the four Company facilities would not be required to comply with the 316(b) rules. Depending on the ultimate analysis and final determinations regarding the 316(b) rules, capital and/or operating costs may increase at any affected Company generating facility.

***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 legal 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 currently anticipate that liabilities arising out of these 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.



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**12. 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, 2005 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 Company assets or income for affiliate transactions. In addition, the Energy Policy Act of 2005 enacted the Public Utility Holding Company Act of 2005, which in turn granted to the FERC access to the books and records of Energy Corp. and its affiliates as the FERC deems relevant to costs incurred by the Company or necessary or appropriate for the protection of utility customers with respect to jurisdictional rates.

**Completed Regulatory Matters**

***2002 Settlement Agreement***

On November 22, 2002, the OCC signed a rate order containing the provisions of the Settlement Agreement in a Company rate case. The Settlement Agreement provided 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 MW ("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 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 from 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. During 2005, the Company recovered approximately $1.8 million in annual net profits from off-system sales. Including this amount, the Company has recovered a total of $5.4 million related to the regulatory asset since December 31, 2002, which is in accordance with the Settlement Agreement. During 2005, the Company also credited as required 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. Beginning January 1, 2006, the annual net profits from off-system sales will be shared with 80 percent to the Company's Oklahoma customers and 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 appealed the OCC's order to the Oklahoma Supreme Court. The appeal was denied and the OCC order is considered final.

***Acquisition of Power Plant***

On July 9, 2004, the Company completed the acquisition of NRG McClain LLC's 77 percent interest in the 520 MW McClain Plant. This transaction was intended to satisfy the requirement in the Settlement Agreement to acquire New Generation. The McClain Plant, which includes natural gas-fired combined cycle combustion turbine units, 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.

The closing of the purchase of the McClain Plant was subject to 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 in which 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 ("AES"), opposed the Company's offer of settlement and filed competing offers of settlement. 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 certain transmission facilities designed to result in up to 600 MW of available transfer capability ("ATC") from the Redbud Energy LP ("Redbud") facility to the Company's control area; (ii) pending completion of these transmission upgrades, provide up to 600 MW of ATC into the Company's control area from the Redbud plant through changes to the dispatch of the Company's generating units; and (iii) hire an independent market monitor to oversee the Company's activity in its control area until the SPP implements a market monitor for the SPP regional transmission organization ("RTO"). The Company completed the installation of the capital improvements and notified the FERC in writing on May 31, 2005 that these were completed. The Company's obligation to redispatch its system to make 600 MW of ATC available to the Redbud power plant terminated upon completion of the transmission upgrades. The independent market monitor described above 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 submitted six quarterly reports each covering the quarterly periods subsequent to the McClain Plant acquisition. 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 has concluded that the Company has not acted in an anticompetitive manner through either dispatch of its generation or operation of its transmission system. Further, in the review of the disposition of requests for transmission service, the independent market monitor detected no improper behavior with regard to access to the Company's transmission system. In August 2005, the market monitor initiated a special investigation into the circumstances surrounding the denial by the SPP of a request by Redbud for 440 MW in June 2005 of firm transmission service to the Company. In its third quarter 2005 report, the market monitor concluded that differences in the SPP modeling assumptions and an error in modeling made by the SPP were the primary causes for the denial of service. The market monitor further stated that, if the FERC's July 2, 2004 order was based on the assumption that the McClain generating unit was not running to serve the Company's load, the ATC created by the mitigation upgrades completed by the Company in response to the FERC's order of July 2, 2004 matched the claims made by the Company. On September 21, 2005, the FERC issued a letter requesting the Company to provide information to confirm that the transmission facilities that the Company constructed to mitigate the effects of the acquisition of the McClain interest resulted in 600 MW of ATC from Redbud to the Company's control area. On October 3, 2005, the Company responded that the facilities it constructed complied with the settlement the FERC approved regarding the acquisition of the McClain interest and resulted in the 600 MW of ATC. Redbud responded that, when it requested transmission service commencing in June 2005 after the facilities were completed, the SPP denied Redbud's request for service and, therefore, argued



that the ATC was not created. The Company explained that the SPP's denial of service to Redbud was due to an error by the SPP. Nonetheless, in October and November 2005, Redbud and the Company filed additional pleadings addressing the ATC. On December 1, 2005, the FERC held a technical conference to address the issues regarding the ATC. On December 8, 2005, the FERC issued a notice requesting additional information regarding the ATC and asked parties to file initial post-conference comments on December 16, 2005 and reply comments on January 20, 2006. The Company, Redbud, and the SPP filed comments on December 16, 2005. The Company and Redbud filed reply comments on January 20, 2006. The Company filed additional comments on February 6, 2006. While the Company believes that no further action is warranted in this matter, it cannot predict what action the FERC ultimately could take.

The Company expects the addition 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. 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 achieve at least $75.0 million in savings during this period.

***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. Because the required integrated service was not available in the marketplace from parties other than Enogex, 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 lost and unaccounted for gas on the transportation system. To the extent the Company transports gas in quantities in excess of the prescribed MDQ's or MHQ's, it pays an overrun service charge. During the years ended December 31, 2005, 2004 and 2003, the Company paid Enogex approximately $47.6 million, $49.6 million and $44.7 million, respectively, for gas transportation and storage services.

On July 14, 2005, the OCC issued an order in this case approving a $41.9 million annual recovery. The OCC order disallowed the recovery by the Company of the amount that Enogex charges the Company for the cost of fuel used, or otherwise unaccounted for, in providing natural gas transportation and storage service to the Company. Over the last three years, this amount has ranged from $1.2 million to $3.7 million annually. This amount was approximately $1.2 million in 2005 and is projected to be approximately $0.5 million in 2006. The OCC's order required the Company to refund to its Oklahoma customers the difference between the amounts collected from such customers in the past based on an annual rate of $46.8 million for gas transportation and storage services and the $41.9 million annual rate authorized by the OCC's order. Based on the order, the Company's refund obligation was approximately $8.8 million. The Company began refunding this obligation in September 2005 through its automatic fuel adjustment clause. The balance of the refund obligation was approximately $6.0 million at December 31, 2005.

In connection with the Enogex gas transportation and storage agreement, the Company has also recorded a refund obligation in Arkansas. The Company expects to meet with the APSC in early 2006 to determine the amount of the refund. The Company estimated its refund obligation to be approximately $1.1 million at December 31, 2005 to Arkansas customers assuming the Arkansas refund obligation is calculated consistent with the Oklahoma calculation.



***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. 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. On December 21, 2004, the OCC issued an order approving the security rider. The Company expects to implement the security rider by mid-year 2006.

***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 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 a new cogeneration credit rider which lowered electric bills by approximately $80 million in 2005. Any 2005 over/under recovery of the cogeneration credit rider is automatically included in the 2006 rider. In December 2005, the OCC order in the Company's recently completed rate case authorized a new cogeneration credit rider effective January 2006. The 2006 cogeneration credit rider is approximately $78.7 million and the 2005 under recovery was approximately $3.7 million.

***Oklahoma Rate Case Filing***

On May 20, 2005, the Company filed with the OCC an application for an annual rate increase of approximately $89.1 million to recover, among other things, its investment in, and the operating expenses of, the McClain Plant. The application also included, among other things, implementation of enhanced reliability programs in the Company's system, increased fuel oil inventory, the establishment of a separate recovery mechanism for major storm expense, the establishment of new rate classes for public schools and related facilities, the establishment of a military base rider, the establishment of a new low income assistance tariff and the proposal to make the guaranteed flat bill pilot tariff permanent for residential and small business customers.

On September 12, 2005, 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 a rate increase of approximately $13.0 million, one-seventh the amount requested by the Company in its May 20, 2005 application. The recommendations in the testimony of the Attorney General's office and the OIEC recommended a rate decrease of approximately $24 million and $31 million, respectively. Hearings in the rate case began on October 10, 2005 and concluded on October 24, 2005. On November 3, 2005, the Referee appointed by the OCC for this proceeding issued a report recommending an estimated rate increase of approximately $42 million for the Company. On December 12, 2005, the OCC issued an order providing for a $42.3 million increase in rates and a 10.75 percent return on equity, based on a capital structure consisting of 55.7 percent equity and 44.3 percent debt. The new rates became effective in January 2006. Also included in the order, among other things, are new depreciation rates effective January 2006 and a provision which modified the Company's mechanism for the recovery of over or under recovered fuel costs from its customers to allow interest to be applied to the over or under recovery.



As part of the rate order issued by the OCC in December 2005, the Company received OCC approval for the creation of two new rate classes, Public Schools-Demand and Public Schools Non-Demand. These two classes of service will provide the Company flexibility to provide targeted programs for load management to public schools and their unique usage patterns. Another item approved in the order was the creation of service level fuel differentiation which allows customers to pay fuel costs that better reflect energy losses on a service level basis. The OCC order also approved a military base rider which demonstrates Oklahoma's continued commitment to our military partners. The Company's highly successful wind program was authorized to lower its cost on a per kwh basis, which provides subscribing customers the increased incentive to hedge against future natural gas prices. The order also enables the Company's low-income qualified customers to receive relief on their summer electric bills by waiving the customer charge on their monthly bills from June to September of each year. Also included in the Company's rate case application, but not approved, was the establishment of a separate recovery mechanism for major storm expense.

As provided in the 2002 Settlement Agreement, the Company had the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the completion of 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. The Company completed its acquisition of the McClain Plant on July 9, 2004. Accordingly, the Company ceased accruing various operating and related costs associated with the McClain Plant as a regulatory asset on July 8, 2005. At December 31, 2005, the actual incurred expenses included in the McClain Plant regulatory asset were approximately $24.9 million. Such costs will be recovered over a four-year time period as authorized in the OCC rate order beginning in January 2006. The OCC authorized approximately $15.5 million of the $24.9 million regulatory asset to be included in the Company's rate base for purposes of earning a return.

**Pending Regulatory Matters**

***Review of the Company's Fuel Adjustment Clause for Calendar Year 2003 and 2004***

The OCC routinely audits activity in the Company's fuel adjustment clause for each calendar year. On March 18, 2005, the OCC Staff filed Cause No. PUD 200500140 regarding "Application of the Public Utility Division Director for Public Hearing to Review and Monitor the Company's Fuel Adjustment Clause for Calendar Year 2003." On June 10, 2005, the OCC voted to combine this case with the Company's recently completed rate case discussed above. On August 25, 2005, the OCC Staff filed Cause No. PUD 200500327 regarding "Application of the Public Utility Division Director for Public Hearing to Review and Monitor the Company's Fuel Adjustment Clause for Calendar Year 2004." On September 27, 2005, the OCC consolidated these two proceedings into one proceeding. Intervenors in this proceeding include the OIEC, AES, Redbud and PowerSmith. Hearings in this proceeding are scheduled to begin May 11, 2006.

***Competitive Bidding and Prudence Reviews for Electric Utility Providers***

On March 10, 2005, the OCC filed Cause No. PUD 200500129 regarding "Inquiry of the Oklahoma Corporation Commission into Guidelines for Establishing Rules for Competitive Bidding and Prudence Reviews for Electric Utility Providers." As an electric utility provider, any such guidelines that were adopted would likely impact the Company. Technical conferences were held in April 2005, and a hearing and deliberations were held in early June. On June 10, 2005, the OCC voted to close this notice of inquiry and directed the OCC Staff to open a rulemaking to address the competitive bidding issue for electric utilities. A technical conference was held on October 28, 2005 and a hearing before the OCC began December 8, 2005. Rules were adopted by the OCC on January 18, 2006 and forwarded to the Governor for review and approval. If approved by the Governor, the rules will become effective immediately. The Company does not expect these rules to have a significant impact on its operations.

***Power Purchase Agreement Filings***

On February 4, 2005, Chermac Energy Corporation ("Chermac") and Sleeping Bear, LLC filed an application at the OCC (Cause No. PUD 200500059) seeking establishment of purchased power rates and a power purchase agreement with the Company pursuant to PURPA for Chermac's proposed Buffalo/Sleeping Bear wind



project. On April 28, 2005, Chermac and Sleeping Bear, LLC filed a second application at the OCC (Cause No. PUD 200500177) seeking establishment of purchased power rates and a power purchase agreement with the Company pursuant to PURPA for Chermac's proposed Sleeping Bear South wind project. On September 15, 2005, the ALJ heard arguments on why the application should or should not be dismissed. On October 20, 2005, the ALJ suspended the current procedural schedule so that the parties involved in the proceeding could enter into negotiations. Subsequently, Chermac effectively designated Invenergy Wind LLC as its agent for settlement discussions. On December 22, 2005, Energy Corp. issued a press release announcing that the Company had entered into a non-binding letter of intent to purchase a 120 MW wind farm planned for construction in northwestern Oklahoma. Invenergy Wind Development Oklahoma LLC ("Invenergy LLC") would develop the new wind power-generation facility to be owned and operated by the Company. The wind farm, north of Woodward in Harper County, is expected to cost approximately $195 million, including the cost of transmission interconnection facilities. A definitive Agreement To Engineer, Procure and Construct Wind Generation Energy System ("EPC Contract") was reached on February 20, 2006, subject to various conditions. Those conditions include agreement by the parties as to certain exhibits to the EPC Contract, approval of the EPC Contract by the Company's Board of Directors and approval of the EPC Contract by the Manager of Invenergy LLC, all of which have to be completed on or before March 13, 2006. In addition, 90 days subsequent to the occurrence of these events, the Company or Invenergy LLC have the unilateral right to terminate the EPC Contract if certain additional events have not occurred, including the following: (i) OCC approval of the terms of the EPC Contract and of a recovery rider providing the Company the opportunity to recover all costs associated with the wind facility, including transmission interconnection and transmission upgrade costs; (ii) completion by the SPP of all necessary transmission studies; (iii) Invenergy LLC's acquisition of certain land agreements; (iv) Invenergy LLC's execution of a contract acceptable to the Company with a balance of work contractor; and (v) Invenergy LLC's acquisition of certain permits. If all of these conditions are met, the new wind farm is expected to be constructed and producing power on or before December 31, 2006. OCC hearings are expected to occur in April 2006.

***Arkansas Rate Case Filing***

Beginning in January 2006, the Company began developing a rate case filing for the Arkansas jurisdiction. The Company expects to make a rate case filing in Arkansas by mid-year 2006 requesting an increase in electric rates. The amount of the requested increase has not yet been determined.

***SO2 Allowance Filing***

On February 10, 2006, the Company, the OCC Staff and AES filed a joint application with the OCC to determine the treatment of proceeds received from the Company's sale of SO2 allowances and how these proceeds will be shared between the Company and its customers. In the application, the parties propose that AES be held harmless from any reduction in the Company's coal costs caused by the sale of SO2 allowances and that the proceeds of such sales are shared 80 percent to the Company's Oklahoma customers and the remaining 20 percent to the Company. A credit rider is being requested to pass the proceeds from the sale of the SO2 allowances to Oklahoma customers. Any proceeds from the sale of SO2 allowances in the Arkansas and the FERC jurisdictions will flow through the Company's automatic fuel adjustment clause.

***Southwest Power Pool***

The Company is a member of the 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 an RTO. In a FERC order dated October 1, 2004, the SPP was granted RTO status, subject to the SPP submitting a further compliance filing. 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 approval of the SPP RTO application is not expected to significantly impact the Company's consolidated financial results.



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The regional state committee, which is comprised of commissioners of the applicable state regulatory commissions, finished its process of formulating a methodology for funding transmission expansion in the SPP control area by allocating costs of transmission expansion to the SPP members who benefit. The SPP Board of Directors adopted this plan and filed it with the FERC on February 28, 2005, Docket No. ER05-652. The FERC conditionally accepted the plan on April 21, 2005 with an effective date of May 5, 2005. The SPP made a second compliance filing on October 20, 2005 on various minor issues associated with the plan. On January 11, 2006, the FERC conditionally accepted the compliance filing, but required the SPP to make minor wording changes within 30 days. The SPP filed these minor wording changes on February 10, 2006.

The SPP filed on June 15, 2005, Docket No. ER05-1118, to create a real-time, offer-based imbalance energy market which will require cash settlements for over or under generation. Market participants, including the Company, will be required to submit resource plans and can submit offer curves for each resource available for dispatch. In addition, the filing contains provisions allowing the SPP to order certain dispatching of generating units and a market monitoring plan which provides a clear set of rules, the potential consequences if the rules are violated and the areas in which an independent market monitor will examine and report. The scheduled implementation date of the imbalance energy market is May 1, 2006. On September 19, 2005, the FERC rejected the June 15, 2005 filing; however, the FERC provided guidance for the SPP's follow-up filing. On January 4, 2006, the SPP filed its follow-up filing in Docket No. ER06-451 by submitting tariff revisions to incorporate imbalance energy market and market monitoring procedures.

On August 8, 2005, the SPP filed with the FERC for approval, Docket No. ER05-1285, which contained, among other items, a standard definition of "transmission" to be used in the SPP RTO. The definition provides a uniform basis for application of formula rates, exercise of functional control of the transmission system, planning and expansion of the transmission system, compensation of new transmission owners and provides for a three-year period for petitioning for deviations from the bright line definition. The basic definition of transmission facilities is similar to definitions accepted for other RTO's. On September 30, 2005, the FERC accepted the definition, with minor modification. On November 29, 2005, the SPP submitted a compliance filing consistent with the September 30 FERC directions for modification.

On August 5, 2004, the Company filed with the APSC in Docket 04-111-U an application for approval of its participation in the SPP RTO. The application was filed pursuant to the provisions of Arkansas code which requires that no public utility shall sell, lease, rent or otherwise transfer, in any manner, control of electric transmission facilities in this state without the approval of the APSC, provided that the approval is required only to the extent the transaction is not subject to the exclusive jurisdiction of the FERC or any other federal agency. On October 12, 2004, the SPP filed with the APSC in Docket 04-137-U an application for a Certificate of Public Convenience and Necessity for the limited purpose of managing and coordinating the use of certain transmission facilities located within the state of Arkansas. The APSC has consolidated these two dockets, among others, and a public hearing is scheduled for April 4, 2006.

***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. One party, Redbud, protested the Company and OERI filing and proposed that the FERC require the Company to adopt an economic dispatch program as a means to mitigate the Company's and OERI's generation market power. On March 15, 2005, the Company and OERI responded to Redbud's protest. In that response the Company and OERI reiterated that the information they initially filed demonstrates that they cannot exercise market power and that Redbud's proposal is beyond the scope of the proceeding. Another party, AES, has requested intervention in this case in protest. In June 2005, the FERC granted the Redbud and AES interventions.

On June 7, 2005, the FERC issued an order on the Company's and OERI's market-based rate filing. Because the Company and OERI failed the market share screen for the Company's control area, the FERC set the Company's and OERI's market-based sales in the Company's control area for investigation pursuant to Section 206 of the Federal Power Act to investigate whether the Company and OERI may continue to sell power at market-based rates in the Company's control area. The initiation of the investigation and imposition of the filing requirements do not constitute a finding that the Company and OERI can exercise market power. The Company and OERI have been requested to provide additional information that demonstrates to the FERC that they cannot exercise market power in the first-tier markets as well. However, the order conditionally allows the Company and OERI to sell power in first-tier markets subject to the Company and OERI providing additional information that clearly shows that they pass the market share screen for the first-tier markets. The Company and OERI provided that additional information on July 7, 2005. On August 8, 2005, the Company and OERI informed the FERC that they will: (i) adopt the FERC default rate mechanism for sales of one week or less that are delivered to customers in the Company's control area; and (ii) commit not to enter into any sales with a duration of between one week and one year to loads that are delivered to customers in the Company's control area. The Company and OERI also informed the FERC that any new agreements for long-term sales to loads that are delivered to customers in the Company's control area will be filed with the FERC under Section 205 and not under market based rate tariffs. Interventions and comments on the Company's and OERI's August 8, 2005 filing were due December 22, 2005. No party filed comments. On January 20, 2006, the FERC issued a Notice of Institution of Proceeding and Refund Effective Date for the purpose of establishing the date from which any subsequent market-based sales would be subject to refund in the event the FERC concludes after investigation that the Company possesses market power. The refund effective date is March 27, 2006. The Company and OERI do not know when the FERC will conclude this investigation or act on the August 8, 2005 filing.

***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.

***National Energy Legislation***

In August 2005, Congress passed and the President signed into law a comprehensive energy bill, portions of which are of interest to the Company and to the industry. There are several provisions in the bill that have a positive impact on the Company. Provisions minimizing the risk of future uneconomic purchased power contracts forced on



the Company under PURPA, tax incentives for investment in electric transmission and gas pipeline systems, mandatory reliability requirements by the North American Electric Reliability Council with oversight by the FERC and improved FERC siting authority for construction of electric transmission in disputed areas are included in the new law. Another significant provision for the utility industry is the repeal of the Public Utility Holding Company Act of 1935. This provision has minimal impact on the current operations of Energy Corp. The FERC is in the process of developing regulations and policies mandated by the new energy act, some of which could have significance for electric utilities such as the Company. In particular, the Company will closely monitor the FERC's implementation of the new statute's conditional elimination of utilities' obligation to purchase power from cogenerators. Similarly, the Company will closely monitor the FERC and U.S. Department of Energy proceedings with regard to rules on the new mandatory reliability regime governing all electric generators, new transmission incentives and the concept of economic or efficient dispatch.

***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 2005 legislative session, House Bills 1910 and 1386 were introduced that may have an impact on the Company. House Bill 1910 which proposed that electric utilities: (i) be granted the certainty of knowing that costs of transmission upgrades assigned by an RTO will be recoverable, (ii) be granted the certainty of knowing that costs for a pre-approved plan to handle state and federally mandated environmental upgrades will be recoverable; and (iii) be able to seek pre-approval for generation construction projects, passed the legislature and was signed into law on May 11, 2005, at which time it became effective. House Bill 1386 proposed that utilities be able to continue to serve and expand, if so desired, in service territories in which they currently serve but which a municipality annexes. Currently, there is some legal uncertainty as to whether utilities can expand in an area described above. House Bill 1386 would have removed that uncertainty, but the bill failed to be heard for a final vote in the Senate and it carried over in its current form in the legislative session which began February 2006.

***Arkansas***

In April 1999, Arkansas passed a law (the "Restructuring Law") calling for restructuring of the electric utility industry at the retail level. The Restructuring Law, which had initially targeted customer choice of electricity providers by January 1, 2002, was repealed in March 2003 before it was implemented. As part of the repeal legislation, electric public utilities were permitted to recover transition costs. 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. During the third quarter of 2005, the Company recovered all of these costs.

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. 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. 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.

## 13. 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:

| | **2005** | | 2004 | |
|---|---|---|---|---|
| *(In millions)* | **Carrying Amount** | **Fair Value** | Carrying Amount | Fair Value |

| | | | | |
|---|---|---|---|---|
| Price Risk Management Assets | | | | |
| Interest Rate Swap | **$ 0.1** | **$ 0.1** | $ 3.9 | $ 3.9 |
| Price Risk Management Liabilities | | | | |
| Interest Rate Swap | **$ 0.1** | **$ 0.1** | $ 0.1 | $ 0.1 |
| Long-Term Debt | | | | |
| Senior Notes | **$ 488.6** | **$ 511.7** | $ 711.8 | $ 764.2 |
| Industrial Authority Bonds | **135.4** | **135.4** | 135.4 | 135.4 |
| Other | **220.0** | **220.0** | --- | --- |

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, 2005 and 2004, 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, 2005. 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, 2005 and 2004, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, 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, 2005, 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 21, 2006 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 21, 2006



**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 (A) | **2005** | **$ 412.7** | **$ 612.9** | **$ 394.1** | **$ 301.0** |
| | 2004 | 326.4 | 535.9 | 411.5 | 304.3 |
| Operating income (loss) (A) | **2005** | **$ 10.4** | **$ 164.0** | **$ 55.0** | **$ 2.8** |
| | 2004 | (15.1) | 147.4 | 55.0 | 5.0 |
| Net income (loss) (A) | **2005** | **$ 2.3** | **$ 99.4** | **$ 29.7** | **$ (1.7)** |
| | 2004 | (14.1) | 91.3 | 30.4 | --- |

(A) In January 2005, a cogeneration credit rider was implemented at the Company as part of the Oklahoma retail customer electric rates in order to return purchase power capacity payment reductions and any change in operating and maintenance expense related to cogeneration previously included in base rates to the Company's customers. This rider resulted in the seasonal over or under collection of revenues as the rider is based on an equal monthly amount kwh usage as compared to actual kwh usage. Due to the seasonal rates of the Company's electric sales, this resulted in a temporary over collection of operating revenues in excess of the reduction in operating and maintenance expense for the first and second quarters of 2005 of approximately $5.9 million ($3.6 million after tax) and a temporary under collection of operating revenues in excess of the reduction in operating and maintenance expense for the third quarter of 2005 of approximately $10.0 million ($6.1 million). In August 2005, the Company determined that its net income should not be affected by over or under collections on a temporary or permanent basis, and accordingly, any difference should be deferred as a regulatory asset or liability. As a result, in order to better reflect the purchase power capacity payment reductions and any change in operating and maintenance expense related to cogeneration from January 1, 2005 to September 30, 2005, the Company recorded a regulatory asset of approximately $4.1 million in current assets as Prepayments and Other in the Balance Sheet and a corresponding $4.1 million increase to Operating Revenues in the Statement of Income. Going forward, the Company expects any over or under collections related to the cogeneration credit rider to be reflected as a regulatory asset or liability. The balance of the cogeneration credit rider under recovery was approximately $3.7 million at December 31, 2005. Any 2005 over/under recovery of the cogeneration credit rider is automatically included in the 2006 rider. In December 2005, the OCC order in the Company's recently completed rate case authorized a new cogeneration credit rider effective January 2006. The 2006 cogeneration credit rider is approximately $78.7 million and the 2005 under recovery was approximately $3.7 million.

**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 (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934).



**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, 2005. 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, 2005, 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/ Scott Forbes |
| James R. Hatfield, Senior Vice President and Chief Financial Officer | Scott Forbes, Controller and Chief Accounting Officer |



**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, 2005, 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, 2005, 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, 2005, 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, 2005 and 2004, 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, 2005 of Oklahoma Gas and Electric Company and our report dated February 21, 2006 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 21, 2006



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**Item 9B. Other Information.**

None.

**PART III**

**Item 10. Directors and Executive Officers of the Registrant.**

**Item 11. Executive Compensation.**

On February 22, 2006 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 compensation. Set forth below is a description of the actions taken.

**Approve Payout of 2005 Annual Incentive Awards**

In February 2005, 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 percent to 150 percent of such targeted amount. For 2005, the targeted amount ranged from 25 percent to 80 percent 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 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 percent on a Company consolidated earnings per share target established by the Committee (the "Earnings Target"), (ii) 25 percent on a combined operating and maintenance expense and capital expenditure target for the Company and OG&E established by the Committee (the "O&M/Capital Target"), and (iii) 25 percent on consolidated net income of Enogex and its subsidiaries (the "Unregulated Income Target"). At least two of these three corporate goals were used in establishing the corporate goals for all other executive officers. However, the weighting of the corporate goals was slightly different for the remaining executive officers. For four executive officers, the corporate goals were based 50 percent on the Earnings Target and 50 percent on the O&M/Capital Target, for five executive officers, the corporate goals were based 40 percent on the Earnings Target, 40 percent on the Unregulated Income Target and 20 percent on the return on invested capital of Enogex (the "ROIC Target") and for two executive officers, the corporate goals were based 40 percent on the Earnings Target, 30 percent on the Unregulated Income Target, 20 percent on the Earnings Before Interest and Taxes Target and 10 percent on the OGE Energy Resources, Inc. Operational Measures Target. For the remaining executive officers, the corporate goals were based 50 percent on the Earnings Target, 30 percent on the O&M/Capital Target and 20 percent on the Unregulated Income Target.

For 2005, corporate performance of the Earnings Target, the Unregulated Income Target and the ROIC Target exceeded the minimum levels of achievement established by the Committee and, consequently, the Committee on February 22, 2006 approved payouts under the Annual Incentive Plan to executive officers ranging from 19 percent to 136 percent of their base salaries and from approximately 75 percent to 99 percent of their targeted amounts. Corporate performance goals of the O&M/Capital Target did not exceed the minimum levels of achievement established by the Committee.



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

| | Payout as % of Target | Payout |
|---|---|---|
| Steven E. Moore | 99.07% | $594,405 |
| Peter B. Delaney | 99.07% | $329,399 |
| James R. Hatfield | 94.25% | $153,973 |
| Jack T. Coffman | 75.00% | $ 70,192 |
| Steven R. Gerdes | 75.00% | $ 47,632 |
| Dan P. Harris | 128.51% | $ 91,241 |

**Approve Payout of 2003 Long-Term Incentive Awards**

In January 2003, executive officers received as part of their long-term compensation performance units based on total shareholder return ("TSR") as compared to a peer group for the three-year period ended December 31, 2005. The Company's TSR for such period was at the 66th percentile of the peer group, which resulted in payouts of 139.5 percent of the performance units originally awarded in January 2003.

Based on the Company's stock price on February 22, 2006, the payouts, which are payable 1/3 in cash and 2/3 in stock, for the six most highly compensated executive officers of the Company are as follows:

| Named Executive Officer | Payout |
|---|---|
| Steven E. Moore | $ 1,207,041 |
| Peter B. Delaney | $ 586,208 |
| James R. Hatfield | $ 308,912 |
| Jack T. Coffman | $ 174,400 |
| Steven R. Gerdes | $ 93,760 |
| Danny P. Harris | $ 97,576 |

**Establishment of 2006 Annual Incentive Awards**

As previously disclosed, at its December 2005 meeting, the Committee approved the level of target incentive awards, expressed as a percentage of salary, with the officer having the ability, depending upon achievement of corporate goals, to receive from 0 percent to 150 percent of such targeted amount. For 2006, the targeted amount ranged from 85 percent of salary for Mr. Moore and 30 percent to 70 percent of salary for the other named executive officers.

At its February 22, 2006 meeting, the Company established the performance goals for such awards. 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 percent on a Company consolidated earnings per share target established by the Committee (the "Earnings Target"), (ii) 25 percent on a combined operating and maintenance expense and capital expenditure target for the Company and OG&E established by the Committee (the "O&M/Capital Target"), and (iii) 25 percent on consolidated net income of Enogex and its subsidiaries (the "Unregulated Income Target"). At least two of these three corporate goals were used in establishing the corporate goals for all other executive officers. However, the weighting of the corporate goals was slightly different for the remaining executive officers. For two executive officers, the corporate goals were based 50 percent on the Earnings Target and 50 percent on the O&M/Capital Target, for six executive officers, the corporate goals were based 40 percent on the Earnings Target, 40 percent on the Unregulated Income Target and 20 percent on the return on invested capital of Enogex (the "ROIC Target") and for one executive officer, the corporate goals were based 40 percent on the Earnings Target, 37.5 percent on the Unregulated Income Target, 20 percent on the ROIC Target and 2.5 percent on the OGE Energy Resources, Inc. Operational Measures Target. For the remaining executive officers, the corporate goals were based 50 percent on the

Earnings Target, 30 percent on the O&M/Capital Target and 20 percent on the Unregulated Income Target.



**Establishment of Long-Term Awards**

As previously disclosed, at its December 2005 meeting, the Committee approved the level of target long-term incentive awards, expressed as a percentage of salary.

For 2006, 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 February 8, 2006 with a vesting factor applied. This resulted in executive officers receiving performance units with an expected value at the date of grant of from 30 percent to 150 percent of their 2006 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 percent to 200 percent of the performance units contingently awarded to the executive depending upon corporate performance. At its February 22, 2006 meeting, the Committee determined that for 75 percent 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 percent 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 | 59,288 |
| Peter B. Delaney | 31,012 |
| James R. Hatfield | 15,967 |
| Steven R. Gerdes | 3,724 |
| Danny P. Harris | 7,915 |

**Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.**

**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 2005 were $2,107,307 for Energy Corp.'s 2005 financial statement audit. These fees include $775,500 for the audit of internal control over financial reporting pursuant to the requirements of Sarbanes-Oxley section 404 and $37,321 for services in support of debt and stock offerings. Total audit fees for 2004 were $1,942,965, which includes $923,125 for the audit of internal control over financial reporting pursuant to the requirements of Sarbanes-Oxley section 404 and $66,614 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 2005, this amount includes estimated billings for the completion of the 2005 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, 2005 were $82,500, of which $67,500 was for employee benefit plan audits and $15,000 for other audit-related services.

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.

**Tax Fees**

The aggregate fees billed for tax services for the fiscal year ended December 31, 2005 were $292,096. These fees include $198,758 for tax preparation and compliance ($76,732 for the review of federal and state tax returns and $122,026 for assistance with examinations and other return issues), $93,338 for other tax services.

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, Oklahoma sales and use tax, $181,248 for a change in our tax accounting method and $65,540 for other tax services.

**All Other Fees**

These were no other fees billed to Energy Corp. in 2005 and 2004 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 2005, 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, Financial Statement Schedules.**

**(a) 1. Financial Statements**

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

- Balance Sheets at December 31, 2005 and 2004
- Statements of Capitalization at December 31, 2005 and 2004
- Statements of Income for the years ended December 31, 2005, 2004 and 2003



- Statements of Retained Earnings for the years ended December 31, 2005, 2004 and 2003
- Statements of Comprehensive Income for the years ended December 31, 2005, 2004 and 2003
- Statements of Cash Flows for the years ended December 31, 2005, 2004 and 2003
- Notes to Financial Statements

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

**Supplementary Data**

- Interim Financial Information

| **2. Financial Statement Schedule (included in Part IV)** | **Page** |
|---|---|
| Schedule II - Valuation and Qualifying Accounts | 99 |

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** |
|---|---|
| 1.01 | Underwriting Agreement, dated January 4, 2006 between the Company and J.P. Morgan Securities Inc. and Wachovia Capital Markets, LLC, on behalf of themselves and the other underwriters named therein relating to $110,000,000 in aggregate principal amount of the Company's 5.15% Senior Notes, Series due January 15, 2016 and $110,000,000 in aggregate principal amount of its 5.75% Senior Notes, Series due January 15, 2036 (collectively, the "Senior Notes"). (Filed as Exhibit 1.01 to the Company's Form 8-K filed January 6, 2006 (File No. 1-1097) and incorporated by reference herein) |
| 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 filed August 20, 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) |



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| 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) |

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| 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 filed October 24, 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 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 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 October 20, 2000 (File No. 1-1097) and incorporated by reference herein) |



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| 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 filed August 6, 2004 (File No 1-1097) and incorporated by reference herein) |
| 4.08 | Supplemental Indenture No. 7 dated as of January 1, 2006 being a supplemental instrument to Exhibit 4.01. hereto (Filed as Exhibit 4.08 to the Company's Form 8-K filed January 6, 2006 (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 | Energy Corp.'s 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) |

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|---|---|
| 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) |



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|---|---|
| 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 | 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) |
| 10.15 | Intrastate Firm No-Notice, Load Following Transportation and Storage Services Agreement dated as of May 1, 2003 between the Company and Enogex. [Confidential Treatment has been requested for certain portions of this exhibit.] (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) |
| 10.16 | 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) |
| 10.17 | Directors' Compensation. (Filed as Exhibit 10.24 to Energy Corp.'s Form 10-K for the year ended December 31, 2005 (File No. 1-12579) and incorporated by reference herein) |
| 10.18 | Executive Officer Compensation. (Filed as Exhibit 10.25 to Energy Corp.'s Form 10-K for the year ended December 31, 2005 (File No. 1-12579) and incorporated by reference herein) |
| 10.19 | 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) |
| 10.20 | 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) |
| 10.21 | 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) |

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|---|---|
| 10.22 | 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) |
| 10.23 | Credit agreement dated September 30, 2005, 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 filed October 5, 2005 (File No. 1-12579) and incorporated by reference herein) |
| 10.24 | Consulting agreement dated as of December 1, 2005, by and between Energy Corp. and Jack T. Coffman. (Filed as Exhibit 10.01 to Energy Corp.'s Form 8-K filed November 21, 2005 (File No. 1-12579) and incorporated by reference herein) |
| 10.25 | Amendment No. 6 to the OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.33 to Energy Corp.'s Form 10-K for the year ended December 31, 2005 (File No. 1-12579) and incorporated by reference herein) |
| 12.01 | Calculation of Ratio of Earnings to Fixed Charges. |



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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. |
| 99.02 | Copy of OCC order 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 8-K filed December 16, 2005 (File No. 1-12579) and incorporated by reference herein) |
| | <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 | Energy Corp.'s 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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10.14 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 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)

10.17 Directors' Compensation. (Filed as Exhibit 10.24 to Energy Corp.'s Form 10-K for the year ended December 31, 2005 (File No. 1-12579) and incorporated by reference herein)

10.18 Executive Officer Compensation. (Filed as Exhibit 10.25 to Energy Corp.'s Form 10-K for the year ended December 31, 2005 (File No. 1-12579) and incorporated by reference herein)

10.19 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)

10.20 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)

10.21 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)

10.22 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)

10.24 Consulting agreement dated as of December 1, 2005, by and between Energy Corp. and Jack T. Coffman. (Filed as Exhibit 10.01 to Energy Corp.'s Form 8-K filed November 21, 2005 (File No. 1-12579) and incorporated by reference herein)

10.25 Amendment No. 6 to the OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.33 to Energy Corp.'s Form 10-K for the year ended December 31, 2005 (File No. 1-12579) and incorporated by reference herein)



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**OKLAHOMA GAS AND ELECTRIC COMPANY**

**SCHEDULE II - Valuation and Qualifying Accounts**

| Description | Balance at Beginning of Period | Additions: Charged to Costs and Expenses | Additions: Charged to Other Accounts | Deductions | Balance at End of Period |
|---|---|---|---|---|---|
| | | (In millions) | | | |
| **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 |
| **Year Ended December 31, 2005** | | | | | |
| Reserve for Uncollectible Accounts | $2.7 | $3.3 | $--- | $3.5 (A) | $2.5 |

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



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**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 24th day of February, 2006.

**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<br>Steven E. Moore | Principal Executive Officer and Director; | February 24, 2006 |
| / s / James R. Hatfield<br>James R. Hatfield | Principal Financial Officer; and | February 24, 2006 |
| / s / Scott Forbes<br>Scott Forbes | Principal Accounting Officer. | February 24, 2006 |
| Herbert H. Champlin | Director; | |
| Luke R. Corbett | Director; | |
| William E. Durrett | Director; | |
| John D. Groendyke | Director; | |
| Robert Kelley | Director; | |
| Linda P. Lambert | Director; | |
| Robert Lorenz | Director; | |
| Ronald H. White, M.D. | Director; and | |
| J. D. Williams | Director. | |

/ s / Steven E. Moore
By Steven E. Moore (attorney-in-fact) February 24, 2006



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**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.



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**Exhibit 12.01**

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

| | Year Ended Dec 31, 2001 | Year Ended Dec 31, 2002 | Year Ended Dec 31, 2003 | Year Ended Dec 31, 2004 | Year Ended Dec 31, 2005 |
|---|---|---|---|---|---|
| Earnings: | | | | | |
| Pre-tax income | $190,631,943 | $197,572,191 | $175,604,686 | $160,634,550 | $182,280,019 |
| Add Fixed Charges | 49,953,948 | 44,577,061 | 42,582,265 | 42,234,286 | 52,379,698 |
| Subtotal | 240,585,891 | 242,149,252 | 218,186,951 | 202,868,836 | 234,659,717 |
| Subtract: | | | | | |
| Allowance for funds used during construction | 707,822 | 905,189 | 538,624 | 1,661,732 | 2,232,715 |
| Total Earnings | 239,878,069 | 241,244,063 | 217,648,327 | 201,207,104 | 232,427,002 |
| Fixed Charges: | | | | | |
| Long-term debt interest expense | 42,256,284 | 38,171,798 | 36,899,911 | 36,890,073 | 42,117,662 |
| Other interest expense | 4,438,997 | 3,044,837 | 2,443,702 | 2,246,574 | 7,314,465 |
| Calculated interest on leased property | 3,258,667 | 3,360,426 | 3,238,652 | 3,097,639 | 2,947,571 |
| Total Fixed Charges | $49,953,948 | $44,577,061 | $42,582,265 | $42,234,286 | $52,379,698 |
| Ratio of Earnings to Fixed Charges | 4.80 | 5.41 | 5.11 | 4.76 | 4.44 |



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**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 and the Registration Statement (Form S-3 No. 333-127843) pertaining to debt securities, of our reports dated February 21, 2006, 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, 2005.

/s/ Ernst & Young LLP

Ernst & Young LLP

Oklahoma City, Oklahoma
February 21, 2006



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**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, 2005; 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 SCOTT FORBES 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 18th day of January, 2006.

| | |
|---|---|
| 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 |
| John D. Groendyke, Director | / s / John D. Groendyke |
| Robert Kelley, Director | / s / Robert Kelley |
| Linda P. Lambert, Director | / s / Linda P. Lambert |
| Robert Lorenz, Director | / s / Robert Lorenz |
| 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 |
| Scott Forbes, Principal Accounting Officer | / s / Scott Forbes |

STATE OF OKLAHOMA )
) SS
COUNTY OF CANADIAN )

On the date indicated above, before me, Shirley Phinney, 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 18th day of January, 2006.

/s/ Shirley Phinney
Shirley Phinney
Notary Public in and for the County
of Canadian, State of Oklahoma

My Commission Expires:
March 7, 2006

**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 24, 2006

/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 24, 2006

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



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**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, 2005, 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 24, 2006

/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”, “believe”, “estimate”, “expect”, “intend”, “objective”, “plan”, “possible”, “potential”, “project” 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:

- 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;
- 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;
- Ability to negotiate franchise agreements with municipalities and counties in Oklahoma;
- Rate-setting policies or procedures of regulatory entities, including environmental externalities;
- 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;
- 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 defaults;
- Economic conditions including availability of credit, actions of rating agencies and that impact on our ability to access the capital markets, inflation rates and monetary fluctuations;
- Customer business conditions including demand for their products or services and supply of labor and materials used in creating their products and services;
- 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;
- Environmental laws, safety laws or other regulations passed by EPA, the Oklahoma Department of Environmental Quality or other governing agency that may impact the cost of operations or restricts or changes the way the Company operates its facilities;
- 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;

- Employee workforce factors including changes in key executives and employee retention;
- 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 11 of Notes to Financial Statements of the Company's Annual Report on Form 10-K for the year ended December 31, 2005, 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; and
- 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.