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

FORM 10-K

(Mark One)

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

OR

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from ______ to ______ Commission File Number 1-12579

OGE ENERGY CORP.

(Exact name of registrant as specified in its charter)

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

321 North Harvey
P.O. Box 321
Oklahoma City, Oklahoma 73101-0321
(Address of principal executive offices)
(Zip Code)
Registrant's telephone number, including area code: **(405) 553-3000**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock	New York Stock Exchange and Pacific Stock Exchange
Rights to Purchase Series A Preferred Stock	New York Stock Exchange and Pacific Stock Exchange

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

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

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes X No__

As of June 30, 2004, the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of shares of common stock held by non-affiliates was $2,224,093,097 based on the number of shares held by non-affiliates (87,322,069) and the reported closing market price of the common stock on the New York Stock Exchange on such date of $25.47.

As of January 31, 2005, 89,979,541 shares of common stock, par value $0.01 per share, were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The Proxy Statement for the Company's 2005 annual meeting of stockholders is incorporated by reference into Part III of this Form 10-K.

OGE ENERGY CORP.

FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2004

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PART I

Item 1. Business.

THE COMPANY

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

The Electric Utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through Oklahoma Gas and Electric Company (“OG&E”) and are subject to regulation by the Oklahoma Corporation Commission (“OCC”), the Arkansas Public Service Commission (“APSC”) and the Federal Energy Regulatory Commission (“FERC”). OG&E was incorporated in 1902 under the laws of the Oklahoma Territory and is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail gas business in 1928 and is no longer engaged in the gas distribution business.

OG&E has been and will continue to be affected by competitive changes to the utility industry. Significant changes already have occurred and additional changes are being proposed to the wholesale electric market. Although it appears unlikely in the near future that changes will occur to retail regulation in the states served by OG&E due to the significant problems faced by California in its electric deregulation efforts and other factors, significant changes are possible, which could significantly change the manner in which OG&E conducts its business. These developments at the federal and state levels are described in more detail in Note 18 of Notes to Consolidated Financial Statements.

The operations of the Natural Gas Pipeline segment are conducted through Enogex Inc. and its subsidiaries (“Enogex”) and consist of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing of natural gas. Enogex’s focus is to utilize its gathering, processing, transportation and storage capacity to execute physical, financial and service transactions to capture margins across different commodities, locations or time periods. The vast majority of Enogex’s natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. Through a 75 percent interest in the NOARK Pipeline System Limited Partnership (“NOARK”), Enogex also owns a controlling interest in and operates Ozark Gas Transmission, L.L.C. (“Ozark”), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. Enogex was previously engaged in the exploration and production of natural gas, however, this portion of Enogex’s business, along with interests in certain gas gathering and processing assets in Texas, was sold in 2002 and in the first quarter of 2003 and are reported in the Consolidated Financial Statements as discontinued operations.

The Company was incorporated in August 1995 in the State of Oklahoma and its principal executive offices are located at 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321; telephone (405) 553-3000.

Company Strategy

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

The Company’s vision is to be a regional energy company focused on its regulated utility business and natural gas pipeline business that is recognized for operational excellence and financial performance. The Company 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 normalized basis, a dividend payout ratio below 75 percent and an A- credit rating. OG&E has embarked on a Customer Savings and Reliability Plan that provides for increased investment at the utility to (i) improve reliability to meet load growth; (ii) replace aging infrastructure; and (iii) deploy newer technology to improve operational and environmental performance. Capacity payment savings from reduced cogeneration payments and fuel savings from the acquisition of a 77 percent interest in the 520 megawatt (“MW”) NRG McClain Station (the “McClain Plant”) will be utilized to mitigate the price increases associated with these investments.

At Enogex, the Company plans to continue to implement improvements to enhance long-term financial performance of its mid-continent assets through more efficient operations and effective commercial management of the assets. In addition, Enogex is seeking to diversify its gathering, processing and transportation businesses principally by expanding into other geographic areas that are complementary with the Company’s strategic capabilities. Enogex’s marketing business, which concentrates principally on origination of physical sales of natural gas, has expanded into the Gulf Coast, Rocky Mountain and East Coast markets.

The Company’s business strategy is to continue maintaining the diversified asset position of OG&E and Enogex so as to provide competitive energy products and services to customers primarily in the south central United States. The Company will focus on those products and services with limited or manageable commodity exposure. The Company intends for OG&E to continue as a vertically integrated utility engaged in the generation, transmission and distribution of electricity and to represent over time approximately 70 percent of the Company’s consolidated assets. The remainder of the Company’s consolidated assets will be in Enogex’s businesses. At December 31, 2004, OG&E and Enogex represented approximately 63 percent and 36 percent,

respectively, of the Company’s consolidated assets. The remaining one percent of the Company’s consolidated assets were primarily at the holding company. In addition to the incremental growth opportunities that Enogex provides, the Company believes that many of the risk management practices, commercial skills and market information available from Enogex provide value to all of the Company’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, the Company is applying risk management practices to all of its operations in an effort to mitigate the potential adverse effect of any future regulatory changes. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations – Executive Overview” for a further discussion.

ELECTRIC OPERATIONS — OG&E

General

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

OG&E's system control area peak demand as reported by the system dispatcher during 2004 was approximately 5,823 MWs on August 3, 2004. OG&E's load responsibility peak demand was approximately 5,460 MWs on August 3, 2004, resulting in a capacity margin of approximately 22.3 percent. As reflected in the table below and in the operating statistics on page 5, there were approximately 24.8 million megawatt-hour ("MWH") sales in 2004 as compared to approximately 25.1 million in 2003 and 24.9 million in 2002. MWH sales to OG&E's customers ("system sales") decreased approximately 0.1 percent in 2004 primarily due to milder weather during 2004. Sales to other utilities and power marketers ("off-system sales") remained flat in 2004. Variances in off-system sales are due in large part to the changing supply and demand needs on OG&E's generation system and the market for off-system sales.

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

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

(A) Sales are in million of MWHs.

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

Besides competition from other suppliers or marketers of electricity, OG&E 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 18 of Notes to Consolidated Financial Statements for a discussion of the potential impact on competition from federal and state legislation.

OKLAHOMA GAS AND ELECTRIC COMPANY
CERTAIN OPERATING STATISTICS

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

Commercial	**389.9**	372.5	346.9
Industrial	**326.7**	293.4	258.6
Public authorities	**158.5**	146.1	135.5
Sales for resale	**57.0**	57.7	48.2
Provision for refund on gas transportation and storage case	**(6.9)**	---	---
Other	**40.7**	41.9	34.9
System sales revenues	**1,577.3**	1,513.0	1,381.7
Off-system sales revenues	**0.8**	4.1	6.3
Total Electric Operating Revenues	**$ 1,578.1**	$ 1,517.1	$ 1,388.0
ACTUAL NUMBER OF ELECTRIC CUSTOMERS			
(At end of period)			
Residential	**630,736**	622,527	616,712
Commercial	**80,786**	80,265	79,768
Industrial	**9,420**	8,970	8,698
Public authorities	**14,022**	13,658	13,280
Sales for resale	**44**	50	55
Total	**735,008**	725,470	718,513
AVERAGE RESIDENTIAL CUSTOMER SALES			
Average annual revenue	**$ 975.08**	$ 970.04	$ 907.95
Average annual use (kilowatt-hour (“KWH”))	**12,630**	13,202	13,095
Average price per KWH (cents)	**$ 7.72**	$ 7.35	$ 6.93

Regulation and Rates

OG&E’s retail electric tariffs are regulated by the OCC in Oklahoma and by the APSC in Arkansas. The issuance of certain securities by OG&E is also regulated by the OCC and the APSC. OG&E’s wholesale electric tariffs, short-term borrowing authorization and accounting practices are subject to the jurisdiction of the FERC. The Secretary of the Department of Energy has jurisdiction over some of OG&E’s facilities and operations. For the year ended December 31, 2004, approximately 87 percent of OG&E’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 OG&E to reorganize into a subsidiary of the Company. The order required that, among other things, (i) the Company permit the OCC access to the books and records of the Company and its affiliates relating to transactions with OG&E; (ii) the Company employ accounting and other procedures and controls to protect against subsidization of non-utility activities by OG&E’s customers; and (iii) the Company refrain from pledging OG&E assets or income for affiliate transactions.

Regulatory Matters and Plant Acquisition

In November 2002, the OCC issued an order containing provisions of an agreed-upon settlement of OG&E’s rate case. The terms of this settlement included, among other things, a $25.0 million annual reduction in electric rates and a requirement for OG&E to acquire 400 MWs of electric generation. The rate reduction went into effect January 6, 2003 and the acquisition of a 77 percent interest in the 520 MW McClain Plant was completed on July 9, 2004. The McClain Plant, located near Newcastle, Oklahoma, is a combined cycle unit consisting of two natural-gas fired combustion turbine generators combined with a steam turbine generator. The owner of the remaining 23 percent interest in the McClain Plant is the Oklahoma Municipal Power Authority. OG&E operates the plant. The purchase price was approximately $160.0 million. OG&E temporarily funded the McClain Plant acquisition with short-term borrowings from the Company. On August 4, 2004, OG&E issued $140.0 million of long-term debt to replace these short-term borrowings. Also, on August 9, 2004, the Company made a capital contribution to OG&E of approximately $153.0 million. For additional information regarding the McClain Plant acquisition and related regulatory matters, see Note 18 of Notes to Consolidated Financial Statements.

Regulatory Assets and Liabilities

OG&E, as a regulated utility, is subject to the accounting principles prescribed by the Financial Accounting Standards Board (“FASB”) Statement of Financial Accounting Standards (“SFAS”) No. 71, “Accounting for the Effects of Certain Types of Regulation.” SFAS No. 71 provides that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management’s expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment. Excluding

recoverable take or pay gas charges, the McClain Plant operating and maintenance expenses, depreciation, ad valorem taxes and interest on debt, regulatory assets are being amortized and reflected in rates charged to customers over periods of up to 20 years.

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

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

As discussed in Note 18 of Notes to Consolidated 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 OG&E's electric generation assets and cause OG&E to discontinue the use of SFAS No. 71 with respect to its related regulatory balances. This may result in either full recovery of generation-related regulatory assets (net of related regulatory liabilities) or a non-cash, pre-tax write-off as an extraordinary charge, depending on the transition mechanisms developed by the legislature for the recovery of all or a portion of these net regulatory assets.

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

See Note 18 of Notes to Consolidated Financial Statements for a discussion of certain regulatory matters including the gas transportation and storage contract between OG&E and Enogex, security enhancements and national energy legislation.

Rate Activities and Proposals

In 2002, OG&E concluded its Oklahoma rate review proceeding before the OCC. This rate review was initiated in September 2001 by the OCC Staff and was concluded by order of the OCC on November 20, 2002. OG&E received OCC approval in the settlement of its rate case (the "Settlement Agreement") for several new customer programs and rate options, as well as modifications to existing rate structures. The Guaranteed Flat Bill ("GFB") option for residential and small general service accounts allows qualifying customers the opportunity to purchase their electricity needs at a set price for an entire year. Budget-minded customers that desire a fixed

monthly bill could benefit from the GFB option. A second tariff rate option approved in the Settlement Agreement is an offering to provide a "renewable energy" resource to OG&E's Oklahoma retail customers. This renewable energy resource is a wind power purchase program and is available as a voluntary option to all of OG&E's Oklahoma retail customers. Oklahoma's availability of wind resources makes the renewable wind power option a possible choice in meeting the renewable energy needs of our conservation-minded customers. A third new rate offering available to commercial and industrial customers is levelized demand billing. This program is beneficial for medium to large size customers with seasonally consistent demand levels who wish to reduce the variability of their monthly electric bills. The last new program being offered to OG&E's commercial and industrial customers and approved by the OCC is a new voluntary load curtailment program. This program provides customers with the opportunity to curtail on a voluntary basis when OG&E's system conditions merit curtailment action. Customers that curtail their usage will receive payment for their curtailment response. This voluntary curtailment program seeks customers that can curtail on most curtailment event days, but may not be able to curtail every time that a curtailment event is required.

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

Fuel Supply

During 2004, approximately 70 percent of the OG&E-generated energy was produced by coal units and 30 percent by natural gas units. Of the 6,141 total MW capability reflected in the table under Item 2. Properties, approximately 3,601 MWs, or 59 percent, are from natural gas generation and approximately 2,540 MWs, or 41 percent, are from coal generation. Though OG&E has a higher installed capability of generation from natural gas units, it has been more economical to generate electricity for our customers using lower priced coal. A slight decline in the percentage of coal generation in future years is expected to result from increased usage of natural gas generation required to meet growing energy needs. Over the last five years, the weighted average cost of fuel used, by type, per million British thermal unit ("MMBtu") was as follows:

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

The increase in the weighted average cost of fuel in 2004 as compared to 2003 was primarily due to increased natural gas prices and a higher amount of natural gas burned in 2004 while the increase in the weighted average cost of fuel in 2003 as compared to 2002 was primarily due to increased natural gas prices in 2003 partially offset by a lower amount of natural gas burned in 2003. The decrease in the weighted average cost of fuel in 2002 as compared to 2001 was primarily due to lower natural gas prices in 2002 partially offset by a higher amount of natural gas burned in 2002. A portion of these fuel costs is included in the base rates to customers and differs for each jurisdiction. The portion of these fuel costs that is not included in the base rates is recovered through OG&E's regulatorily approved automatic fuel adjustment clauses. See Note 1 of Notes to Consolidated Financial Statements. OG&E currently has pending before the OCC an application to recover the costs of gas transportation and storage services provided to it by Enogex pursuant to the contract between OG&E and Enogex. An adverse decision by the OCC could result in OG&E having to refund previously collected amounts. See Note 18 of Notes to Consolidated Financial Statements for a further discussion of this matter.

Coal

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

OG&E has continued its efforts to maximize the utilization of its coal units at both its Sooner and Muskogee generating plants. See "Environmental Laws and Regulations" in Note 17 of Notes to Consolidated Financial Statements for a discussion of an environmental proposal that, if implemented as proposed, could inhibit OG&E's ability to use coal as its primary boiler fuel.

Natural Gas

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

In 1993, OG&E began utilizing a natural gas storage facility that allowed OG&E 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 OG&E.

Wind

During 2003, OG&E contracted with FPL Energy for 50 MWs of electricity generated at a wind farm near Woodward, Oklahoma. After more than one year of marketing wind power to OG&E's residential and business customers, almost 9,000 have subscribed for all or part of their electricity usage. Since OG&E 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. OG&E is exploring adding another 80 MWs of wind-generated electricity to its system and, in December 2004, OG&E issued a request for proposals from companies who produce electricity from wind. OG&E expects to use the proposal responses to conduct a thorough analysis of how adding more wind will affect customers today and in the future. A decision is expected during the first or second quarter of 2005.

NATURAL GAS PIPELINE OPERATIONS – ENOGEX

Overview

The operations of the Natural Gas Pipeline segment are conducted through Enogex and consist of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing of natural gas. Enogex's focus is to utilize its gathering, processing, transportation and storage capacity to execute physical, financial and service transactions to capture margins across different commodities, locations or time periods. The vast majority of Enogex's natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. Enogex and its subsidiaries operate approximately 8,200 miles of intrastate gas gathering and transportation pipelines. Additionally, through a 75 percent interest in NOARK, Enogex also owns a controlling interest in and operates a 931 mile gas gathering and interstate transmission pipeline system of which 734 miles is comprised of a FERC regulated interstate pipeline, Ozark, that extends from southeast Oklahoma through Arkansas to southeast Missouri. Enogex was previously engaged in the exploration and production of natural gas, however, this portion of Enogex's business, along with interests in certain gas gathering and processing assets in Texas, was sold in 2002 and in the first quarter of 2003 and are reported in the Consolidated Financial Statements as discontinued operations.

Strategy

The transportation, storage and gathering assets of Enogex provide OG&E strategic access to natural gas supplies, and flexible and reliable delivery terms that are required to fuel OG&E's natural gas-fired generation facilities. Natural gas generation peaking units require the ability to quickly change their status, to meet both the peak and off-peak demands of the retail load particularly when coal units have an unscheduled outage. The gathering assets access major wellhead supply sources primarily located across Oklahoma and Arkansas, and the integrated transportation and storage assets provide the ability to regulate the receipt and delivery of natural gas to match the instantaneous needs of these generation units.

Natural gas-fired generation units contribute their highest value when they have the capability to provide "load following" service to the customer (i.e., the ability of the generation unit to regulate generation to respond to and meet the instantaneous changes in customer demand). While the physical characteristics of natural gas units are known to provide quick start-up and on-line functionality, and while their ability to efficiently provide varying levels of electric generation relative to other forms of generation is further acknowledged, their ultimate effectiveness is contingent upon having access to an integrated pipeline and storage system that can respond in a short term fashion to meet its corresponding fluctuating operational fuel requirements. The combination of these assets is critical to a generator's ability to provide reliable generation service at reasonable prices to the consumer.

Not only is Enogex providing service to OG&E, but Enogex's same assets provide firm and interruptible services to a significant portion of the other natural gas-fired generation loads in Oklahoma and other generation loads in Texas and Arkansas. Enogex understands the needs of

generators, and more importantly has the appropriately-sized pipelines, compression and integrated storage assets necessary to meet their requirements.

Through Enogex's gathering and processing assets, Enogex aggregates gas supplies for its markets and also for those markets accessible via its numerous intrastate and interstate pipeline connections. It aggressively pursues new supplies from wells drilled by producers primarily in the Anadarko and Arkoma basins. Oklahoma ranks second in the nation in onshore natural gas production and ranks second in the nation as a natural gas exporting state. The system capacity, due to its large diameter gathering pipelines and its natural gas processing plants, is capable of adapting to the varying pressure and quality requirements of mid-continent production. Enogex is able to provide low-pressure service to extend the production life of older wells as well as meeting the high-pressure requirements of new exploration. Enogex, through its processing plants, is also able to remove natural gas liquids from the wellhead gas streams, which is necessary for such gas to meet quality specifications of the downstream marketplace.

The activities described above, while central to Enogex's operations, are not its only businesses. The transportation capabilities and markets of the pipeline assets provide other business opportunities. This equally important and valuable feature of Enogex and its assets is the ability of Enogex to use its pipeline system and storage assets as a "market hub". At December 31, 2004, Enogex was connected to 15 other major pipelines at approximately 65 pipeline interconnect points providing access to markets in the western United States, the Midwest, Northeast, and Gulf Coast in addition to Oklahoma and adjoining states. Therefore, regardless of the constantly varying relationship between supply and demand, both in volume and location, Enogex's assets sit in a key geographic region of the United States, with sufficient capacity to provide cross-haul transportation and storage services to a variety of utility and industrial customers that need to access mid-continent supply for their own needs, or to suppliers from other regions seeking to provide gas to on-system markets which Enogex serves.

Enogex's marketing business is an important element in realizing the full value of its transportation and storage assets and in providing products and services that support the market hub concept. The marketing business offers the Company real-time and longer-term price discovery and valuation of energy commodities (natural gas and associated natural gas liquids) associated with the Company's assets. The marketing business also is instrumental in providing increased liquidity for these energy commodities, by focusing on developing supplies and markets that can access the Enogex systems either directly or via interconnections with intrastate and interstate pipelines. The marketing business also provides the Company the capability to provide risk management services to its customers.

The Company intends to continue to build upon the foundation of services and products that these assets can provide. In addition, the Company expects to generate additional margins by improving its ability to aggregate gas, maximize the operational capabilities of its assets and utilize commercial information available from the marketplace.

Recent Actions

Beginning in 2002, Enogex evaluated, redesigned and reorganized its internal work processes and senior management structure in order to achieve cost reductions, revenue enhancements and strategic leadership within its businesses. As a part of this process, Enogex implemented a number of steps intended to maximize the value of its assets.

Dispositions

Exploration and Production; Processing. Enogex sold all of its exploration and production assets and its interest in Belvan Corp., Belvan Limited Partnership and Todd Ranch Limited Partnership ("Belvan") in 2002 and its interest in the NuStar Joint Venture ("NuStar") in February 2003. These dispositions have been reported as discontinued operations for the years ended December 31, 2004, 2003 and 2002 in the Consolidated Financial Statements.

Processing and Compression Assets. During the fourth quarter of 2002, the Company recognized a pre-tax impairment loss of approximately $48.3 million in the Natural Gas Pipeline segment related to Enogex natural gas processing and compression assets. In the fourth quarter of 2003, the Company recognized a pre-tax impairment loss of approximately $9.2 million related to these natural gas compression assets. See Note 6 of Notes to Consolidated Financial Statements for a more detailed discussion of these impairments.

During the year ended December 31, 2004, the Company sold certain of its compression and processing assets for approximately $5.0 million and recognized an after tax gain of approximately $1.8 million related to the sale of these assets. The carrying amount of the remaining assets (that were the subject of the impairment charges in the fourth quarters of 2002 and 2003) was approximately $2.6 million and $11.9 million at December 31, 2004 and 2003, respectively. As discussed below, for any remaining assets that were the subject of the impairment charges in the fourth quarters of 2002 and 2003, the Company has either contributed the assets to the joint venture or reclassified these assets from held for sale to held and used as of December 31, 2004.

During the third quarter of 2004, Enogex entered into a joint venture arrangement with a third party and contributed certain of its natural gas compression assets (with a carrying amount of approximately $3.9 million) to the joint venture. The objective of the joint venture is to derive value from the assets by renting the natural gas compressors. Enogex Compression Company, LLC ("Enogex Compression") was created to act as the participating entity in the joint venture. Enogex Compression holds a majority ownership in the joint venture, although the actual ownership percentages may fluctuate based on the relative capital contributions of Enogex Compression and the third party member. The third party acts as the manager and conducts the daily operations of the joint venture. These assets are part of the Natural Gas Pipeline segment.

During the third quarter of 2004, the Company reclassified an asset from assets held for sale to assets held and used. This asset had a carrying amount of approximately $0.8 million at the time the asset was reclassified. In October 2004, the Company reclassified a large electric driven compressor that was previously classified as assets held for sale to assets held and used.

This compressor had a carrying amount of approximately $1.2 million at September 30, 2004. In December 2004, the Company reclassified several compressors and processing plants that were previously classified as assets held for sale to assets held and used. These assets had a carrying amount of approximately $1.6 million at December 31, 2004. See Note 6 of Notes to Consolidated Financial Statements for a more detailed discussion of these reclassifications.

Transportation and Storage. During September 2004, Enogex received notification from a customer that a transportation agreement involving four of Enogex's non-contiguous pipeline asset segments located in West Texas and used to serve the customer's power plants would be terminated effective December 31, 2004. In response to this notification, the Company recognized, during the third quarter of 2004, a pre-tax impairment loss of approximately $8.6 million in the Natural Gas Pipeline segment related to Enogex natural gas pipeline assets that were used to provide service to this customer. In December 2004, the Company received notification that all of this customers' plants in West Texas had shut down and service is no longer required. The Company is currently evaluating other commercial opportunities for these assets as well as contacting other parties that may be interested in acquiring any of these assets. See Note 6 of Notes to Consolidated Financial Statements for a more detailed discussion of this impairment.

In January 2003, Ozark recognized a gain of approximately $5.3 million and approximately $1.1 million in minority interest expense related to the sale of approximately 29 miles of transmission lines of its pipeline.

Capital Expenditures; Improvement Projects.

In 2003, Enogex began a major upgrade of its information systems that is expected to be substantially completed during the second and third quarters of 2005. Enogex believes that these upgrades will be a major step towards obtaining the data required to allow it to capture available economic opportunities on its assets, provide improved customer service and enable management to better determine the earnings potential of its various assets and service offerings.

During 2004, Enogex made improvements to the Stuart Storage Facility which reduced water encroachment in the field. During 2004, approximately $1.9 million in capital expenditures was spent on this project. Enogex does not expect any material future expenditures on this water encroachment project.

In December 2002, Enogex entered into an agreement with Colorado Interstate Gas Company regarding reservation of firm capacity on an interstate gas pipeline that was initially proposed to be in service by August 31, 2005 (the "Cheyenne Plains Pipeline"). Under the final transportation agreement, OGE Energy Resources, Inc. ("OERI") reserved 60,000 decatherms/day ("Dth/day") of capacity on the pipeline for 10 years and two months. Such reservation provides OERI access to significant additional natural gas supplies in the Rocky Mountain production basins. The Cheyenne Plains Pipeline, which began full service in February 2005, provides interstate gas transportation services in Wyoming, Colorado and Kansas with a capacity of 560,000 Dth/day. OERI pays a demand fee of approximately $7.5 million annually for this capacity.

Transportation and Storage

General. One of Enogex's primary lines of business is the transportation of natural gas, with current throughput of approximately 1.5 trillion British thermal units ("Btu") per day. Enogex delivers natural gas to most interstate and intrastate pipelines and end-users connected to its systems from the Arkoma basin of eastern Oklahoma and Arkansas, the Anadarko basin of western Oklahoma and the Panhandle of West Texas. At December 31, 2004, Enogex was connected to 15 other major pipelines at approximately 65 pipeline interconnect points. These interconnections include Panhandle Eastern Pipe Line, Southern Star Central Gas Pipeline (formerly Williams Central), Natural Gas Pipeline Company of America, Oneok Gas Transmission, Northern Natural Gas Company, ANR Pipeline, Western Farmers Electric Cooperative, CenterPoint Energy Gas Transmission Co., Black Marlin Pipeline, El Paso Natural Gas Pipeline, Kansas Pipeline and Oneok WesTex Transmission L.P., as well as connections via Enogex's Ozark system to Texas Eastern and Mississippi River Transmission. Further, Enogex is connected to various end-users including numerous electric generation facilities in Oklahoma that are fueled by natural gas. At December 31, 2004, the net property, plant and equipment balance for Enogex's transportation and storage business was approximately $714.7 million.

Enogex owns two storage facilities in Oklahoma, the Wetumka Storage Facility and the Stuart Storage Facility. These storage facilities are currently being operated at a working gas level of approximately 23 billion cubic feet ("Bcf") with an approximate withdrawal capability of 650 million cubic feet per day ("MMcfd") and similar injection capability. Enogex offers both firm and interruptible storage services to third parties, under Section 311 of the Natural Gas Policy Act ("NGPA"), under terms and conditions specified in its Statement of Operating Conditions ("SOC") for gas storage and at market-based rates to be negotiated with each customer. Both facilities are used to support Enogex's intrastate transportation and storage services for OG&E. See "Item 3. Legal Proceedings" for a discussion of the legal matters associated with the Stuart Storage Facility.

Enogex offers interruptible Section 311 transportation services as well as both firm and interruptible services to intrastate customers with a majority of transportation revenues derived from firm contracts. Enogex offers interruptible service to customers when capacity is available.

Effective January 1, 2002, Transok L.L.C. and its subsidiary entities ("Transok"), which Enogex had acquired in 1999, merged into Enogex thereby simplifying for both Enogex and its customers the administration and operation of maintaining two separate pipelines. Enogex provides firm intrastate transportation and storage services to several customers and Enogex's major customers are OG&E as well as Public Service Company of Oklahoma ("PSO"), the second largest electric utility in Oklahoma, serving the Tulsa market. Enogex provides gas transmission delivery services to all of PSO's natural gas-fired electric generation units in Oklahoma under a firm intrastate transportation contract. The current PSO contract, which has been extended to January 1, 2006, and the OG&E contract, which expires April 30, 2009, provide for a monthly demand charge plus variable transportation charges (including fuel). As part of the contract with OG&E, Enogex provides additional natural gas storage services for OG&E. Enogex has been providing natural gas storage services since August 2002 when

Enogex acquired the Stuart Storage Facility from Central Oklahoma Oil and Gas Corp. ("COOG"). During 2004, 2003 and 2002, Enogex's revenues from its firm intrastate transportation and storage contracts were approximately $95.6 million, $92.2 million and $79.5 million, respectively.

Relationship with OG&E. From its inception, Enogex has been the transporter of natural gas to OG&E's natural gas-fired generation facilities. OG&E's rates are subject to OCC jurisdiction. The OCC issued an order on November 20, 2002 which contained a provision, among other things, that OG&E would consider competitive bidding for gas transportation service to its natural gas-fired generation facilities when the contract with Enogex expired. The term of the then current contract was to expire in April 2004. Following a consideration of competitive bidding by OG&E as required by the prior order from the OCC, the contract with Enogex was amended by an agreement dated May 1, 2003 with no-notice load following requirements and a termination date of April 30, 2009. As part of the contract with OG&E, Enogex provides additional natural gas storage services for OG&E beyond the level and flexibility that was provided previously. Enogex has been providing natural gas storage services since August 2002 when Enogex acquired the Stuart Storage Facility from COOG. The amount collected from OG&E by Enogex under the current contract for transportation services was approximately $34.3 million, $33.5 million and $33.6 million, respectively, during 2004, 2003 and 2002. The amount collected from OG&E by Enogex under the current contract for storage services was approximately $15.3 million, $11.2 million and $3.3 million, respectively, during 2004, 2003 and 2002. OG&E currently has pending before the OCC an application to recover the costs of gas transportation and storage services provided to it by Enogex pursuant to the contract between OG&E and Enogex. An adverse decision by the OCC could result in OG&E having to refund previously collected amounts. See Note 18 of Notes to Consolidated Financial Statements for a further discussion of this matter.

Competition. Enogex's transportation and storage assets compete with interstate and other intrastate pipeline and storage facilities in providing transportation and storage services for natural gas. The principal elements of competition are rates, terms of services, flexibility and reliability of service.

Natural gas competes with other forms of energy available to Enogex's customers and end-users, including electricity, coal and fuel oils. The primary competitive factor is price. Changes in the availability or price of natural gas or other forms of energy as well as weather and other factors affect the demand for natural gas on the Enogex system.

Regulation. The rates charged by Enogex for transporting natural gas on behalf of an interstate natural gas pipeline company or a local distribution company served by an interstate natural gas pipeline company are subject to the jurisdiction of the FERC under Section 311 of the NGPA. Rates to provide such service must be "fair and equitable" under the NGPA and are subject to review and approval by the FERC at least once every three years. This rate review may, but will not necessarily, involve an administrative-type hearing before the FERC Staff panel and an administrative appellate review. By offering interruptible Section 311 transportation, the regulatory burden on Enogex is not appreciably increased, but does give

Enogex the opportunity to utilize any unused capacity on an interruptible basis in interstate commerce and thus increase its transportation revenues.

In December 2001, Enogex made its triennial rate filing at the FERC under Section 311 of the NGPA. Enogex also proposed a default processing fee and addressed various other issues for the combined Enogex and Transok L.L.C. pipeline systems. In May 2003, the FERC accepted a stipulation and settlement agreement and entered an order modifying Enogex's SOC with respect to priority dedicated gas.

On September 1, 2004, Enogex made a filing at the FERC to revise the SOC approved in the 2001 case, to permit, among other things, the unbundling, effective October 1, 2004, of its previously bundled gathering and transportation services. On September 30, 2004, Enogex made its triennial filing to establish rates for Section 311 service, reflecting the unbundling of the transportation and gathering services.

Numerous parties intervened in the SOC and Section 311 dockets and some parties protested one or both of the filings. The proceedings are currently in the discovery phase. A technical conference was held on January 13, 2005. For additional information regarding this matter, see Note 18 of Notes to Consolidated Financial Statements.

The Company, through Enogex, owns a 75 percent interest in Ozark. Ozark transports natural gas in interstate commerce. As a result, Ozark qualifies as a "natural gas company" under the Natural Gas Act of 1938 (the "Natural Gas Act"), and is subject to the regulatory jurisdiction of the FERC. Under the Natural Gas Act, the FERC has jurisdiction to review and authorize the proposed construction of facilities for the transportation of natural gas in interstate commerce, the rendition of service through interstate facilities, the rates charged for such service and the abandonment of such facilities or services.

The Natural Gas Act requires that the rates charged, and the terms and conditions of service observed, by interstate pipelines be "just and reasonable", and not unduly discriminatory or preferential. All rates and terms and conditions of service proposed by an interstate pipeline must be filed with the FERC, and the FERC has jurisdiction under the Natural Gas Act to determine whether proposed rates or terms and conditions meet the statutory standards. The Natural Gas Act confers upon the FERC authority to determine a jurisdictional pipeline's rates, charges and terms and conditions of service, to establish depreciation rates and to prescribe uniform systems of accounts.

The rates charged by Enogex for transporting natural gas for OG&E and other shippers within Oklahoma are not subject to FERC regulation because they are intrastate transactions. With respect to state regulation, the rates charged by Enogex for any intrastate transportation service have not been subject to direct state regulation by the OCC, which is the state agency responsible for setting rates of public utilities within Oklahoma. Even though the intrastate pipeline business of Enogex is not directly regulated by the OCC, the OCC, the APSC and the FERC (all of which approve various electric rates of OG&E) have the authority to examine the appropriateness of any transportation charges or other fees paid by OG&E to Enogex which OG&E seeks to recover from its ratepayers in its cost-of-service for electric service. See Note

18 of Notes to Consolidated Financial Statements for a discussion of OG&E's application to the OCC to approve amounts currently being charged to OG&E by Enogex for gas transportation and storage services.

Enogex's pipeline operations are subject to various Oklahoma safety and environmental and non-discriminatory transportation requirements.

Gathering and Processing

General. Natural gas gathering operations are conducted through Enogex Gas Gathering L.L.C. ("Gathering"), and natural gas processing operations are conducted through Enogex Products Corporation ("Products"). The streams of processable natural gas gathered from wells and other sources are gathered through Enogex's gas gathering systems and delivered to processing plants for the extraction of natural gas liquids. During 2004, Gathering connected 277 new producing wells, located in the Anadarko and Arkoma basins of Oklahoma and Arkansas, to its gathering systems. The Company provides connection, measurement, treating, dehydration and compression services for various types of producing wells owned by various sized producers who are active in the region. Where the quality of natural gas received dictates that removal of natural gas liquids may be in order, such gas is aggregated via the gathering system to the inlet of one or more of the Company's fleet of processing plants operated by Products. The resulting processed stream of natural gas is then delivered via the Enogex pipeline system to one or more delivery points into the web of transmission pipelines in the region. Products is one of the largest gas processors in Oklahoma, operating six natural gas processing plants with a total inlet capacity of 708 MMcfd. During 2002, Products had ownership interests in two other gas processing plants related to NuStar, which were sold in February 2003. Products has been active since 1968 in the processing of natural gas and extraction and marketing of natural gas liquids. The liquids extracted include condensate, marketable ethane, propane, butanes and natural gasoline mix. The residue gas remaining after the liquid products have been extracted consists primarily of ethane and methane. In 2004, approximately 279 million gallons of natural gas liquids were sold. Enogex continues to lease a small segment of gathering pipeline off of the Palo Duro pipeline system, referred to as the Northeast Lateral. This lease expires February 28, 2005, and, Enogex does not expect to renew the lease. At December 31, 2004, the net property, plant and equipment balance for Enogex's gathering and processing business was approximately $301.0 million.

Approximately 24 percent of the commercial grade propane processed at Products' plants is sold on the local market. The balance of propane and the other natural gas liquids produced by Products are delivered into pipeline facilities of Koch Hydrocarbon and transported to Conway, Kansas and Mont Belvieu, Texas, where they are sold under contract or on the spot market. Ethane, which may be optionally produced at all of Products' plants except one, is sold in the spot market.

During 2002, Enogex initiated steps to decrease the volatility of its earnings stream by reducing its exposure to keep-whole processing arrangements. Keep-whole processing arrangements generally require a processor of natural gas to keep its shippers whole on a Btu basis by replacing the Btu value of the liquids extracted from the well stream with natural gas at

market prices. Therefore, if natural gas prices increase and liquids prices do not increase by a corresponding amount, processing margins are negatively affected. In order to minimize the negative impact on processing margins, ethane and propane are rejected based upon then current market conditions. Exposure to these keep-whole processing arrangements was reduced through contract renegotiations and changes in the SOC provided by Enogex under the 2001 FERC Section 311 filing discussed previously. The SOC provides for a default processing fee in the event the natural gas liquids revenue less the associated fuel and shrinkage costs is negative. As a result, in months in which commodity spreads were negative, thus activating the default processing fee allowed in the SOC, the exposure to keep-whole processing arrangements has been reduced. Further, when market conditions dictated, Enogex took active steps to reduce the amount of natural gas at the plant inlet to approximately 22 percent keep-whole without the default processing fee. In addition, the Company actively monitors current and future commodity prices for opportunities to hedge its processing margin. Enogex uses forward physical sales and financial hedges to capture these spreads.

As discussed above, the Company sold all of its interest in Belvan in 2002 and its interest in NuStar in February 2003.

Competition. Enogex competes with gatherers of all types and sizes, including those affiliated with various producers, other major pipeline companies, as well as various independent gatherers. In processing and marketing natural gas liquids, Products competes against virtually all other gas processors producing and selling natural gas liquids. Competition for natural gas supply is based on efficiency and reliability of operations, reputation, access to markets and pricing. Enogex believes it will be able to continue to compete effectively.

With respect to the profitability of the natural gas processing industry generally, if the price of natural gas liquids falls without a corresponding decrease in the cost of natural gas, it may become uneconomical to extract certain natural gas liquids. This factor has had a significant adverse impact on the results of Enogex in the past, but, as discussed above, the potential adverse impact has been materially mitigated, but not entirely eliminated. In addition to the commodity pricing impact that affects the entire industry, the profitability of Products is also largely affected by the volume of natural gas processed at its plants which is highly dependent upon the volume and Btu content of natural gas gathered. Generally, if the volume of natural gas gathered increases, then the volume of natural gas liquids extracted by Products should also increase.

Marketing

General. Enogex's commodity sales and services related to natural gas are conducted primarily through its subsidiary, OERI.

OERI is engaged in the business of natural gas marketing. OERI provides marketing services to Enogex for natural gas volumes purchased at the wellhead from customers. As a service to the producers on the Enogex system, Enogex may agree to purchase the gas at the wellhead in conjunction with gathering their gas for transportation to other markets.

OERI also purchases and sells natural gas pursuant to contracts with Enogex and Products relating to Enogex's gathering, processing and storage assets. At December 31, 2004, the net property, plant and equipment balance for Enogex's marketing business was approximately $0.7 million.

OERI focuses on serving customers along the natural gas value chain, from producers to end-users, by purchasing natural gas from suppliers and reselling to pipelines, local distribution companies and end-users, including the electric generation sector.

The geographic scope of marketing efforts has been focused largely in the mid-continent area of the United States. These markets are natural extensions of OERI's business on the Enogex system. OERI contracts for pipeline capacity with Enogex and other pipelines to access multiple interconnections with the interstate pipeline system network that moves natural gas from the production basins primarily in the south central United States to the major consumption areas in Chicago, New York and other north central and mid-Atlantic regions of the United States. Also, Enogex's marketing business has expanded into the Gulf Coast, Rocky Mountain and East Coast markets to diversify its business.

OERI participates in both intermediate-term markets (less than three years) and short-term "spot" markets for natural gas. Although OERI continues to increase its focus on intermediate-term sales, short-term sales of natural gas are expected to continue to play a critical role in the overall strategy because they provide an important source of market intelligence as well as an important portfolio balancing function. In 2004, OERI's average daily sales volumes grew from approximately 1.3 Bcf in 2003 to 1.8 Bcf of natural gas.

OERI's risk management skills afford its customers the opportunity to tailor the risk profile and composition of their natural gas portfolio. The Company follows a policy of hedging price risk on gas purchases or sales contracts entered into by the marketing group by buying and selling natural gas futures contracts on the New York Mercantile Exchange futures exchange and other derivatives in the over-the-counter market, subject to daily and monthly trading stop loss limits of $2.5 million in accordance with corporate policies.

Competition. OERI competes in marketing natural gas with major integrated oil companies, marketing affiliates of major interstate and intrastate pipelines, national and local natural gas brokers and marketers and distributors for natural gas supplies. Competition for natural gas supplies is based primarily on reputation, credit support, the availability of gathering and transportation to high-demand markets and the ability to obtain a satisfactory price for the producer's natural gas. Competition for sales to customers is based primarily upon reliability, services offered and the price of delivered natural gas.

For the year ended December 31, 2004, approximately 61.7 percent of OERI's service volumes were with electric utilities, local gas distribution companies, pipelines and producers. The remaining 38.3 percent of service volumes were to marketers, municipals, cooperatives and industrials. At December 31, 2004, approximately 80.6 percent of the payment exposure was to companies having investment grade ratings with Standard & Poor's Ratings Services ("Standard & Poor's") and approximately 0.3 percent having less than investment grade ratings. The

remaining 19.1 percent of OERI's exposure is with privately held companies, municipals or cooperatives that were not rated by Standard & Poor's. OERI applies internal credit analyses and policies to these non-rated companies.

Exploration and Production

The Company sold all of its exploration and production assets in 2002. These operations have been reported as discontinued operations in the Consolidated Financial Statements. The exploration and production activities were conducted through Enogex Exploration Corporation, which was formed in 1988 primarily to engage in the development and production of oil and natural gas. Exploration focused its drilling activity in Michigan and Oklahoma. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations – Enogex – Discontinued Operations" 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 OG&E's electric utility business and replacing or expanding existing facilities (including technology) at Enogex. Other working capital requirements are primarily related to maturing debt, operating lease obligations, hedging activities, natural gas storage 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 (through a combination of bank borrowings and commercial paper) and permanent financings. See "Item 7. Management's Discussion and Analysis of Financial Conditions and Results of Operations – Liquidity and Capital Requirements" for a discussion of the Company's capital requirements.

Capital Expenditures

The Company's current 2005 to 2007 construction program includes continued investment in system and transmission upgrades that is part of the Company's Customer Savings and Reliability Plan. OG&E has approximately 430 MWs of contracts with qualified cogeneration facilities and small power production producers' ("QF contracts") that will expire at the end of 2007, unless extended by OG&E. In addition, effective September 1, 2004, OG&E entered into a new 15-year power sales agreement for 120 MWs with PowerSmith Cogeneration Project, L.P. ("PowerSmith"). OG&E 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, OG&E 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, OG&E will also assess the feasibility of constructing additional base load coal-fired units. See "Item 7. Management's Discussion and Analysis of Financial

Conditions and Results of Operations – Liquidity and Capital Requirements" for a discussion of the Company's capital expenditures.

Pension and Postretirement Benefit Plans

During 2004 and 2003, the Company made contributions of approximately $69.0 million and $50.0 million, respectively, to ensure that the pension plan maintains an adequate funded status. During 2005, the Company plans to contribute approximately $37.4 million to the pension plan. 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 pension and postretirement benefit plans.

Future Sources of Financing

Management expects that internally generated funds, proceeds from the sales of common stock pursuant to the Company's Automatic Dividend Reinvestment and Stock Purchase Plan and long and short-term debt will be adequate over the next three years to meet anticipated capital expenditures, operating needs, payment of dividends and maturities of long-term debt. As discussed below, the Company utilizes short-term borrowings (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 "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Requirements – Future Sources of Financing" for a table showing the Company's lines of credit in place and available cash at January 31, 2005. At January 31, 2005, the Company's short-term borrowings consisted of commercial paper.

ENVIRONMENTAL MATTERS

Approximately $7.0 million of the Company's capital expenditures budgeted for 2005 are to comply with environmental laws and regulations. The Company's management believes that all of its operations are in substantial compliance with present federal, state and local environmental standards. It is estimated that the Company's total expenditures for capital, operating, maintenance and other costs to preserve and enhance environmental quality will be approximately $57.8 million during 2005, as compared to approximately $57.1 million in 2004. The Company continues to evaluate its environmental management systems to ensure compliance with existing and proposed environmental legislation and regulations and to better position itself in a competitive market. See Note 17 of Notes to Consolidated Financial Statements for a discussion of environmental matters, including the impact of existing and proposed environmental legislation and regulations.

EMPLOYEES

The Company and its subsidiaries had 3,012 employees at December 31, 2004.

ACCESS TO SECURITIES AND EXCHANGE COMMISSION FILINGS

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

Item 2. Properties.

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

Station & Unit		Year Installed	Unit Design Type	Fuel Capability	Unit Run Type	2004 Capacity Factor (A)	Unit Capability (MWs)	Station Capability (MWs)
Seminole	1	1971	Steam-Turbine	Gas	Base Load	25.5%	506.0	
	1GT	1971	Combustion-Turbine	Gas	Peaking	0.01%(B)	15.4	
	2	1973	Steam-Turbine	Gas	Base Load	28.1%	507.6	
	3	1975	Steam-Turbine	Gas/Oil	Base Load	25.4%	516.8	1,545.8
Muskogee	3	1956	Steam-Turbine	Gas	Base Load	6.6%	166.0	
	4	1977	Steam-Turbine	Coal	Base Load	77.0%	500.5	
	5	1978	Steam-Turbine	Coal	Base Load	70.4%	521.6	
	6	1984	Steam-Turbine	Coal	Base Load	63.4%	499.0	1,687.1
Sooner	1	1979	Steam-Turbine	Coal	Base Load	80.8%	505.2	
	2	1980	Steam-Turbine	Coal	Base Load	64.8%	513.8	1,019.0
Horseshoe Lake	6	1958	Steam-Turbine	Gas/Oil	Base Load	17.8%	168.5	
	7	1963	Combined Cycle	Gas/Oil	Base Load	17.4%	234.0	
	8	1969	Steam-Turbine	Gas	Base Load	7.8%	380.5	
	9	2000	Combustion-Turbine	Gas	Peaking	9.1% (B)	45.5	
	10	2000	Combustion-Turbine	Gas	Peaking	9.1% (B)	45.5	874.0
Mustang	1	1950	Steam-Turbine	Gas	Peaking	0.6% (B)	53.0	
	2	1951	Steam-Turbine	Gas	Peaking	0.6% (B)	53.0	
	3	1955	Steam-Turbine	Gas	Base Load	19.0%	117.5	
	4	1959	Steam-Turbine	Gas	Base Load	17.6%	250.0	
	5	1971	Combustion-Turbine	Gas/Jet Fuel	Peaking	0.6% (B)	60.0	533.5
Conoco	1	1991	Combustion-Turbine	Gas	Base Load	66.5%	31.5	
	2	1991	Combustion-Turbine	Gas	Base Load	69.8%	31.0	62.5
Enid	1	1965	Combustion-Turbine	Gas	Peaking	--- (C)	---	
	2	1965	Combustion-Turbine	Gas	Peaking	--- (C)	---	
	3	1965	Combustion-Turbine	Gas	Peaking	--- (C)	---	
	4	1965	Combustion-Turbine	Gas	Peaking	--- (C)	---	---
Woodward	1	1963	Combustion-Turbine	Gas	Peaking	0.1% (B)	12.0	12.0
McClain (D)	1	2001	Combined Cycle	Gas	Base Load	59.8%	406.8	406.8
Total Generating Capability (all stations)								6,140.7

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

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

At December 31, 2004, Enogex and its subsidiaries owned: (i) approximately 8,200 miles of intrastate gas gathering and transportation pipelines in Oklahoma and Texas; (ii) a 75 percent interest in NOARK, which consists of 931 miles of interstate gas gathering and transportation pipelines, located in eastern Oklahoma and Arkansas; (iii) two natural gas storage fields in Oklahoma operating at a working gas level of approximately 23 Bcf with an approximate withdrawal capability of 650 MMcfd and similar injection capability; and (iv) six operating natural gas processing plants with a total inlet capacity of 708 MMcfd, all located in Oklahoma. The following table sets forth information with respect to Enogex's natural gas processing plants:

Processing Plant	Year Installed	Type of Plant	Fuel Capability	2004 Inlet Volumes (MMcfd)	2004 Inlet Capacity (MMcfd)
Calumet	1969	Lean Oil	Gas	110	250

Cox City	1994	Cryogenic Refrigeration	Gas	139	150
Harrah	1994	Cryogenic Refrigeration	Gas	23	38
Thomas	1981	Cryogenic Refrigeration	Gas	78	150
Canute	1996	Cryogenic Refrigeration	Gas	55	60
Wetumka	1983	Cryogenic Refrigeration	Gas	32	60
				437	708

During the three years ended December 31, 2004, the Company's gross property, plant and equipment additions were approximately $839.9 million and gross retirements were approximately $250.0 million. These additions were provided by internally generated funds from operating cash flows, short-term borrowings (through a combination of bank borrowings and commercial paper) and permanent financings. The additions during this three-year period amounted to approximately 13.8 percent of total property, plant and equipment at December 31, 2004.

Item 3. Legal Proceedings.

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies. Management consults with counsel and other appropriate experts to assess the claim. If in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. Except as set forth below and in Notes 17 and 18 of Notes to Consolidated Financial Statements, management, after consultation with legal counsel, does not anticipate that liabilities arising out of currently pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

1. The City of Enid, Oklahoma ("Enid") through its City Council, notified OG&E of its intent to purchase OG&E's electric distribution facilities for Enid and to terminate OG&E'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 OG&E 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, OG&E 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 OG&E the option the city held to acquire OG&E'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) OG&E's support of the Enid Citizens' Against the Government Takeover was improper; (v) OG&E has violated the favored nations clause of the existing franchise; and (vi) the City of Enid and OG&E 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 OG&E's property to be transferred to OG&E for inadequate consideration. Plaintiffs demanded judgment for treble the value of the property allegedly wrongfully transferred to OG&E. On October 28, 1997, another resident filed a similar lawsuit against OG&E, 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, OG&E filed a Motion to Dismiss Case No. CJ-97-829-01 for failure to state claims upon which relief may be granted and no action has been taken on this motion for seven years. While the Company cannot predict the precise outcome of this proceeding, the Company believes at the present time that this lawsuit is without merit and intends to vigorously defend this case.

2. United States of America ex rel., Jack J. Grynberg v. Enogex Inc., Enogex Services Corporation and OG&E. (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 Btu content) purchased from federal and Indian lands which have resulted in the under-reporting and underpayment of gas royalties owed to the Federal Government; (ii) certain provisions generally found in gas purchase contracts are improper; (iii) transactions by affiliated companies are not arms-length; (iv) excess processing cost deduction; and (v) failure to account for production separated out as a result of gas processing. Grynberg seeks the following damages: (a) additional royalties which he claims should have been paid to the Federal Government, some percentage of which Grynberg, as relator, may be entitled to recover; (b) treble damages; (c) civil penalties; (d) an order requiring defendants to measure the way Grynberg contends is the better way to do so; and (e) interest, costs and attorneys' fees.

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

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

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

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

3. *Will Price (Price I)* – On September 24, 1999, various subsidiaries of the Company 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, OG&E and Enogex Inc. were omitted from the case. Two subsidiaries of Enogex remain as defendants. The Plaintiffs' amended petition alleges that approximately 60 defendants, including two Enogex subsidiaries, have improperly measured natural gas. The amended petition reduces the claims to: (1) mismeasurement of volume only; (2) conspiracy, unjust enrichment and accounting; (3) a putative Plaintiffs' class of only royalty owners; and (4) gas measured in three specific states. Discovery on class certification is proceeding. A hearing on class certification issues is set for April 1, 2005.

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

4. *Will Price (Price II)* – On May 12, 2003, the Plaintiffs (same as those in Price I above) filed a new class action petition (Price II) in the District Court of Stevens County, Kansas, relating to wrongful Btu analysis against natural gas pipeline owners and operators, naming the same defendants as in the amended petition of the Price I case. Two Enogex subsidiaries were served on August 4, 2003. The Plaintiffs seek to represent a class of only royalty owners either from whom the defendants had purchased natural gas or measured natural gas since January 1, 1974 to the present. The class action petition alleges improper analysis of gas heating content. In all other respects, the Price II petition appears to be the same as the amended petition in Price I. Discovery on class certification is proceeding. A hearing on class certification issues is set for April 1, 2005.

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

5. A Notice of Enforcement Action ("NOE") by the Texas Natural Resource Conservation Commission (now known as the Texas Commission on Environmental Quality ("TCEQ")) was issued to Enogex Products Corporation, a subsidiary of Enogex, by letter dated July 26, 2002. The NOE relates to the operation of a sulfur recovery unit owned and operated by Belvan at its Crockett County, Texas natural gas processing facility. Products sold its interest in Belvan in March 2002. The TCEQ's proposed fine was approximately $0.1 million. Products has requested the TCEQ to issue the NOE in the permitted entity's name and is waiting for this correction from the TCEQ. Pursuant to the Agreement of Sale and Purchase with the purchaser, Products' may retain some liability for penalties that Belvan might incur from the NOE not to exceed approximately $0.1 million. This amount is fully reserved on Products' books.

6. In 1998, Enogex entered into a Storage Lease Agreement (the "Agreement") with COOG. Under the Agreement, COOG agreed to make certain enhancements to the Stuart Storage Facility to increase capacity and deliverability of the facility. In 1999 a dispute arose as to whether the natural gas deliverability for the Stuart Storage Facility was being provided by

COOG and these issues were submitted to arbitration in October and November 2001. In July 2002, the Oklahoma District Court affirmed the arbitration award and entered judgment against COOG and in favor of Enogex in the amount of approximately $23.3 million (the "Judgment").

On July 24, 2002, Enogex exercised the asset purchase option provided in the Agreement and title to the Stuart Storage Facility was transferred to Enogex on October 24, 2002, effective August 9, 2002 (the date COOG turned over operations of the facility to Enogex). As part of the Agreement, the Company agreed in 1998 to make up to a $12 million secured loan to Natural Gas Storage Corporation ("NGSC"), an affiliate of COOG (the "NGSC Loan"). NGSC failed and refused to repay the NGSC Loan.

On August 12, 2002, the Company received a petition in a legal proceeding filed by COOG and NGSC against the Company and Enogex in Texas. COOG and NGSC stated a claim for declaratory judgment asserting, among other things, that NGSC is not obligated to make payments on the NGSC Loan based on various theories and, that: (1) the Company was obligated to demand Enogex make the requisite payments to the Company; (2) the Company is liable to NGSC for failing to demand the requisite payments from Enogex, or alternatively, NGSC is entitled to a reduction in the amount it owes to the Company; (3) Enogex was and is obligated to make the payments to the Company until the indebtedness of NGSC to the Company is reduced to zero; (4) Enogex is not entitled to set off the Judgment against the lease payments that it originally owed to COOG and now owes to the Company; (5) no event of default has occurred; and (6) under the Agreement, the only remedy Enogex had or has if the Stuart Storage Facility did not perform was to seek a modification of the lease payments based upon COOG's expert's analysis of the performance of the Stuart Storage Facility. COOG and NGSC have also stated claims for breach of contract relating to the same allegations in its claim for declaratory relief and include claims for attorneys' fees.

The Company objected to being sued in Texas because the Texas Court does not have proper jurisdiction over the Company. In 2002, Enogex responded to the allegations, asserting, among other things, that the disputed issues have already been properly determined by the Arbitration Panel and the Oklahoma Court and, therefore, this action is improper.

By order dated June 19, 2003, the Texas Court granted Enogex's request for arbitration and ordered COOG, NGSC and Enogex to arbitration. The parties participated in the Oklahoma County arbitration in May 2004 and the arbitration panel rendered a decision in the Company's favor for approximately $5.0 million related to the outstanding NGSC Loan on July 15, 2004 and this judgment is final.

In 2003, the Company and Enogex brought separate complaints against the individual shareholders of COOG and NGSC – Enogex Inc. v John C. Thrash, John F. Thrash and Robert R. Voorhees, Jr., Case No. CIV-03-0388-L; and OGE Energy Corp. and Enogex Inc. v John C. Thrash, John F. Thrash and Robert R. Voorhees, Jr., Case No. CIV 03-0389-L – both filed in the Western District of Oklahoma Federal Court. The Company and Enogex each stated claims for (1) fraudulent transfer; (2) imposition of an equitable trust; and (3) breach of fiduciary duty. A jury trial was held from October 12 – 26, 2004. The case was submitted to the jury on October 25, 2004 and the jury ruled in favor of the Company and Enogex for approximately $6.6 million.

The individual defendants have filed a motion for new trial, which is currently pending before the Court. Also in the Texas case, on October 4, 2004, the plaintiffs filed a first amended petition seeking: (i) declaratory judgment based on collusion to impair collateral; (ii) gross negligence; and (iii) declaratory judgment and confirmation of certain aspects of the arbitration award. The plaintiffs have added a request for punitive damages. A motion to strike the amended petition or alternatively refer any remaining issues to arbitration under the parties' agreement has been filed by Enogex and the Company. The plaintiffs filed a motion to dismiss Enogex from the suit which the court granted by order dated January 26, 2005. Enogex has objected to this ruling and has requested reconsideration of the court's ruling to properly reserve the previous rulings in this matter. A determination relating to the jurisdiction by the Texas court of the Company is pending before the court.

The Company intends to continue to vigorously pursue its rights in conjunction with the remaining amounts owed under the judgments, plus interest.

7. Farmland Industries, Inc. ("Farmland") voluntarily filed for Chapter 11 bankruptcy protection from creditors in 2002. Enogex provided gas transportation and supply services to Farmland, and was an unsecured creditor of Farmland. Enogex filed its proof of claim in 2003 for approximately $5.4 million. In April 2003, Enogex negotiated a settlement and received the agreed settlement amount of approximately $2.7 million during 2003 and 2004.

In addition, Farmland filed a dismissal of its preference claim it had asserted against Enogex. On July 8, 2004, Enogex received a distribution check from Farmland for approximately $0.5 million. The remainder of the settlement amount (approximately $0.3 million) was paid on July 30, 2004. These amounts are included in the $2.7 million discussed above. This case is now closed.

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

In the Grady case, the plaintiff alleged that OG&E breached the terms of several gas purchase contracts in amounts set forth in the contracts. In 2001, the district court rendered a verdict against OG&E in the amount of approximately $8.0 million, including pre-judgment interest and attorneys' fees. OG&E filed an appeal and on May 18, 2004, the Court of Appeals issued an opinion reversing the judgment and remanding for a new trial. The appellate court found that the trial court committed reversible error in rejecting a portion of OG&E's

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

9. National Steel Corporation ("National Steel") voluntarily filed for Chapter 11 bankruptcy protection from creditors in 2002. OERI provided gas supply services to National Steel and was an unsecured creditor of National Steel. OERI filed its proof of claim on August 14, 2002 for approximately $0.9 million. This amount was originally fully reserved on OERI's books; however, the receivable was subsequently determined to be uncollectible by OERI, and the reserved amount was reduced to zero. In March 2004, National Steel filed an adversary proceeding in the pending bankruptcy against OERI seeking the refund and return of payments made by National Steel to OERI during the 90 days preceding its bankruptcy filing totaling approximately $2.7 million. A settlement of the pending bankruptcy issues was reached in October 2004 between the parties wherein OERI agreed to not pursue its claim in the bankruptcy (approximately a $12,000 claim based on the filed bankruptcy plan) in exchange for National Steel dismissing the pending preference claim. The Company now considers this case to be closed.

10. OG&E vs. Terra Tech, LLC, District Court of Oklahoma County, State of Oklahoma. Case No. CJ-2004-149. OG&E 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 OG&E. Defendant Terra Tech contends that OG&E's actions constituted a breach of oral

contract and failure to pay for work performed in an amount in excess of $10,000. Defendant Terra Tech also seeks attorney fees. OG&E believes that recovery on the counterclaim by Terra Tech, if any, would be less than OG&E's recovery against Terra Tech. Discovery has been served on the defendant and there have been no scheduling deadlines or trial date yet.

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

None.

Executive Officers of the Registrant.

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

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

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

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

Name	Business Experience	
Steven E. Moore	2000 - Present:	Chairman of the Board, President and Chief Executive Officer
Peter B. Delaney	2004 - Present:	Executive Vice President and Chief Operating Officer
	2002 - 2004:	Executive Vice President, Finance and Strategic Planning - OGE Energy Corp. and Chief Executive Officer - Enogex Inc.
	2001 - 2002:	Principal, PD Energy Advisors (consulting firm)
	2000 - 2001:	Managing Director, UBS Warburg (investment banking firm)
James R. Hatfield	2000 - Present:	Senior Vice President and Chief Financial Officer
	2000:	Senior Vice President, Chief Financial Officer and Treasurer
Jack T. Coffman	2000 - Present:	Senior Vice President - Power Supply - OG&E
Steven R. Gerdes	2003 - Present:	Vice President - Utility Operations - OG&E
	2000 - 2003:	Vice President - Shared Services
Melvin H. Perkins, Jr.	2004 - Present:	Vice President - Transmission - OG&E
	2002 - 2003:	Director - Transmission Policy - OG&E
	2000 - 2002:	Manager, Power Delivery Operations - OG&E

Michael G. Davis	2004 - Present:	Vice President - Business Process
	2002 - 2003:	Vice President - Process Management - OG&E
	2000 - 2002:	Vice President - Marketing and Customer Care - OG&E

Name	Business Experience	
Donald R. Rowlett	2000 - Present:	Vice President and Controller
Deborah S. Fleming	2003 - Present:	Treasurer
	2000 - 2003:	Assistant Treasurer - Williams Cos. Inc.
	2000:	Director of Corporate Finance - Williams Cos. Inc. (energy company)
Gary D. Huneryager	2002 - Present:	Internal Audit Officer
	2001 - 2002:	Assistant Internal Audit Officer
	2000 - 2001:	Service Line Director (Business Process Outsourcing) - Arthur Andersen LLP
Carla D. Brockman	2002 - Present:	Corporate Secretary
	2002:	Assistant Corporate Secretary
	2000 - 2002:	Client Manager - Strategic Planning
Danny P. Harris	2001 - Present:	Vice President and Chief Operating Officer - Enogex Inc.
	2000 - 2001:	Director, Strategic Development - Enogex Inc.
	2000:	Manager, System Control - Enogex Inc.
Jerry A. Peace	2004 - Present:	Chief Risk and Compliance Officer
	2002 - 2004:	Chief Risk Officer
	2001 - 2002:	Director, Options Trading - Enogex Inc.
	2000 - 2001:	Director, Structured Services - Enogex Inc.

PART II

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

The Company’s Common Stock is listed for trading on the New York and Pacific Stock Exchanges under the ticker symbol “OGE.” Quotes may be obtained in daily newspapers where the common stock is listed as “OGE Engy” in the New York Stock Exchange listing table. The following table gives information with respect to price ranges, as reported in *The Wall Street Journal* as New York Stock Exchange Composite Transactions, and dividends paid for the periods shown.

2003	Dividend Paid	Price High	Price Low
First Quarter	$ 0.3325	$ 19.37	$ 15.99
Second Quarter	0.3325	22.25	17.36
Third Quarter	0.3325	22.75	19.50
Fourth Quarter	0.3325	24.34	21.96

2004	**Dividend Paid**	**Price High**	**Price Low**
First Quarter	**$ 0.3325**	**$ 26.70**	**$ 23.03**

Second Quarter	**0.3325**	**26.80**	**22.85**
Third Quarter	**0.3325**	**26.48**	**24.10**
Fourth Quarter	**0.3325**	**26.95**	**25.17**

2005	Dividend Paid	Price High	Price Low
First Quarter (through January 31)	$ 0.3325	$ 26.67	$ 25.15

The number of record holders of the Company's Common Stock at January 31, 2005, was 30,965. The book value of the Company's Common Stock at January 31, 2005, was $14.35.

Dividend Restrictions

Before the Company can pay any dividends on its common stock, the holders of any of its preferred stock that may be outstanding are entitled to receive their dividends at the respective rates as may be provided for the shares of their series. Currently, there are no shares of preferred stock of the Company outstanding. Because the Company is a holding company and conducts all

of its operations through its subsidiaries, the Company's cash flow and ability to pay dividends will be dependent on the earnings and cash flows of its subsidiaries and the distribution or other payment of those earnings to the Company in the form of dividends, or in the form of repayments of loans or advances to it. The Company expects to derive principally all of the funds required by it to enable it to pay dividends on its common stock from dividends paid by OG&E, on OG&E's common stock, and from Enogex, on Enogex's common stock. The Company's ability to receive dividends on OG&E's common stock is subject to the prior rights of the holders of any OG&E preferred stock that may be outstanding and the covenants of OG&E's certificate of incorporation and its debt instruments limiting the ability of OG&E to pay dividends.

Under OG&E's certificate of incorporation, if any shares of its preferred stock are outstanding, dividends (other than dividends payable in common stock), distributions or acquisitions of OG&E common stock:

- may not exceed 50 percent of net income for a prior 12-month period, after deducting dividends on any preferred stock during the period, if the sum of the capital represented by the common stock, premiums on capital stock (restricted to premiums on common stock only by SEC orders), and surplus accounts is less than 20 percent of capitalization;

- may not exceed 75 percent of net income for such 12-month period, as adjusted if this capitalization ratio is 20 percent or more, but less than 25 percent; and

- if this capitalization ratio exceeds 25 percent, dividends, distributions or acquisitions may not reduce the ratio to less than 25 percent except to the extent permitted by the provisions described in the above two bullet points.

Currently, no shares of OG&E preferred stock are outstanding and no portion of the retained earnings of OG&E is presently restricted by this provision.

Issuer Purchases of Equity Securities

Except as noted below, the shares indicated below represent shares of Company common stock purchased on the open market by the trustee for the Company's Stock Ownership and Retirement Savings Plan and reflect shares purchased with employee contributions as well as the portion attributable to the Company's matching contributions.

Period	Total Number of Shares Purchased	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plan	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plan
1/1/04 - 1/31/04	105,900	$ 24.06	N/A	N/A
2/1/04 - 2/29/04	16,400	$ 24.56	N/A	N/A
3/1/04 - 3/31/04	16,900	$ 26.01	N/A	N/A
4/1/04 - 4/30/04	138,900	$ 24.55	N/A	N/A
5/1/04 - 5/31/04	16,600	$ 24.24	N/A	N/A
6/1/04 - 6/30/04*	51,144	$ 24.39	N/A	N/A
7/1/04 - 7/31/04	90,000	$ 24.50	N/A	N/A
8/1/04 - 8/31/04	34,800	$ 24.77	N/A	N/A
9/1/04 - 9/30/04	26,700	$ 25.57	N/A	N/A

10/1/04 - 10/31/04	80,600	$ 25.47	N/A	N/A
11/1/04 - 11/30/04	54,800	$ 25.99	N/A	N/A
12/1/04 - 12/31/04	57,600	$ 26.26	N/A	N/A

* This month reflects the following transactions: (i) the surrender to the Company of 7,244 shares of common stock at an average price of $25.14 per share to satisfy tax withholding obligations in connection with the vesting of restricted stock issued to employees; and (ii) the purchase of 43,900 shares of common stock at an average price of $24.27 per share relating to the Company's Stock Ownership and Retirement Savings Plan.
N/A - not applicable

Item 6. Selected Financial Data.

HISTORICAL DATA

	2004	2003	2002	2001	2000
SELECTED FINANCIAL DATA *(In millions, except per share data)*					
Operating revenues	**$4,926.6**	$3,779.0	$3,023.9	$3,064.4	$3,184.4
Cost of goods sold	**3,962.7**	2,846.0	2,120.3	2,185.6	2,275.3
Gross margin on revenues	**963.9**	933.0	903.6	878.8	909.1
Other operating expenses	**646.4**	626.1	667.9	607.9	574.5
Operating income	**317.5**	306.9	235.7	270.9	334.6
Other income	**12.1**	8.1	3.7	3.1	4.2
Other expense	**5.5**	9.0	4.7	4.2	3.6
Net interest expense	**90.9**	96.7	109.1	123.0	129.4
Income tax expense	**80.2**	73.7	44.6	52.9	72.0
Income from continuing operations	**153.0**	135.6	81.0	93.9	133.8
Income (loss) from discontinued operations, net of tax	**0.5**	(0.4)	9.8	6.7	13.2
Cumulative effect on prior years of change in accounting principle, net of tax of $3.4	---	(5.4)	---	---	---
Net income	**$ 153.5**	$ 129.8	$ 90.8	$ 100.6	$ 147.0
Basic earnings (loss) per average common share					
Income from continuing operations	**$ 1.73**	$ 1.66	$ 1.04	$ 1.20	$ 1.72
Income from discontinued operations, net of tax	**0.01**	---	0.12	0.09	0.17
Loss from cumulative effect of accounting change, net of tax	---	(0.07)	---	---	---
Net income	**$ 1.74**	$ 1.59	$ 1.16	$ 1.29	$ 1.89
Diluted earnings (loss) per average common share					
Income from continuing operations	**$ 1.72**	$ 1.65	$ 1.04	$ 1.20	$ 1.72
Income from discontinued operations, net of tax	**0.01**	---	0.12	0.09	0.17
Loss from cumulative effect of accounting change, net of tax	---	(0.07)	---	---	---
Net income	**$ 1.73**	$ 1.58	$ 1.16	$ 1.29	$ 1.89
Dividends declared per share	**$ 1.33**	$ 1.33	$ 1.33	$ 1.33	$ 1.33

HISTORICAL DATA (Continued)

	2004	2003	2002	2001	2000
SELECTED FINANCIAL DATA *(In millions, except per share data)*					

Long-term debt	**$1,424.1**	$1,436.1	$1,501.9	$1,526.3	$1,648.5
Total assets	**$4,870.3**	$4,584.7	$4,264.9	$4,118.0	$4,444.6
CAPITALIZATION RATIOS (A)					
Stockholders' equity	**47.44%**	45.56%	39.58%	40.54%	39.23%
Long-term debt	**52.56%**	54.44%	60.42%	59.46%	60.77%
RATIO OF EARNINGS TO FIXED CHARGES (B)					
Ratio of earnings to fixed charges	**3.29**	3.06	2.08	2.10	2.45

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

(B) For purposes of computing the ratio of earnings to fixed charges, (1) earnings consist of pre-tax income from continuing operations plus fixed charges, less allowance for borrowed funds used during construction and minority interest expense; 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

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

The Electric Utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through Oklahoma Gas and Electric Company ("OG&E") and are subject to regulation by the Oklahoma Corporation Commission ("OCC"), the Arkansas Public Service Commission ("APSC") and the Federal Energy Regulatory Commission ("FERC"). OG&E was incorporated in 1902 under the laws of the Oklahoma Territory and is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail gas business in 1928 and is no longer engaged in the gas distribution business.

The operations of the Natural Gas Pipeline segment are conducted through Enogex Inc. and its subsidiaries ("Enogex") and consist of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing of natural gas. Enogex's focus is to utilize its gathering, processing, transportation and storage capacity to execute physical, financial and service transactions to capture margins across different commodities, locations or time periods. The vast majority of Enogex's natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. Through a 75 percent interest in the NOARK Pipeline System Limited Partnership ("NOARK"), Enogex also owns a controlling interest in and operates Ozark Gas Transmission, L.L.C. ("Ozark"), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. Enogex was previously engaged in the exploration and production of natural gas, however, this portion of Enogex's business, along with interests in certain gas gathering and processing assets in Texas, was sold in 2002 and in the first quarter of 2003 and are reported in the Consolidated Financial Statements as discontinued operations.

Executive Overview

In early 2002, the Company completed a review of its business strategy that was largely driven by the anticipated deregulation of the retail electric markets in Oklahoma and Arkansas. Due to a variety of factors, the Company recognized that immediate deregulation of the retail electric markets in Oklahoma and Arkansas was very unlikely and revised its business strategy. In the summer of 2004, the Company again reviewed its business strategy in light of significant changing market and regulatory trends such as the over supply of electric generation, the evolution of electric transmission markets and rules, the natural gas supply forecast, the sustained increase of natural gas commodity prices and the anticipated emergence of liquefied

natural gas. The Company concluded that its existing business strategy of utilizing a diversified asset position was the proper course.

During 2004, the Company had several significant accomplishments including the completion of the acquisition of a 77 percent interest in the 520 megawatt ("MW") NRG McClain Station (the "McClain Plant") in July 2004, the completion of two revolving credit agreements totaling $550 million for the Company and OG&E in October 2004, improved financial performance at Enogex, improved financial flexibility associated with the reduction of the long-term debt balance at Enogex, such that Enogex began to contribute to funding the Company's dividend which has been funded solely by OG&E in the past. Looking at 2005, OG&E expects to file a rate case during the second quarter of 2005 to recover, among other things, its investment in, and the operating expenses of, the McClain Plant and expects new approved rates to be in effect by January 2006. Also, during 2005, OG&E will work to advance its Customer Savings and Reliability Plan which provides for increased investment at the utility to improve reliability and meet load growth, replace infrastructure equipment and deploy newer technology that improves operational and environmental performance. Capacity payment savings from reduced cogeneration payments and fuel savings from the McClain Plant will be utilized to mitigate the price increases associated with these investments. For additional information regarding the McClain Plant acquisition and related regulatory matters, see Note 18 of Notes to Consolidated Financial Statements. During 2005, the Company will also be focused on controlling and managing operating and maintenance expenses and will continue to analyze the cost structure of the Company's businesses ensuring consistency with the Company's business model. At Enogex during 2005, the Company will focus on enhancing its financial position and the operations of its mid-continent assets as well as seeking to expand into other geographic areas outside of the mid-continent area. Overall, the Company has a strong commitment to train and retain talented personnel so that both the Company and its employees are successful in improving the financial and operating performance of the Company.

The Company's vision is to be a regional energy company focused on its regulated utility business and natural gas pipeline business that is recognized for operational excellence and financial performance. The Company 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 normalized basis, a dividend payout ratio below 75 percent and an A- credit rating.

At Enogex, the Company plans to continue to implement improvements to enhance long-term financial performance of its mid-continent assets through more efficient operations and effective commercial management of the assets. In addition, Enogex is seeking to diversify its gathering, processing and transportation businesses principally by expanding into other geographic areas that are complementary with the Company's strategic capabilities. Enogex's marketing business, which concentrates principally on origination of physical sales of natural gas, has expanded into the Gulf Coast, Rocky Mountain and East Coast markets.

The Company's business strategy is to continue maintaining the diversified asset position of OG&E and Enogex so as to provide competitive energy products and services to customers primarily in the south central United States. The Company will focus on those products and

services with limited or manageable commodity exposure. The Company intends for OG&E to continue as a vertically integrated utility engaged in the generation, transmission and distribution of electricity and to represent over time approximately 70 percent of the Company's consolidated assets. The remainder of the Company's consolidated assets will be in Enogex's businesses. At December 31, 2004, OG&E and Enogex represented approximately 63 percent and 36 percent, respectively, of the Company's consolidated assets. The remaining one percent of the Company's consolidated assets were primarily at the holding company. In addition to the incremental growth opportunities that Enogex provides, the Company believes that many of the risk management practices, commercial skills and market information available from Enogex provide value to all of the Company'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, the Company is applying risk management practices to all of its operations in an effort to mitigate the potential adverse effect of any future regulatory changes.

OG&E has approximately 430 MWs of contracts with qualified cogeneration facilities and small power production producers' ("QF contracts") that will expire at the end of 2007, unless extended by OG&E. In addition, effective September 1, 2004, OG&E entered into a new 15-year power sales agreement for 120 MWs with PowerSmith Cogeneration Project, L.P. ("PowerSmith"). OG&E 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, OG&E 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, OG&E will also assess the feasibility of constructing additional base load coal-fired units.

Enogex initiated a program in 2002 to improve its financial profile and performance. Since January 1, 2002, Enogex has completed significant sales transactions which have generated net sales proceeds of approximately $106.3 million, reduced debt by approximately $226.8 million or 30.6 percent, reduced its number of employees by approximately 12 percent, reorganized its operations and restructured its senior management team. In addition to focusing on growing its earnings, Enogex managed its commodity price and earnings volatility exposures and minimized its exposure to keep-whole processing arrangements. Enogex's profitability increased significantly in 2003 and 2004 due to the performance improvement plan initiated in 2002 as well as an overall favorable business environment coupled with higher commodity prices. While the Company believes substantial progress has been achieved, additional opportunities remain. Enogex continues to review its work processes, evaluate the rationalization of assets, negotiate better terms for both new contracts and replacement contracts, manage costs and pursue opportunities for organic growth, all in an effort to further improve its cash flow and net income.

In addition, Enogex is seeking to diversify its gathering, processing and transportation businesses principally by expanding into other geographic areas that are complementary with the Company's strategic capabilities. Enogex's marketing business, which concentrates principally

on origination of physical sales of natural gas, has expanded into the Gulf Coast, Rocky Mountain and East Coast markets.

In addition to these ongoing efforts, in 2003 Enogex began a major upgrade of its information systems that is expected to be substantially completed during the second and third quarters of 2005. Enogex believes that these upgrades will be a major step towards obtaining the data required to allow it to capture available economic opportunities on its assets, provide improved customer service and enable management to better determine the earnings potential of its various assets and service offerings.

During 2004, Enogex made improvements to the Stuart Storage Facility which reduced water encroachment in the field. During 2004, approximately $1.9 million in capital expenditures was spent on this project. Enogex does not expect any material future expenditures on this water encroachment project.

Forward-Looking Statements

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

Overview

Summary of Operating Results

2004 compared to 2003. The Company reported net income of approximately $153.5 million, or $1.73 per diluted share, as compared to approximately $129.8 million, or $1.58 per

diluted share, for the years ended December 31, 2004 and 2003, respectively. The increase in net income during 2004 as compared to 2003 was primarily due to:

- higher gross margins on revenues (“gross margin”) in Enogex’s gathering and processing business primarily due to an overall favorable business environment coupled with higher commodity prices;
- gains from asset sales; and
- lower net interest expense.

These increases to net income were partially offset by:

- lower gross margins at OG&E due to cooler weather in its service territory; and
- higher operating expenses.

OG&E reported net income of approximately $107.6 million, or $1.22 per diluted share of the Company’s common stock, as compared to approximately $115.4 million, or $1.41 per diluted share, for the years ended December 31, 2004 and 2003, respectively. The decrease in net income at OG&E during 2004 as compared to 2003 is described in more detail below.

Enogex’s operations, including discontinued operations, reported net income of approximately $60.7 million, or $0.69 per diluted share of the Company’s common stock, as compared to approximately $26.9 million, or $0.33 per diluted share, for the years ended December 31, 2004 and 2003, respectively. The increase in net income at Enogex during 2004 as compared to 2003 is described in more detail below.

The results of the holding company reflect a loss of approximately $0.18 per diluted share and $0.16 per diluted share, respectively, for the years ended December 31, 2004 and 2003. The increased loss is primarily due to an increase in net interest expense due to a write off of approximately $5.9 million of unamortized debt issuance costs for the trust preferred securities which were redeemed at par on October 15, 2004, partially offset by an increase in other income.

The Company’s results of operations for the years ended December 31, 2004 and 2003, respectively, include income of approximately $0.5 million, or $0.01 per diluted share, and a loss of approximately $0.4 million, or less than $0.01 per diluted share, from the discontinued operations discussed below. See “Results of Operations – Enogex – Discontinued Operations” for a further discussion.

Earnings per share in 2004 as compared to 2003 were affected by a higher amount of common stock outstanding from the Company’s equity issuance in August 2003 and the issuance of common stock in 2003 and 2004 pursuant to the Company’s Automatic Dividend Reinvestment and Stock Purchase Plan (“DRIP/DSPP”).

2003 compared to 2002. The Company reported net income of approximately $129.8 million, or $1.58 per diluted share, as compared to approximately $90.8 million, or $1.16 per diluted share, for the years ended December 31, 2003 and 2002, respectively. The increase in net income during 2003 as compared to 2002 was primarily due to:

- lower impairment charges at Enogex;
- higher gross margins in all of Enogex’s businesses;
- growth in OG&E’s service territory; and
- lower interest expenses at the holding company.

These increases to net income were partially offset by:

- lower gross margins at OG&E due to lower electric rates as a result of the $25 million electric reduction that went into effect in Oklahoma on January 6, 2003.

OG&E reported net income of approximately $115.4 million, or $1.41 per diluted share, as compared to approximately $126.1 million, or $1.61 per diluted share, for the years ended December 31, 2003 and 2002, respectively. The decrease in net income during 2003 as compared to 2002 is described in more detail below.

Enogex’s operations, including discontinued operations, reported net income of approximately $26.9 million, or $0.33 per diluted share, as compared to a net loss of approximately $21.7 million, or $0.28 per diluted share, for the years ended December 31, 2003 and 2002, respectively. This improvement during 2003 as compared to 2002 is described in more detail below.

The results of the holding company reflect a loss of approximately $0.16 per diluted share and $0.17 per diluted share for the years ended December 31, 2003 and 2002, respectively, primarily due to lower interest expenses and a higher income tax benefit partially offset by higher other miscellaneous expenses.

The Company’s results of operations for the years ended December 31, 2003 and 2002, respectively, include a loss of approximately $0.4 million, or less than $0.01 per diluted share, and income of approximately $9.8 million, or $0.12 per diluted share, from the discontinued operations discussed below. See “Results of Operations – Enogex – Discontinued Operations” for a further discussion.

Regulatory Matters and Plant Acquisition

In November 2002, the OCC issued an order containing provisions of an agreed-upon settlement of OG&E’s rate case. The terms of this settlement included, among other things, a $25.0 million annual reduction in electric rates and a requirement for OG&E to acquire 400 MWs of electric generation. The rate reduction went into effect January 6, 2003 and the acquisition of a 77 percent interest in the 520 MW McClain Plant was completed on July 9, 2004. The McClain Plant, located near Newcastle, Oklahoma, is a combined cycle unit consisting of two natural-gas fired combustion turbine generators combined with a steam turbine generator. The owner of the remaining 23 percent interest in the McClain Plant is the Oklahoma Municipal Power Authority. OG&E operates the plant. The purchase price was approximately $160.0 million. OG&E temporarily funded the McClain Plant acquisition with short-term

borrowings from the Company. On August 4, 2004, OG&E issued $140.0 million of long-term debt to replace these short-term borrowings. Also, on August 9, 2004, the Company made a capital contribution to OG&E of approximately $153.0 million. For additional information regarding the McClain Plant acquisition and related regulatory matters, see Note 18 of Notes to Consolidated Financial Statements.

2005 Outlook

For 2005, the Company's earnings guidance is $137 million to $147 million of net income, or $1.50 to $1.60 per share, assuming approximately 90.5 million average diluted shares outstanding. The 2005 outlook includes earnings guidance of $106 million to $110 million, or $1.17 to $1.22 per share, at OG&E and $39 million to $43 million, or $0.43 to $0.48 per share, at Enogex, while earnings guidance at the holding company is a loss between $6 million and $8 million, or $0.07 to $0.09 per share. During 2005, the Company expects cash flow from operations of between $323 million and $332 million. In 2005, OG&E plans to increase capital expenditures for electric system reliability upgrades. Additionally, funding for the Company's pension plan is expected to be approximately $37.4 million in 2005. Expected 2005 net income assumes a 38.7 percent effective tax rate.

For 2005, OG&E earnings guidance is $106 million to $110 million, or $1.17 to $1.22 per share. OG&E assumes that margin growth approximating one to two percent will be more than offset by increased operating expenses and higher interest costs associated with the acquisition of the McClain Plant and capital expenditures for investment in OG&E's generation, transmission and distribution system. OG&E expects to increase capital expenditures to approximately $248 million for electric system expansion and reliability upgrades in 2005. Key factors affecting OG&E's 2005 net income will be the result of pending regulatory proceedings, weather, OG&E's ability to control operating and maintenance expenses and customer growth. OG&E has significant seasonality in its earnings. OG&E typically shows minimal earnings or slight losses in the first and fourth quarters with a majority of earnings in the third quarter due to the seasonal nature of air conditioning demand. The earnings guidance further assumes no change in base rates and normal weather. OG&E expects to file a rate case during the second quarter of 2005 to recover, among other things, its investment in, and the operating expenses of, the McClain Plant and expects new approved rates to be in effect by January 2006. The earnings guidance also assumes a recovery of the costs associated with the Enogex natural gas transportation and storage services at a level consistent with a recent recommendation by the administrative law judge overseeing this proceeding. On October 22, 2004, the administrative law judge overseeing the proceeding recommended approximately $41.9 million annual demand fee recovery with OG&E refunding to its customers any amounts collected in excess of this amount. If this recommendation is ultimately accepted, OG&E believes its refund obligation would be approximately $6.9 million at December 31, 2004, which the Company does not believe is material in light of previously established reserves. An OCC order in this case is expected in the first quarter of 2005. There can be no guarantee that the OCC will approve the $41.9 million annual demand fee recovery recommended by the administrative law judge. See Note 18 of Notes to Consolidated Financial Statements for a further discussion of this matter.

For 2005, Enogex earnings guidance is $39 million to $43 million, or $0.43 to $0.48 per share. Enogex manages its operations along three related businesses: transportation and storage;

gathering and processing; and marketing. In 2005, these businesses are assumed to produce a gross margin of approximately $269 million, down from $301 million in 2004. The Company expects approximately 46 percent of Enogex's gross margin during 2005 to be generated from its transportation and storage business as compared to 46 percent in 2004. Approximately 88 percent of these gross margins are under firm contracts. Revenues in transportation and storage are primarily from gas transportation contracts with utilities in Oklahoma and Arkansas and independent power producers ("IPP") in Oklahoma. Revenues in the transportation and storage business are expected to decrease due to the completion in 2004 of the over recovery of prior year's under recovered fuel. The Company expects its gathering and processing business to contribute approximately 48 percent of Enogex's gross margin in 2005 as compared to 46 percent in 2004. Revenues in gathering and processing are expected to increase in 2005 primarily due to continued efforts to increase margins from the negotiation of both new contracts and replacement contracts. Volumes are expected to remain flat from 2004. The Company has assumed lower commodity spreads of $1.53 per Million British thermal unit ("MMBtu") in 2005 as compared to $2.45 per MMBtu in 2004 and has assumed lower average natural gas liquids prices of $0.71 per gallon in 2005 as compared to $0.72 per gallon in 2004. The Company also assumes 242 new well connects in its gathering and processing business in 2005. While operating improvements allowed Enogex to capture significant value in a favorable commodity environment, the commodity and well connect assumptions budgeted for 2005 reflect commodity prices that are not as robust as those experienced in 2004. The Company expects its marketing business to contribute approximately six percent of Enogex's gross margin in 2005 as compared to eight percent in 2004. Gross margins in marketing are expected to decrease in 2005 primarily due to 2004 gross margins being above expectations and its anticipated loss of approximately $3.0 million due to its position on the Cheyenne Plains Pipeline as explained in Note 17 of Notes to Consolidated Financial Statements. Enogex also expects approximately $5.1 million in lower operating expenses in 2005 due to not having an $8.6 million impairment charge that was recorded in the third quarter of 2004. In addition, Enogex also expects approximately $1.2 million in lower net interest expense from the retirement of long-term debt in 2004 and 2005. Key factors affecting Enogex's 2005 net income will be new well connections, natural gas and natural gas liquids prices and operating costs. Enogex expects to continue to evaluate the strategic fit and financial performance of each of its assets in an effort to ensure a proper economic allocation of resources. The magnitude and timing of any potential impairment or gain on the disposition of any assets have not been determined or included in the 2005 earnings guidance.

For 2005, earnings guidance at the holding company, which primarily has interest expense but no operating revenue, is a loss between $6 million and $8 million, or $0.07 to $0.09 per share. The decrease in the loss as compared to 2004 is primarily due to lower interest expenses associated with the redemption of $200 million of trust preferred securities on October 15, 2004.

Dividend Policy

The Company's dividend policy is reviewed by the Board of Directors at least annually and is based on numerous factors, including management's estimation of the long-term earnings power of its businesses. The target payout ratio for the Company is to pay out as dividends

approximately 75 percent of its normalized earnings on an annual basis. The target payout ratio has been determined after consideration of numerous factors, including the largely retail composition of our shareholder base, our financial position, our growth targets, the composition of our assets and investment opportunities. While the dividend payout ratio is expected to exceed the target payout ratio in 2005, management after considering estimates of future earnings and numerous other factors, expects at this time that it will continue to recommend to the Board of Directors a continuance of the current dividend rate.

Results of Operations

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

Enogex previously was engaged in the exploration and production of natural gas (the "E&P business"). Since January 1, 2002, Enogex has sold all of its E&P business along with certain gas gathering and processing assets that were owned by Enogex through its interest in the NuStar Joint Venture ("NuStar") and its interest in Belvan Corp., Belvan Limited Partnership and Todd Ranch Limited Partnership ("Belvan"). As required by accounting principles generally accepted in the United States, these dispositions have been reported as discontinued operations for the years ended December 31, 2004, 2003 and 2002 in the Consolidated Financial Statements.

(In millions, except per share data)	**2004**	2003	2002
Operating income	**$ 317.5**	$ 306.9	$ 235.7
Net income	**$ 153.5**	$ 129.8	$ 90.8
Basic average common shares outstanding	**88.0**	81.8	78.1
Diluted average common shares outstanding	**88.5**	82.1	78.2
Basic earnings per average common share	**$ 1.74**	$ 1.59	$ 1.16
Diluted earnings per average common share	**$ 1.73**	$ 1.58	$ 1.16
Dividends declared per share	**$ 1.33**	$ 1.33	$ 1.33

In reviewing its consolidated operating results, the Company believes that it is appropriate to focus on operating income as reported in its Consolidated 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. Included in 2004, 2003 and 2002 operating income are pre-tax impairment charges of approximately $7.8 million, $10.2 million and $50.1 million, respectively. These impairments, primarily for Enogex natural gas processing and compression assets that were no longer needed in Enogex's business, were made in accordance with accounting principles generally accepted in the United States.

Operating Income (Loss) by Business Segment

(In millions)	**2004**	2003	2002
OG&E (Electric Utility)	**$ 192.0**	$ 216.2	$ 239.1
Enogex (Natural Gas Pipeline) (A)	**126.6 (B)**	91.2 (B)	(3.0) (B)
Other Operations (C)	**(1.1)**	(0.5)	(0.4)
Consolidated operating income	**$ 317.5**	$ 306.9	$ 235.7

(A) Excludes discontinued operations. See "Enogex - Discontinued Operations" for a further discussion.
(B) After recording pre-tax impairment charges of approximately $7.8 million, $9.2 million and $48.3 million 2004, 2003 and 2002, respectively.
(C) Other Operations primarily includes unallocated corporate expenses.

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

OG&E

(Dollars in millions)	**2004**	2003	2002
Operating revenues	**$ 1,578.1**	$ 1,517.1	$ 1,388.0
Fuel	**645.4**	544.5	435.8
Purchased power	**269.1**	292.9	260.0
Gross margin on revenues	**663.6**	679.7	692.2
Other operating and maintenance	**301.9**	294.8	282.9
Depreciation	**122.7**	121.8	123.1
Taxes other than income	**47.0**	46.9	47.1
Operating income	**$ 192.0**	$ 216.2	$ 239.1
Operating revenues by classification			
Residential	**$ 611.4**	$ 601.4	$ 557.6
Commercial	**389.9**	372.5	346.9
Industrial	**326.7**	293.4	258.6

Public authorities	**158.5**	146.1	135.5
Sales for resale	**57.0**	57.7	48.2
Provision for refund on gas transportation and storage case	**(6.9)**	---	---
Other	**40.7**	41.9	34.9
System sales revenues	**1,577.3**	1,513.0	1,381.7
Off-system sales revenues	**0.8**	4.1	6.3
Total operating revenues	**$ 1,578.1**	$ 1,517.1	$ 1,388.0
MWH (A) sales by classification (in millions)			
Residential	**7.9**	8.2	8.0
Commercial	**5.7**	5.8	5.8
Industrial	**7.0**	6.8	6.6
Public authorities	**2.7**	2.7	2.7
Sales for resale	**1.4**	1.5	1.5
System sales	**24.7**	25.0	24.6
Off-system sales	**0.1**	0.1	0.3
Total sales	**24.8**	25.1	24.9
Number of customers	**735,008**	725,470	718,513
Average cost of energy per KWH (B) - cents			
Fuel	**2.887**	2.454	1.897
Fuel and purchased power	**3.436**	3.128	2.614
Degree days (C)			
Heating			
Actual	**3,114**	3,488	3,753
Normal	**3,650**	3,631	3,634
Cooling			
Actual	**1,839**	1,898	1,847
Normal	**1,911**	1,911	1,911

(A) Megawatt-hour.
(B) Kilowatt-hour.
(C) Degree days are calculated as follows: The high and low degrees of a particular day are added together and then averaged. If the calculated average is above 65 degrees, then the difference between the calculated average and 65 is expressed as cooling 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.

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

- lower gross margins due to cooler weather in OG&E’s service territory;
- lower margins related to sales to wholesale customers;
- the timing of fuel recoveries; and
- higher operating expenses.

These decreases in operating income were partially offset by:

- growth in OG&E’s service territory.

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

- cooler weather in OG&E’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:

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

Cost of goods sold for OG&E consists of fuel used in electric generation and purchased power. Fuel expense was approximately $645.4 million in 2004 as compared to approximately $544.5 million in 2003, an increase of approximately $100.9 million or 18.5 percent. The increase was primarily due to an increase in the average cost of fuel per kwh, primarily due to higher natural gas prices despite lower mwh sales. OG&E's electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for OG&E and its customers. In 2004, OG&E'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 OG&E 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 OG&E's acquisition of the McClain Plant in July 2004 and the termination of power purchase contracts in December 2003 and August 2004.

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component included in the cost-of-service for ratemaking, are passed through to OG&E's customers through automatic fuel adjustment clauses. While the regulatory mechanisms for recovering fuel costs differ in Oklahoma, Arkansas and the FERC, in each jurisdiction the costs are passed through to customers and are intended to provide neither an ultimate benefit nor detriment to OG&E. The automatic fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC. The OCC, the APSC and the FERC have authority to review the appropriateness of gas transportation charges or other fees OG&E pays to Enogex. See Note 18 of Notes to Consolidated Financial Statements for a discussion of current proceedings at the OCC regarding OG&E's gas transportation and storage contract with Enogex.

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

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

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

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

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

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

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

These decreases in operating income were partially offset by:

- o growth in OG&E's service territory.

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

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

These decreases in gross margin were partially offset by:

- o growth in OG&E's service territory which increased the gross margin by approximately $17.5 million.

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

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

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

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

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

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

Enogex – Continuing Operations

(Dollars in millions)	**2004**	2003	2002
Operating revenues	**$ 3,443.9**	$ 2,327.8	$ 1,684.0
Gas and electricity purchased for resale (A)	**3,054.3**	2,019.1	1,402.1
Natural gas purchases - other	**88.6**	55.4	70.5
Gross margin on revenues	**301.0**	253.3	211.4
Other operating and maintenance	**101.5**	91.2	101.1
Depreciation	**47.6**	44.2	49.3
Impairment of assets	**7.8**	9.2	48.3
Taxes other than income	**17.5**	17.5	15.7
Operating income (loss)	**$ 126.6**	$ 91.2	$ (3.0)
New well connects	**277**	232	166
Gathered volumes - TBtu/d (B)	**1.01**	0.99	1.06
Incremental transportation volumes - TBtu/d	**0.51**	0.44	0.49
Total throughput volumes - TBtu/d	**1.52**	1.43	1.55
Natural gas processed - Mmcf/d (C)	**502**	414	455
Natural gas liquids sold (keep whole) - million gallons	**263**	207	285
Natural gas liquids sold (POL and fixed-fee) - million gallons	**16**	18	22
Total natural gas liquids sold - million gallons	**279**	225	307
Average sales price per gallon	**$ 0.720**	$ 0.595	$ 0.406

(A) OGE Energy Resources, Inc. ("OERI") exited the power marketing business during the first quarter of 2004.
(B) Trillion British thermal units per day.
(C) Million cubic feet per day.

2004 compared to 2003. Enogex's operating income in 2004 increased approximately $35.4 million or 38.8 percent as compared to 2003. The increase in operating income was primarily attributable to higher gross margins in Enogex's gathering and processing business primarily due to an overall favorable business environment coupled with higher commodity prices and revenue improvements generated from the negotiation of both new contracts and replacement contracts at better terms. These increases were partially offset by higher operating expenses.

Enogex sold its interest in NuStar during the first quarter of 2003; accordingly this is reported as discontinued operations for the years ended December 31, 2004, 2003 and 2002 in the Consolidated Financial Statements. See "Enogex – Discontinued Operations" for a further discussion.

Transportation and storage contributed approximately $137.4 million of Enogex's gross margin in 2004 as compared to approximately $138.1 million in 2003, a decrease of approximately $0.7 million or 0.5 percent. The gross margin decreased primarily due to:

- certain contractual revenues recorded in transportation and storage in 2003 being recorded in gathering and processing in 2004 which reduced the gross margin by approximately $12.7 million;
- mark-to-market timing losses on natural gas storage inventory which reduced the gross margin by approximately $3.7 million;

- the Calpine Energy Services, L.P. ("Calpine Energy") settlement in 2003 which resulted in a one-time increase of approximately $2.0 million to the gross margin in 2003;
- the net change between fuel retained and fuel consumed which decreased the gross margin by approximately $1.7 million; and
- third party pipeline imbalances which decreased the gross margin by approximately $1.0 million.

These decreases in the transportation and storage gross margin were partially offset by:

- higher purchases and sales activity due to Enogex being more active in the marketplace which increased the gross margin by approximately $6.6 million;
- higher interruptible revenues and higher crosshaul revenues due to an increase in interruptible contract volumes and increased crosshaul margins and volumes which increased the gross margin by approximately $6.3 million;
- higher transportation and storage revenues in 2004 primarily due to the additional demand fees and overrun charges from the transportation and storage contract with OG&E, which was effective May 2003, which increased the gross margin by approximately $4.9 million; and
- an amended intercompany natural gas purchase contract which increased the gross margin by approximately $2.5 million.

Gathering and processing contributed approximately $139.8 million of Enogex's gross margin in 2004 as compared to approximately $91.3 million in 2003, an increase of approximately $48.5 million or 53.1 percent. Gathering gross margins increased approximately $27.5 million in 2004 as compared to 2003 primarily due to:

- the change in 2004 discussed above of recording certain contractual revenues in gathering and processing rather than in transportation and storage, which increased the gross margin by approximately $12.7 million;
- revenue improvements generated from an overall favorable business environment coupled with higher commodity prices and the negotiation of both new contracts and replacement contracts at better terms; and
- an increase in the number of well connects and the volumes of natural gas gathered.

Processing gross margins increased approximately $21.0 million in 2004 as compared to 2003 primarily due to:

- increased keep-whole, percent of liquids and condensate margins due to favorable commodity prices and higher keep-whole volumes which increased the gross margin by approximately $21.9 million; and
- an expense reallocation of compressor fuel (from processing in 2003 to transportation and storage in 2004) which increased the gross margin by approximately $1.3 million.

Marketing contributed approximately $23.8 million of Enogex's gross margin in 2004 as compared to approximately $23.9 million in 2003, a decrease of approximately $0.1 million or 0.4 percent. The gross margin decreased primarily due to:

- lower gains from the sale of natural gas in storage in 2004 of approximately $12.1 million primarily due to Enogex recording approximately a $9.0 million pre-tax loss as a cumulative effect of a change in accounting principle in the first quarter of 2003 rather than recording this loss as a reduction of the gross margin. The cumulative effect of a change in accounting principle was the result of accounting for certain energy contracts and natural gas in storage at the lower of cost or market rather than on a mark-to-market basis (see Note 2 of Notes to Consolidated Financial Statements for a further discussion);
- mark-to-market timing losses on natural gas storage inventory due to different pricing environments during 2004 as compared to 2003 which reduced the gross margin by approximately $2.2 million; and
- exiting the power marketing business in 2004 which reduced the gross margin by approximately $1.1 million.

These decreases in the marketing gross margin were partially offset by:

- new business activity in the marketing portfolio which increased the gross margin by approximately

$12.2 million; and

- lower demand fees expense for storage services due to establishing new rates for the new storage season which began April 1 which increased the gross margin by approximately $3.4 million.

Enogex's other operating and maintenance expenses were approximately $101.5 million in 2004 as compared to approximately $91.2 million in 2003, an increase of approximately $10.3 million or 11.3 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher payroll, benefit and pension expenses of approximately $4.1 million due to hiring new employees, payment of overtime and salary increases;
- higher outside service costs of approximately $2.4 million related to work performed to maintain the integrity and safety of Enogex's pipeline;
- higher materials and supplies expense of approximately $2.3 million for repairs and maintenance of systems; and
- higher uncollectibles expense of approximately $1.4 million due to miscellaneous accounts receivable items becoming over 180 days old.

Depreciation expense was approximately $47.6 million in 2004 as compared to approximately $44.2 million in 2003, an increase of approximately $3.4 million or 7.7 percent. The increase was primarily due to a higher level of depreciable plant as the implementation of an information system was completed during the second quarter of 2004 in addition to accelerated depreciation recorded during the fourth quarter of 2004 related to the impairment involving four of Enogex's non-contiguous pipeline asset segments.

Impairment of assets was approximately $7.8 million in 2004 as compared to approximately $9.2 million in 2003, a decrease of approximately $1.4 million or 15.2 percent. During September 2004, Enogex received notification from a customer that a transportation agreement involving four of Enogex's non-contiguous pipeline asset segments located in West Texas and used to serve the customer's power plants would be terminated effective December 31, 2004. In connection with the preparation of the third quarter 2004 financial statements, Enogex performed an evaluation on these assets and concluded that an impairment charge needed to be recorded. The primary reason for this determination was that these four pipeline asset segments were originally built for the specific purpose of providing gas transmission service to this customers' four power plants that have been or are in the process of being shut down, and, as a result, other alternative commercial uses for these facilities are considered unlikely. Also, in 2004, the Company reclassified several compressors and processing plants that were previously classified as assets held for sale to assets held and used. This decision was based on the fact these assets are no longer being marketed and the Company believes the value of the future benefit of holding these assets exceeds the current fair market value. As a result, in accordance with Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards ("SFAS") No. 144, "Accounting for the Impairment or Disposal of Long–Lived Assets," the Company determined the fair value of these assets based on a third party valuation of the assets and, as a result, the Company recorded a net gain of approximately $0.8 million during 2004 related to reclassifying these assets from assets held for sale to assets held and used, which was recorded as a credit to Impairment of Assets on the Consolidated Statements of Income. During 2003, an evaluation of the horsepower of compression needed to meet the operational requirements of the Company's gathering and transmission system was performed based on the then current market conditions. The review identified compressor equipment that could be removed from the system and a pre-tax impairment loss of approximately $9.2 million was recorded in the fourth quarter of 2003 to recognize the difference between the carrying value of these units and their fair value expected to be realized in a disposal. The impairment recorded in the fourth quarter of 2003 resulted from plans to dispose of these assets at prices below the carrying amount. The fair value of these assets was determined based on third-party evaluations, prices for similar assets, historical data and projected cash flows.

During the year ended December 31, 2004, Enogex had an increase in net income of approximately $4.9 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex's business. These increases in net income include:

- authorized recovery of previously under recovered fuel of approximately $3.8 million;
- a gain on the sale of Enogex compression and processing assets of approximately $1.8 million;
- an imbalance settlement with a customer of approximately $1.6 million;
- a net Oklahoma investment tax credit of approximately $1.5 million;
- a settlement related to a customer bankruptcy of approximately $0.5 million; and
- income from discontinued operations of approximately $0.5 million.

These increases to net income were partially offset by:

- a net impairment charge of approximately $4.8 million.

During the year ended December 31, 2003, Enogex had an increase in net income of approximately $3.6 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex's business. These increases in net income include:

- authorized recovery of previously under recovered fuel of approximately $6.5 million;
- a gain on the sale of assets of approximately $2.6 million;
- a settlement related to a dispute with Calpine Energy of approximately $1.2 million; and
- a pricing adjustment on a processing contract with a customer of approximately $1.1 million.

These increases to net income were partially offset by:

- an impairment charge of approximately $5.7 million;
- an income tax adjustment of approximately $1.7 million; and
- a loss from discontinued operations of approximately $0.4 million.

2003 compared to 2002. Enogex's operating income in 2003 increased approximately $94.2 million as compared to 2002. The increase in operating income was primarily attributable to:

- lower impairment charges;
- higher gross margins in all of Enogex's businesses, from among other things, improved management of pipeline system fuel, increased levels of firm transportation revenues, improved processing results and the negotiation of both new contracts and replacement contracts at better terms; and
- lower operating and maintenance expenses.

Enogex sold its E&P business and its interest in Belvan during 2002 and Enogex sold its interest in NuStar during the first quarter of 2003; accordingly, these are reported as discontinued operations for the years ended December 31, 2003 and 2002 in the Consolidated Financial Statements. See "Enogex – Discontinued Operations" for a further discussion.

Transportation and storage contributed approximately $138.1 million of Enogex's gross margin in 2003 as compared to approximately $120.8 million in 2002, an increase of approximately $17.3 million or 14.3 percent. The gross margin increased primarily due to:

- improved management of pipeline system fuel which, when coupled with higher natural gas prices, accelerated the authorized recovery of pipeline system fuel

  expense, which was the result of Enogex under recovering fuel in prior periods which increased the gross margin by approximately $11.8 million;
- higher storage revenues primarily due to new demand fees from the contract with OG&E related to the purchase of the Stuart Storage Facility in August 2002 and increased demand fees from both third parties and Enogex's marketing business which increased the gross margin by approximately $8.8 million; and
- higher levels of firm transportation revenues as a result of the Calpine Energy settlement and an increase in related demand fees recognized in 2003 which collectively increased the gross margin by approximately $5.7 million.

These increases in the transportation and storage gross margin were partially offset by:

- lower interruptible revenues related to bundled contracts due to a revenue reallocation (from Enogex's transportation and storage business to Enogex's gathering and processing business) to more accurately reflect the performance of Enogex' businesses which reduced the gross margin by approximately $2.8 million;
- higher electric compression costs which reduced the gross margin by approximately $1.2 million; and
- an imbalance collectibility reserve which reduced the gross margin by approximately $1.2 million.

Gathering and processing contributed approximately $91.3 million of Enogex's gross margin in 2003 as compared to approximately $73.0 million in 2002, an increase of approximately $18.3 million or 25.1 percent. Gathering gross margins increased approximately $9.8 million in 2003 as compared to 2002 primarily due to:

- higher interruptible revenues related to bundled contracts due to a revenue reallocation related to bundled contracts (from Enogex's transportation and storage business to Enogex's gathering and processing business) to more accurately reflect the performance of Enogex's businesses which increased the gross margin by approximately $2.8 million;
- revenue improvements generated from the negotiation of both new contracts and replacement contracts at better terms; and
- an increase in the number of well connects.

Processing gross margins increased approximately $8.5 million in 2003 as compared to 2002 primarily due to:

- wider commodity spreads between natural gas and natural gas liquids; and
- better management and dispatch of the plants; however, processing volumes were lower as a result of economic dispatching of the network of processing plants based upon market conditions.

Marketing contributed approximately $23.9 million of Enogex's gross margin in 2003 as compared to approximately $17.6 million in 2002, an increase of approximately $6.3 million or 35.8 percent. The gross margin increased primarily due to:

- higher gains from the sale of natural gas in storage in 2003 of approximately $10.2 million primarily due to Enogex recording approximately a $9.0 million pre-tax loss as a cumulative effect of a change in accounting principle in the first quarter of 2003 rather than recording this loss as a reduction of the gross margin. The cumulative effect of a change in accounting principle was the result of accounting for certain energy contracts and natural gas in storage at the lower of cost or market rather than on a mark-to-market basis (see Note 2 of Notes to Consolidated Financial Statements for a further discussion).

This increase in the marketing gross margin was partially offset by:

- higher demand fees expense paid to Enogex's transportation and storage business which reduced the gross margin by approximately $2.2 million; and
- a change in the timing of revenue recognition related to natural gas in storage under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended, in 2003 as compared to mark-to-market accounting in 2002 which reduced the gross margin by approximately $0.9 million. This accounting change was driven by the rescission of mark-to-market accounting for natural gas in storage as a result of Emerging Issues Task Force ("EITF") Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," which was issued in October 2002 (see Note 2 of Notes to Consolidated Financial Statements for a further discussion).

Enogex's other operating and maintenance expenses were approximately $91.2 million in 2003 as compared to approximately $101.1 million in 2002, a decrease of approximately $9.9 million or 9.8 percent. The decrease in other operating and maintenance expenses was primarily due to:

- lower uncollectibles expense of approximately $4.9 million due to establishing reserves in 2002 related to two customer bankruptcies;
- lower materials and supplies expense of approximately $4.2 million due to the active use of inventories;
- lower expense allocations from the parent of approximately $1.6 million due to the closing of two natural gas processing plants in 2003; and
- lower miscellaneous operating expenses in 2003 due to termination benefits of approximately $0.9 million.

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

- higher outside service costs of approximately $2.0 million related to work performed to maintain the integrity and safety of Enogex's pipeline as well as the cost of new well connects.

Depreciation expense was approximately $44.2 million in 2003 as compared to approximately $49.3 million in 2002, a decrease of approximately $5.1 million or 10.3 percent. The decrease was primarily the result of ceasing depreciation on the assets written down as of December 31, 2002 due to the Company's decision to sell these assets and classify them as held for sale in the fourth quarter of 2002.

Impairment charges were approximately $9.2 million in 2003 as compared to approximately $48.3 million in 2002, a decrease of approximately $39.1 million or 81.0 percent. The impairment charges in 2003 and 2002 related to certain idle Enogex natural gas compression assets.

Taxes other than income were approximately $17.5 million in 2003 as compared to approximately $15.7 million in 2002, an increase of approximately $1.8 million or 11.5 percent. The increase was the result of higher ad valorem taxes.

During the year ended December 31, 2003, Enogex had an increase in net income of approximately $3.6 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex's business. These increases in net income include:

- authorized recovery of previously under recovered fuel of approximately $6.5 million;
- a gain on the sale of assets of approximately $2.6 million;
- a settlement related to a dispute with Calpine Energy of approximately $1.2 million; and
- a pricing adjustment on a processing contract with a customer of approximately $1.1 million.

These increases to net income were partially offset by:

- an impairment charge of approximately $5.7 million;
- an income tax adjustment of approximately $1.7 million; and
- a loss from discontinued operations of approximately $0.4 million.

During the year ended December 31, 2002, Enogex had a decrease in net income of approximately $26.4 million relating to various items that the Company does not consider to be reflective of the ongoing profitability of Enogex's business. The decrease in net income includes:

- an impairment charge of approximately $31.1 million;
- a reserve for two customer bankruptcies of approximately $2.8 million; and

- a reserve for unpaid demand fees related to a dispute with Calpine Energy of approximately $2.3 million.

These decreases to net income were partially offset by:

- income from discontinued operations of approximately $9.8 million.

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

2004 compared to 2003. Other income includes, among other things, contract work performed by OG&E, non-operating rental income, gain on the sale of assets, minority interest income and miscellaneous non-operating income. Other income was approximately $12.1 million in 2004 as compared to approximately $8.1 million in 2003, an increase of approximately $4.0 million or 49.4 percent. The increase in other income was primarily due to:

- a realized gain of approximately $3.2 million from the sale of OG&E’s interests in its natural gas producing properties;
- a realized gain of approximately $3.0 million on the sale of certain of Enogex’s compression and processing assets;
- appreciation of investments associated with certain participants’ contributions in the deferred compensation plan and restoration of retirement income plan of approximately $1.0 million;
- increased allowance for equity funds used during construction in 2004 of approximately $0.9 million;
- a bankruptcy settlement from one of the Company’s customers of approximately $0.8 million;
- a realized gain of approximately $0.6 million from the repurchase of outstanding heat pump loans; and
- a realized gain of approximately $0.3 million from the sale of land and buildings near the Company’s principal executive offices.

These increases in other income were partially offset by:

- a realized gain of approximately $5.3 million related to the sale of approximately 29 miles of transmission lines of the Ozark pipeline in the first quarter of 2003.

Other expense includes, among other things, expenses from the losses on the sale of assets, minority interest expense, miscellaneous charitable donations, expenditures for certain civic, political and related activities and miscellaneous deductions. Other expense was approximately $5.5 million in 2004 as compared to approximately $9.0 million in 2003, a decrease of approximately $3.5 million or 38.9 percent. The decrease in other expense was primarily due to:

- realized losses of approximately $1.3 million from the sale of miscellaneous assets in 2003;

- minority interest expense of approximately $1.1 million in the first quarter of 2003 related to the gain from the sale of approximately 29 miles of transmission lines of the Ozark pipeline that was attributable to the minority interest; and
- a loss from the dissolution of a lease in the third quarter of 2003 of approximately $0.7 million.

Net interest expense includes interest income, interest expense and other interest charges. Net interest expense was approximately $90.9 million in 2004 as compared to approximately $96.7 million in 2003, a decrease of approximately $5.8 million or 6.0 percent. The decrease in net interest expense was primarily due to:

- a reduction in interest expense of approximately $5.0 million due to the reduction and early retirement of long-term debt;
- an increase in interest income of approximately $3.6 million due to the interest portion of an income tax refund related to prior periods;
- a reduction in interest expense and commercial paper service fees of approximately $1.6 million due to the Company having a lower average commercial paper balance outstanding 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.

These decreases in net interest expense were partially offset by:

- an increase in interest expense of approximately $5.9 million due to the write off of unamortized debt issuance costs for the trust preferred securities; and
- an increase in interest expense of approximately $0.7 million due to the issuance of long-term debt in November 2004.

Income tax expense was approximately $80.2 million in 2004 as compared to approximately $73.7 million in 2003, an increase of approximately $6.5 million or 8.8 percent. The increase in income tax expense was primarily due to:

- higher pre-tax income for Enogex.

This increase in income tax expense was partially offset by:

- o lower pre-tax income for OG&E; and
- o the recognition of additional Oklahoma state tax credits of approximately $4.1 million during 2004.

2003 compared to 2002. Other income was approximately $8.1 million in 2003 as compared to approximately $3.7 million in 2002, an increase of approximately $4.4 million. The increase in other income was primarily due to:

- o a realized gain of approximately $5.3 million related to the sale of approximately 29 miles of transmission lines of the Ozark pipeline in the first quarter of 2003.

This increase in other income was partially offset by:

- o lower appreciation of investments in 2003 as compared to 2002 associated with certain participants' contributions in the deferred compensation plan of approximately $0.9 million.

Other expense was approximately $9.0 million in 2003 as compared to approximately $4.7 million in 2002, an increase of approximately $4.3 million or 91.5 percent. The increase in other expense was primarily due to:

- o minority interest expense of approximately $1.1 million in the first quarter of 2003 related to the gain from the sale of approximately 29 miles of transmission lines of the Ozark pipeline that was attributable to the minority interest;
- o an increased liability associated with the deferred compensation plan approximately a $1.0 million;
- o a loss on the retirement of fixed assets of approximately $0.9 million;
- o a loss from the dissolution of a lease in the third quarter of 2003 of approximately $0.7 million; and
- o a loss from the sale of the Company's aircraft in the third quarter of 2003 of approximately $0.1 million.

Net interest expense was approximately $96.7 million in 2003 as compared to approximately $109.1 million in 2002, a decrease of approximately $12.4 million or 11.4 percent. The decrease in net interest expense was primarily due to:

- o a reduction in interest expense of approximately $7.9 million related to the retirement of $140.0 million of Enogex debt during 2002;
- o a reduction in interest expense of approximately $2.5 million due to a lower average commercial paper balance in 2003 as compared to 2002; and
- o a reduction in interest expense of approximately $2.3 million related to lower interest rates on outstanding debt achieved from entering into interest rate swap agreements.

Income tax expense was approximately $73.7 million in 2003 as compared to approximately $44.6 million in 2002, an increase of approximately $29.1 million or 65.2 percent. The increase in income tax expense was primarily due to:

- o higher pre-tax income for Enogex.

This increase in income tax expense was partially offset by:

- o lower pre-tax income for OG&E;
- o a greater deduction for the Company's Employee Stock Ownership Plan dividends in 2003, which reduced taxable income as compared to 2002;
- o a reversal of previously accrued federal income tax in 2002 related to several issues that were resolved in favor of the Company; and

- o an Oklahoma income tax refund in 2002 related to Oklahoma investment tax credits from prior years.

Enogex – Discontinued Operations

Enogex sold its interests in Belvan for approximately $9.8 million in March 2002. The Company recognized an after tax gain of approximately $1.6 million related to the sale of these assets.

Enogex sold its exploration and production assets located in Oklahoma, Texas, Arkansas and Mississippi for approximately $15.0 million in August 2002. The Company recognized an after tax gain of approximately $2.3 million related to the sale of these assets.

Enogex sold its exploration and production assets located in Michigan for approximately $32.0 million in November 2002. The Company recognized an after tax gain of approximately $2.9 million related to the sale of these assets.

Enogex sold its interests in NuStar for approximately $37.0 million in February 2003. The Company recognized an after tax gain of approximately $1.4 million related to the sale of these assets in the first quarter of 2003. Following completion of the final accounting for the NuStar sale, the Company recorded an additional charge of approximately $0.2 million after tax in the third quarter of 2003. The final accounting is subject to approval by all parties to the sale of the joint venture interest. During 2004, the Company recognized approximately $0.5 million after tax from funds received related to an overpayment for natural gas purchases in a prior period.

As a result of these sale transactions, Enogex's E&P business, its interest in NuStar and its interest in Belvan, all of which were part of the Natural Gas Pipeline segment, have been reported as discontinued operations for the years ended December 31, 2004, 2003 and 2002 in the Consolidated Financial Statements. Results for these discontinued operations are summarized and discussed below.

(In millions)	**2004**	2003	2002
Operating revenues	**$ 0.8**	$ 7.8	$ 79.5
Gas purchased for resale	---	5.9	49.5
Natural gas purchases - other	---	0.6	6.4
Gross margin on revenues	**0.8**	1.3	23.6
Other operation and maintenance	---	1.1	12.1
Depreciation	---	0.2	4.4
Taxes other than income	---	0.1	0.6
Operating income (loss)	**0.8**	(0.1)	6.5
Other income	---	1.9	1.8
Net interest income	---	---	0.1
Income tax expense (benefit)	**0.3**	2.2	(1.4)
Net income (loss)	$ **0.5**	$ (0.4)	$ 9.8

2004 compared to 2003. Following the sale of NuStar in February 2003, no operations of NuStar are reflected in the Consolidated Financial Statements except for approximately $0.8 million received during 2004 related to an overpayment of natural gas purchases in a prior period.

2003 compared to 2002. Gross margin decreased approximately $22.3 million or 94.5 percent in 2003 as compared to 2002. Other operating and maintenance expenses decreased approximately $11.0 million or 90.9 percent, depreciation expense decreased $4.2 million or 95.5 percent and taxes other than income decreased approximately $0.5 million or 83.3 percent in 2003 as compared to 2002. The decreases in the gross margin, other operating and maintenance expenses, depreciation expense and taxes other than income were attributable to the sale of Enogex's E&P business and Belvan during 2002 and the sale of NuStar in February 2003.

Financial Condition

The balance of Cash and Cash Equivalents was approximately $26.4 million and $245.6 million at December 31, 2004 and 2003, respectively, a decrease of approximately $219.2 million or 89.3 percent. The balance at December 31, 2003 was primarily due to an increase in short-term investments at December 31, 2003 in anticipation of the need for funds to purchase the McClain Plant, which was originally expected to occur by December 31, 2003, and, which was ultimately completed on July 9, 2004.

The balance of Accounts Receivable was approximately $487.9 million and $350.2 million at December 31, 2004 and 2003, respectively, an increase of approximately $137.7 million or 39.3 percent. The increase was primarily due to higher natural gas prices and volumes associated with Enogex's activities in the fourth quarter of 2004 partially offset by improved collection efforts at OG&E.

The balance of Fuel Inventories was approximately $89.0 million and $149.6 million at December 31, 2004 and 2003, respectively, a decrease of approximately $60.6 million or 40.5 percent. The decrease was primarily due to inventory sales at Enogex during 2004.

The balance of current Price Risk Management assets was approximately $118.6 million and $61.3 million at December 31, 2004 and 2003, respectively, an increase of approximately $57.3 million or 93.5 percent. The increase was primarily due to an increase in park and loan transactions, natural gas storage injections and withdrawals and related financial contracts associated with OERI's activities during 2004.

The balance of the Gas Imbalance asset was approximately $100.1 million and $70.0 million at December 31, 2004 and 2003, respectively, an increase of approximately $30.1 million or 43.0 percent. The Gas Imbalance asset is comprised of planned or managed imbalances related to Enogex's marketing business, referred to as park and loan transactions, and pipeline and natural gas liquids imbalances, which are operational imbalances. Park and loan transactions were approximately $76.0 million and $45.4 million at December 31, 2004 and 2003, respectively, an increase of approximately $30.6 million or 67.4 percent. The increase was due

to an increase in park and loan transactions during 2004 resulting from economic opportunities in the marketplace.

The balance of Fuel Clause Under Recoveries was approximately $54.3 million at December 31, 2004. The balance of Fuel Clause Over Recoveries (net of Fuel Clause Under Recoveries) was approximately $28.4 million at December 31, 2003. The increase in fuel clause under recoveries was due to under recoveries from OG&E's customers as OG&E's cost of fuel exceeded the amount billed during 2004. The cost of fuel subject to recovery through the fuel clause mechanism was approximately $2.43 per MMBtu in December 2004, and was approximately $1.21 per MMBtu in December 2003. OG&E's fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result, OG&E 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 OG&E to amortize under or over recovery. OG&E expects to recover the fuel clause under recoveries during 2005.

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

The balance of Prepaid Benefit Obligation was approximately $92.7 million and $55.7 million at December 31, 2004 and 2003, respectively, an increase of approximately $37.0 million or 66.4 percent. The increase was primarily due to the Company funding its pension plan during the second and third quarters of 2004 partially offset by pension accruals being credited to the prepaid benefit obligation.

The balance of Short-Term Debt was approximately $125.0 million and $202.5 million at December 31, 2004 and 2003, respectively, a decrease of approximately $77.5 million or 38.3 percent. The balance at December 31, 2003 was primarily due to the incurrence of short-term debt in anticipation of the expected 2003 year-end closing of the acquisition of the McClain Plant, which was ultimately completed on July 9, 2004. In conjunction with the acquisition of the McClain Plant, the Company issued short-term debt to fund a portion of the acquisition, and, as a result, the short-term debt balance was approximately $216.1 million at July 31, 2004. On August 4, 2004, OG&E issued $140.0 million of long-term debt to replace these short-term borrowings. During October 2004, the Company issued approximately $170.0 million in commercial paper related to the redemption of the trust preferred securities, of which approximately $100.0 million was refinanced in November 2004 by the issuance of long-term debt.

The balance of Accounts Payable was approximately $476.2 million and $280.2 million at December 31, 2004 and 2003, respectively, an increase of approximately $196.0 million or 70.0 percent. The increase was primarily due to higher natural gas prices and volumes associated with Enogex's activities in the fourth quarter of 2004.

The balance of current Price Risk Management liabilities was approximately $102.9 million and $46.9 million at December 31, 2004 and 2003, respectively, an increase of approximately $56.0 million. The increase was primarily due to an increase in park and loan transactions, natural gas storage injections and withdrawals and related financial contracts associated with OERI's activities during 2004.

The balance of Long-Term Debt was approximately $1.42 billion and $1.44 billion at December 31, 2004 and 2003, respectively, a decrease of approximately $20 million or 1.4 percent. The decrease was primarily due to long-term debt maturities and the early retirement of long-term debt during 2004. These decreases were partially offset by the issuance of $140.0 million of long-term debt in August 2004 by OG&E to replace the short-term borrowings initially issued to finance the McClain Plant acquisition in addition to the issuance of $100.0 million of long-term debt in November 2004 related to the redemption of the trust preferred securities in October 2004.

The balance of Accrued Pension and Benefit Obligations was approximately $197.0 million and $167.4 million at December 31, 2004 and 2003, respectively, an increase of approximately $29.6 million or 17.7 percent. The increase was primarily due to an increase in the liability associated with the Company's pension plan due to a decrease in the assumed discount rate. See Note 15 of Notes to Consolidated 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 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 stockholders' equity in the Company's consolidated balance sheet; or (iv) any obligation, including a contingent obligation, arising out of a variable interest as defined in FASB Interpretation No. 46, "Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51," in an unconsolidated entity that is held by, and material to, the Company, where such entity provides financing, liquidity, market risk or credit risk support to, or engages in leasing, hedging or research and development services with, the Company. The Company has the following off-balance sheet arrangements.

Heat Pump Loans

Prior to January 1, 2004, OG&E had a heat pump loan program that allowed qualifying customers to obtain a loan from OG&E to purchase a heat pump. In October 1998, OG&E sold approximately $25.0 million of its heat pump loans in a securitization transaction through OGE Consumer Loan LLC. During the second quarter of 2004, OG&E repurchased the outstanding heat pump loan balance of approximately $0.1 million. OG&E recorded a gain of approximately $0.6 million in the third quarter of 2004 related to this transaction. Effective November 19, 2004, the Company dissolved OGE Consumer Loan LLC. In November 1999, OG&E sold approximately $12.7 million of its heat pump loans in a securitization transaction through OGE Consumer Loan II LLC. In October 2004, OG&E repurchased the outstanding heat pump loan balance of approximately $1.1 million. OG&E recorded a loss of less than $0.1 million in the fourth quarter of 2004 related to this transaction. Effective January 31, 2005, the Company dissolved OGE Consumer Loan II LLC. Effective January 1, 2004, OG&E discontinued issuing heat pump loans to customers and all new heat pump loans are now processed and managed by a third party. OG&E continues to service the heat pump loans it recently repurchased in 2004 in addition to the heat pump loans OG&E sold during 2003. The finance rate on the heat pump loans was based upon market rates and was reviewed and updated periodically. The interest rate was 11.55 percent at December 31, 2003. OG&E's heat pump loan balance was approximately $1.3 million and $1.4 million at December 31, 2004 and 2003, respectively and is included in Accounts Receivable, Net in the Consolidated Balance Sheets.

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

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

Energy Insurance Bermuda Ltd. Mutual Business Program No. 19

Energy Insurance Bermuda Ltd. ("EIB") is incorporated in Bermuda under the Companies Act of 1981, as amended. The Company began participating in EIB through Mutual Business Program No. 19 ("MBP 19") on November 15, 1998. The Company is the sole participant in MBP 19. In August 2002, the Company issued a $5.0 million standby letter of credit to MBP 19 for the benefit of insuring parts of the Company's property and liability insurance programs. In June 2003, the standby letter of credit was increased to $8.0 million. MBP 19 was established to provide $15.0 million worth of property and liability insurance for

the Company. The letter of credit was issued to provide protection for MBP 19 in the event of large insurance claim losses. At December 31, 2003, there were no drawings against this letter of credit. Because a letter of credit was issued, the total equity investment at risk of MBP 19 was not deemed sufficient to permit it to finance its activities without additional subordinated financial support from other parties. Therefore, MBP 19 was considered a variable interest entity ("VIE") as defined in Interpretation No. 46 and the Company was the primary beneficiary which resulted in the consolidation of MBP 19 into the Company's Consolidated Financial Statements for the year ended December 31, 2003. Effective January 1, 2004, the reinsurer of the MBP 19 program agreed to remove the guarantee requirement which enabled the Company to terminate the standby letter of credit previously provided. However, the reinsurer added a ratings trigger requirement in the revised agreement such that if the commercial paper rating of the Company is lowered by two grades, MBP 19 may be surcharged an additional premium, which may result in an additional premium to the Company. Because the guarantee requirement was removed, the total equity investment at risk of MBP 19 was deemed sufficient to permit it to finance its activities without additional subordinated financial support from other parties. Therefore, effective January 1, 2004, MBP 19 was not considered a VIE as defined in Interpretation No. 46 which resulted in the deconsolidation of MBP 19 during the first quarter of 2004. The Company plans to terminate the MBP 19 program during the first quarter of 2005 and does not expect the impact of terminating this program to have a material effect on the Company's consolidated financial position or results of operations.

OG&E Railcar Leases

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

Liquidity and Capital Requirements

The Company's primary needs for capital are related to replacing or expanding existing facilities in OG&E's electric utility business and replacing or expanding existing facilities (including technology) at Enogex. Other working capital requirements are primarily related to maturing debt, operating lease obligations, hedging activities, natural gas storage 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 (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
OG&E capital expenditures including AFUDC (A)	$ 647.7	$ 235.7	$ 412.0	N/A	N/A
Enogex capital expenditures and acquisitions	77.5	32.2	45.3	N/A	N/A
Other Operations capital expenditures	36.1	12.1	24.0	N/A	N/A
Total capital expenditures	761.3	280.0	481.3	N/A	N/A
Maturities of long-term debt	1,460.4	146.1	6.6	$ 4.6	$ 1,303.1
Interest payments on long-term debt	1,042.2	79.2	144.4	143.4	675.2
Pension funding obligations	123.8	37.4	61.3	25.1	N/A
Total capital requirements	3,387.7	542.7	693.6	173.1	1,978.3

Operating lease obligations

OG&E railcars	51.7	5.4	10.7	10.7	24.9
Enogex noncancellable operating leases	8.1	3.7	4.1	0.2	0.1
Total operating lease obligations	59.8	9.1	14.8	10.9	25.0
Other purchase obligations and commitments					
OG&E cogeneration capacity payments	465.6	99.5	194.2	171.9	N/A
OG&E fuel minimum purchase commitments	907.0	170.8	319.0	251.7	165.5
Other	75.7	7.4	14.9	14.9	38.5
Total other purchase obligations and commitments	1,488.3	277.7	528.1	438.5	204.0
Total capital requirements, operating lease obligations and other purchase obligations and commitments	4,895.8	829.5	1,236.5	622.5	2,207.3
Amounts recoverable through automatic fuel adjustment clause (B)	(1,424.3)	(275.7)	(523.9)	(434.3)	(190.4)
Total, net	$ 3,471.5	$ 553.8	$ 712.6	$ 188.2	$ 2,016.9

(A) Under current environmental laws and regulations, OG&E 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 OG&E's railcar operating lease obligations and OG&E'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 OG&E'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 OG&E'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 OG&E 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. OG&E currently has pending before the OCC an application to recover the costs of gas transportation and storage services provided to it by Enogex pursuant to the contract between OG&E and Enogex. An

adverse decision by the OCC could result in OG&E having to refund previously collected amounts. See Note 18 of Notes to Consolidated Financial Statements for a further discussion.

2004 Capital Requirements and Financing Activities

Total capital requirements, consisting of capital expenditures, maturities and retirements of long-term debt, interest payments on long-term debt and pension funding obligations, were approximately $840.0 million and contractual obligations, net of recoveries through automatic fuel adjustment clauses, were approximately $4.3 million resulting in total net capital requirements and contractual obligations of approximately $844.3 million in 2004. Approximately $7.8 million of the 2004 capital requirements were to comply with environmental regulations. This compares to net capital requirements of approximately $335.0 million and net contractual obligations of approximately $6.4 million totaling approximately $341.4 million in 2003, of which approximately $6.4 million was to comply with environmental regulations. During 2004, the Company's sources of capital were internally generated funds from operating cash flows, short-term borrowings (through a combination of bank borrowings and commercial paper), issuance of long-term debt, proceeds from the sale of assets and the issuance of common stock pursuant to the Company's DRIP/DSPP. The Company 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.

Early Retirement of Long-Term Debt

In 1998, Enogex issued a note in the amount of approximately $5.7 million payable to an unaffiliated former partial interest owner of NOARK. The note had a maturity date of July 1, 2020 and an interest rate of 7.00 percent. Principal and interest payments of approximately $0.8 million were due annually beginning July 1, 2004. In July 2004, Enogex made the initial $0.8 million payment and also made a payment of approximately $7.8 million, which included accrued interest since inception of the note, to repay the outstanding note balance and satisfy its remaining obligations related to this note. Enogex recorded a pre-tax gain of approximately $0.1 million in the third quarter of 2004 related to this transaction.

Asset Sales

Also contributing to the liquidity of the Company have been numerous asset sales by the Company. Since January 1, 2002, significant completed sales transactions have generated net sales proceeds of approximately $116.1 million. Sales proceeds generated to date have been used to reduce debt at Enogex and commercial paper at the holding company.

Additional asset sales could further contribute to the liquidity of the Company.

Issuance of Long-Term Debt

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

In September 2004, the Company filed a Form S-3 Registration Statement registering the sale of up to $200.0 million of the Company's unsecured debt securities. In November 2004, the Company issued $100.0 million of long-term debt, the proceeds of which were used to replace a portion of the short-term debt incurred to fund the redemption of the trust preferred securities on October 15, 2004. This new debt has a maturity date of November 15, 2014 and an interest rate of 5.00 percent.

Long-term Debt Maturities

During 2004 and 2003, approximately $51.0 million and $19.0 million, respectively, of Enogex's long-term debt matured and approximately $10.3 million and $12.0 million, respectively, was redeemed during 2004 and 2003 which is itemized in the following table.

(In millions)	**2004**	2003
Series Due 2003 -- 6.60% - 8.28%	**$ ---**	$ 19.0
Series Due 2004 -- 6.71% - 8.34%	**51.0**	---
Series Due 2018 -- 7.15%	**2.0**	2.0
Series Due 2020 -- 7.00%	**8.3**	---
Series Due 2023 -- 7.75%	---	10.0
Total	**$ 61.3**	$ 31.0

Maturities of the Company's long-term debt during the next five years consist of $146.1 million in 2005; $1.8 million in 2006; $4.8 million in 2007; $2.8 million in 2008 and $1.8 million in 2009. For OG&E, $110.0 million of long-term debt matures in 2005; however, in the Consolidated Statement of Capitalization at December 31, 2004, no amount is shown as Long-Term Debt Due Within One Year. The Company plans to refinance this amount and the Company believes they have the ability to do so as the Company and OG&E entered into new five-year revolving credit agreements in October 2004 in an amount up to $550 million which could be utilized to temporarily finance these notes when they mature in October 2005.

Interest Rate Swap Agreements

Fair Value Hedges

At December 31, 2004 and 2003, the Company had three outstanding interest rate swap agreements that qualified as fair value hedges: (i) OG&E entered into an interest rate swap agreement, effective March 30, 2001, to convert $110.0 million of 7.30 percent fixed rate debt due October 15, 2025, to a variable rate based on the three month London InterBank Offering Rate ("LIBOR") and (ii) Enogex entered into two separate interest rate swap agreements, effective July 15, 2002 and October 24, 2002, to convert a total of $200.0 million ($100.0

million for each interest rate swap agreement) of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the six month LIBOR in arrears. The objective of these interest rate swaps was to achieve a lower cost of debt and to raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standards. These interest rate swaps qualified as fair value hedges 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.

At December 31, 2004 and 2003, the fair values pursuant to the interest rate swaps were approximately $7.9 million and $7.6 million, respectively, and the hedges were classified as Deferred Charges and Other Assets – Price Risk Management in the Consolidated Balance Sheets. A corresponding net increase of approximately $7.9 million and $7.6 million was reflected in Long-Term Debt at December 31, 2004 and 2003, respectively, as these fair value hedges were effective at December 31, 2004 and 2003.

Cash Flow Hedges

The Company entered into four separate interest rate swap agreements, effective April 16, 2004, April 21, 2004, May 17, 2004 and July 16, 2004, respectively, to hedge approximately $20.0 million, $30.0 million, $20.0 million and $10.0 million, respectively, of future interest payments of long-term debt that was issued in November 2004. These interest rate swap agreements originally matured on October 15, 2004 but the maturity date was extended to November 8, 2004. The Company terminated these cash flow hedges on November 9, 2004, at which time approximately $4.0 million was recorded in other comprehensive income. This amount will be amortized to interest expense over the life of the related long-term debt.

Trust Originated Preferred Securities

On October 21, 1999, OGE Energy Capital Trust I, a wholly-owned financing trust of the Company, issued $200.0 million principal amount of 8.375 percent trust preferred securities with a maturity date of October 15, 2039. On October 15, 2004, the Company caused all of the outstanding trust preferred securities to be redeemed at $25 per share (100 percent of liquidation value). The redemption was initially funded with cash on hand and approximately $170.0 million in commercial paper. The Company refinanced a portion of this short-term debt with $100.0 million of long-term debt issued in November 2004. In October 2004, the Company wrote off approximately $5.9 million related to unamortized debt issuance costs for the trust preferred securities.

Future Capital Requirements

Capital Expenditures

The Company's current 2005 to 2007 construction program includes continued investment in system and transmission upgrades that is part of the Company's Customer Savings and Reliability Plan. OG&E has approximately 430 MWs of QF contracts that will expire at the end of 2007, unless extended by OG&E. In addition, effective September 1, 2004, OG&E

entered into a new 15-year power sales agreement for 120 MWs with PowerSmith. OG&E 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, OG&E 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, OG&E will also assess the feasibility of constructing additional base load coal-fired units. See Note 18 of Notes to Consolidated Financial Statements for a description of the new PowerSmith QF contract.

To reliably meet the increased electricity needs of OG&E's customers during the foreseeable future, OG&E will continue to invest to maintain the integrity of the delivery system. Approximately $7.0 million of the Company's capital expenditures budgeted for 2005 are to comply with environmental laws and regulations.

Pension and Postretirement Benefit Plans

During 2004, actual asset returns for the Company's defined benefit pension plan were positively affected by growth in the equity markets; however, the growth in 2004 was not as strong as the growth in the equity markets in 2003. Approximately 62 percent of the pension plan assets are invested in listed common stocks with the balance invested in corporate debt and U.S. Government securities. In 2004, asset returns on the pension plan were approximately 12.51 percent as compared to approximately 22.76 percent in 2003. During the same time, corporate bond yields, which are used in determining the discount rate for future pension obligations, have continued to decline.

Contributions to the pension plan increased from approximately $50.0 million in 2003 to approximately $69.0 million in 2004. This increase was necessitated by the lower investment returns on assets and lower discount rates used to value the accumulated pension benefit obligations. During 2005, the Company plans to contribute approximately $37.4 million to the pension plan. The level of funding is dependent on returns on plan assets and future discount rates. Higher returns on plan assets and increases in discount rates will reduce funding requirements to the plan.

As discussed in Note 15 of Notes to Consolidated Financial Statements, in 2000 the Company 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, the Company'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, the Company's cash requirements should decrease and will be much less sensitive to changes in discount rates.

During 2004 and 2003, the Company made contributions to the pension plan and the restoration of retirement income plan that exceeded amounts previously recognized as net

periodic pension expense and recorded a net prepaid benefit obligation at December 31, 2004 and 2003 of approximately $92.0 million and $55.7 million, respectively. At December 31, 2004 and 2003, the Company's projected pension benefit obligation exceeded the fair value of the pension plan assets and the restoration of retirement income plan assets by approximately $123.3 million and $131.8 million, respectively. As a result of recording a prepaid benefit obligation and having a funded status where the projected benefit obligations exceeded the fair value of plan assets, provisions of SFAS No. 87, "Employers' Accounting for Pensions," required the recognition of an additional minimum liability in the amount of approximately $156.6 million and $137.6 million, respectively, at December 31, 2004 and 2003. The offset of this entry was an intangible asset and Accumulated Other Comprehensive Income, net of a deferred tax asset; therefore, this adjustment did not impact the results of operations in 2004 or 2003 and did not require a usage of cash and is therefore excluded from the Consolidated 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 Consolidated Statements of Income in future periods.

Security Ratings

	Moody's	Standard & Poor's	Fitch's
OG&E Senior Notes	A2	BBB+	AA-
Enogex Notes	Baa3	BBB+	BBB
OGE Energy Corp. Senior Notes	Baa1	BBB	A
OGE Energy Corp. Commercial Paper	P-2	A-2	F1

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

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

Future Sources of Financing

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

Short-Term Debt

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

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

Entity	Amount Available	Amount Outstanding	Maturity
OGE Energy Corp.	$ 15.0	$ ---	April 6, 2004
OG&E	100.0	---	October 20, 2009 (B)
OGE Energy Corp. (A)	450.0	---	October 20, 2009 (B)
	565.0	---	
Cash	14.9	N/A	N/A
Total	$ 579.9	$ ---	

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

On October 20, 2004, the Company and OG&E entered into revolving credit agreements totaling $550 million. These agreements include two separate credit facilities, one for the Company in an amount up to $450 million and one for OG&E in an amount up to $100 million. Each of the new credit facilities has a five-year term with two options to extend the term for one year. Planned uses of the revolving credit include working capital needs, back-up for the Company's commercial paper program, the issuance of letters of credit and for general corporate purposes.

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

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

Critical Accounting Policies and Estimates

The Consolidated Financial Statements and Notes to Consolidated Financial Statements contain information that is pertinent to Management's Discussion and Analysis. In preparing the Consolidated Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Consolidated Financial Statements and the reported

amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material affect on the Company's Consolidated Financial Statements particularly as they relate to pension expense and impairment estimates. 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, impairment estimates, contingency reserves, accrued removal obligations, regulatory assets and liabilities, unbilled revenue for OG&E, the allowance for uncollectible accounts receivable, the valuation of energy purchase and sale contracts and natural gas storage inventory 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.

Consolidated (including Electric Utility and Natural Gas Pipeline Segments)

Pension and other postretirement plan expenses and liabilities are determined on an actuarial basis and are affected by the market value of plan assets, estimates of the expected return on plan assets, 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 15 of Notes to Consolidated Financial Statements. The assumed return on plan assets is based on management's expectation of the long-term return on the plan assets portfolio. The discount rate used to compute the present value of plan liabilities is based generally on rates of high-grade corporate bonds with maturities similar to the average period over which benefits will be paid. The level of funding is dependent on returns on plan assets and future discount rates. Higher returns on plan assets and increases in discount rates will reduce funding requirements to the plan. The following table indicates the sensitivity of the pension plans funded status to these variables.

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

The Company assesses potential impairments of assets or asset groups when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset or asset group. For purposes of recognition and measurement of an impairment loss, a long-lived asset or assets shall be grouped with other assets and liabilities at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. Estimates of future cash flows used to test the recoverability of a long-lived asset or asset group shall include only the future cash flows (cash inflows less associated cash outflows) that are directly associated with and that are expected to arise as a direct result of the use and eventual disposition of the asset or asset group. The fair value of these assets is based on third-party evaluations, prices for similar assets, historical data and projected cash flow. An

impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset. Enogex expects to continue to evaluate the strategic fit and financial performance of each of its assets in an effort to ensure a proper economic allocation of resources. The magnitude and timing of any potential impairment or gain on the disposition of any assets have not been determined or included in the 2005 earnings guidance.

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

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

The Company expects that the FASB will issue an interpretation related to SFAS No. 143 during the first quarter of 2005 in which an entity would be required to recognize a liability for the fair value of an asset retirement obligation that is conditional on a future event if the liability's fair value can be reasonably estimated. The fair value of a liability for the conditional asset retirement obligation would be recognized when incurred. Uncertainty surrounding the timing and method of settlement that may be conditional on events occurring in the future would be factored into the measurement of the liability rather than the recognition of the liability. However, in some cases, there is insufficient information to estimate the fair value of an asset retirement obligation. In these cases, the liability would be initially recognized in the period in

which sufficient information is available for an entity to make a reasonable estimate of the liability's fair value. The Company expects that this interpretation will be effective no later than the end of fiscal years ending after December 15, 2005. Additionally, the interpretation is expected to permit, but not require, restatement of interim financial information during any period of adoption. The FASB also has indicated that it will require both recognition of a cumulative change in accounting principle and disclosure of the liability on a pro forma basis for transition purposes. The Company will evaluate the financial impact when a final interpretation is issued.

OG&E and Enogex engage in cash flow and fair value hedge transactions to manage commodity risk and modify the rate composition of the debt portfolio. Enogex may hedge its forward exposure to manage changes in commodity prices. Anticipated transactions are documented as cash flow hedges pursuant to SFAS No. 133 hedging requirements and are executed based upon management established price targets. During 2003, OERI also utilized fair value hedges under SFAS No. 133 to manage commodity price exposure for natural gas storage inventory. However, during 2004, OERI decided not to utilize hedge accounting under SFAS No. 133 for natural gas storage inventory. Hedges are evaluated prior to execution with respect to the impact on the volatility of forecasted earnings and are evaluated at least quarterly after execution for the impact on earnings. OG&E and Enogex have entered into interest rate swap agreements on the debt portfolio to modify the interest rate exposure on fixed rate debt issues. These interest rate swaps qualify as fair value hedges under SFAS No. 133. The objective of these interest rate swaps was to achieve a lower cost of debt and to raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standards.

Electric Utility Segment

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

OG&E 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.

OG&E reads its customers' meters and sends bills to its customers throughout each month. As a result, there is a significant amount of customers' electricity consumption that has not been billed at the end of each month. Unbilled revenue is presented in Accrued Unbilled Revenues on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated

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

December 31, 2004 and 2003, Accrued Unbilled Revenues were approximately $45.5 million and $38.0 million, respectively. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

Customer balances are generally written off if not collected within six months after the original due date. The allowance for uncollectible accounts receivable is calculated by multiplying the last six months of electric revenue by the provision rate. The provision rate is based on a 12-month historical average of actual balances written off. To the extent the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. At December 31, 2004, if the provision rate were to increase or decrease by 10 percent, this would cause a change in the uncollectible expense recognized of approximately $0.3 million. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Consolidated Balance Sheets and is included in Other Operation and Maintenance Expense on the Consolidated Statements of Income. The allowance for uncollectible accounts receivable was approximately $2.7 million and $2.6 million at December 31, 2004 and 2003, respectively.

Natural Gas Pipeline Segment

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

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

OERI's activities include the marketing of natural gas and natural gas liquids. The vast majority of these contracts expire within three years, which is when the cash aspect of the transactions will be realized. A substantial portion of these contracts qualify as derivatives under SFAS No. 133 and are marked-to-market with offsetting gains and losses recorded in earnings. In nearly all cases, independent market prices are obtained and compared to the values used for this mark-to-market valuation, and an oversight group outside of the marketing organization monitors all modeling methodologies and assumptions. The recorded value of the energy contracts may change significantly in the future as the market price for the commodity changes, but the value is still subject to the risk loss limitations provided under the Company's risk

policies. The Company utilizes a model to estimate the fair value of its energy contracts including derivatives that do not have an independent market price. At December 31, 2004, unrealized mark-to-market gains were approximately $20.7 million, which included approximately $0.4 million of unrealized mark-to-market gains that were calculated utilizing models. At December 31, 2004, a price movement of one percent for prices verified by independent parties would result in changes in unrealized mark-to-market gains of approximately $0.1 million and a price movement of five percent on model-based prices would result in changes in unrealized mark-to-market gains of approximately $0.1 million. Energy contracts are presented in Price Risk Management assets and liabilities on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income. See Note 2 of Notes to Consolidated Financial Statements for a further discussion of accounting for energy contracts.

Effective January 1, 2003, natural gas storage inventory used in OERI's business activities are accounted for at the lower of cost or market in accordance with the guidance in EITF 02-3 which resulted in the rescission of EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," as amended. Prior to January 1, 2003, this inventory was accounted for on a fair value accounting basis utilizing a gas index that in management's opinion approximated the current market value of natural gas in that region as of the Balance Sheet date. On April 1, 2003, natural gas storage inventory used in OERI's business activities began to be accounted for under SFAS No. 133. In order to minimize risk, OERI enters into contracts or hedging instruments to hedge the fair value of this inventory. For any contracts that qualify for hedge accounting under SFAS No. 133, the hedged portion of the inventory is recorded at fair value with an offsetting gain or loss recorded currently in earnings. During 2003, OERI utilized hedge accounting under SFAS No. 133 for natural gas storage inventory; however, during 2004, OERI decided not to utilize hedge accounting under SFAS No. 133 for natural gas storage inventory. Ineffectiveness associated with OERI's fair value hedge strategy was not material. The fair value of the hedging instrument is also recorded on the books of OERI as a Price Risk Management asset or liability with an offsetting gain or loss recorded in current earnings. As part of its recurring business activity, OERI injects and withdraws natural gas under the terms of storage capacity contracts; the amount of natural gas inventory was approximately $29.0 million and $82.4 million at December 31, 2004 and 2003, respectively. See Note 2 of Notes to Consolidated Financial Statements for a further discussion. Natural gas storage inventory is presented in Fuel Inventories on the Consolidated Balance Sheets and in Cost of Goods Sold on the Consolidated Statements of Income.

The allowance for uncollectible accounts receivable is calculated based on outstanding accounts receivable balances over 180 days old. In addition, other outstanding accounts receivable balances less than 180 days old are reserved on a case-by-case basis when the Company believes the required payment of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Consolidated Balance Sheets and is included in Other Operation and Maintenance Expense on the Consolidated Statements of Income. The allowance for uncollectible accounts receivable for the Natural Gas Pipeline segment was approximately $1.8 million and $1.6 million at December 31, 2004 and 2003, respectively.

Accounting Pronouncements

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

Electric Competition; Regulation

OG&E and Enogex 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 are being proposed to the wholesale electric market. Although it appears unlikely in the near future that changes will occur to retail regulation in the states served by OG&E due to the significant problems faced by California in its electric deregulation efforts and other factors, significant changes are possible, which could significantly change the manner in which OG&E conducts its business. These developments at the federal and state levels are described in more detail in Note 18 of Notes to Consolidated Financial Statements. OG&E currently has one important matter pending before the OCC. See Note 18 of Notes of Consolidated Financial Statements for a further discussion.

Commitments and Contingencies

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies. Management consults with counsel and other appropriate experts to assess the claim. If in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. Management, after consultation with legal counsel, does not anticipate that liabilities arising out of currently pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows. This assessment of currently pending or threatened lawsuits is subject to change. See Note 17 of Notes to Consolidated Financial Statements for a discussion of the Company's commitments and contingencies.

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

Risk Management

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

To manage the volatility relating to these exposures, the Company enters into various derivative and other forward transactions pursuant to the Company's policies on hedging practices. These positions are monitored using techniques such as mark-to-market valuation, value-at-risk and sensitivity analysis.

Interest Rate Risk

The Company's exposure to changes in interest rates relates primarily to long-term debt obligations and commercial paper. The Company manages its interest rate exposure by limiting its variable rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. The Company utilizes interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Fair Value Hedges

At December 31, 2004 and 2003, the Company had three outstanding interest rate swap agreements that qualified as fair value hedges: (i) OG&E entered into an interest rate swap agreement, effective March 30, 2001, to convert $110.0 million of 7.30 percent fixed rate debt due October 15, 2025, to a variable rate based on the three month LIBOR and (ii) Enogex entered into two separate interest rate swap agreements, effective July 15, 2002 and October 24, 2002, to convert a total of $200.0 million ($100.0 million for each interest rate swap agreement) of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the six month LIBOR in arrears. The objective of these interest rate swaps was to achieve a lower cost of debt and to raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standards. These interest rate swaps qualified as fair value hedges 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.

At December 31, 2004 and 2003, the fair values pursuant to the interest rate swaps were approximately $7.9 million and $7.6 million, respectively, and the hedges were classified as Deferred Charges and Other Assets – Price Risk Management in the Consolidated Balance Sheets. A corresponding net increase of approximately $7.9 million and $7.6 million was

reflected in Long-Term Debt at December 31, 2004 and 2003, respectively, as these fair value hedges were effective at December 31, 2004 and 2003.

Cash Flow Hedges

The Company entered into four separate interest rate swap agreements, effective April 16, 2004, April 21, 2004, May 17, 2004 and July 16, 2004, respectively, to hedge approximately $20.0 million, $30.0 million, $20.0 million and $10.0 million, respectively, of future interest payments of long-term debt that was issued in November 2004. These interest rate swap agreements originally matured on October 15, 2004 but the maturity date was extended to November 8, 2004. The Company terminated these cash flow hedges on November 9, 2004, at which time approximately $4.0 million was recorded in other comprehensive income. This amount will be amortized to interest expense over the life of the related long-term debt.

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

(Dollars in millions)	2005	2006	2007	2008	2009	Thereafter	Total	12/31/04 Fair Value
Fixed rate debt								
Principal amount	$ 146.1	$ 1.8	$ 4.8	$ 2.8	$ 1.8	$ 845.5	$ 1,002.8	$ 1,097.6
Weighted-average interest rate	7.07%	7.15%	7.83%	7.12%	7.15%	6.77%	6.82%	---
Variable rate debt								
Principal amount (A)	---	---	---	---	---	$ 457.6	$ 457.6	$ 458.2
Weighted-average interest rate	---	---	---	---	---	3.45%	3.45%	---

(A) Amount includes an increase to the fair value of long-term debt of approximately $7.9 million due to the Company's interest rate swaps.

Commodity Price Risk

The market risks inherent in the Company's market risk sensitive instruments, positions and anticipated commodity transactions are the potential losses in value arising from adverse changes in the commodity prices to which the Company is exposed. These market risks can be classified as trading, which includes transactions that are entered into voluntarily to capture subsequent changes in commodity prices, or non-trading, which includes the exposure some of the Company's assets have to commodity prices.

The trading activities are conducted throughout the year subject to daily and monthly trading stop loss limits of $2.5 million. The daily loss exposure from trading activities is measured primarily using value at risk, subject to a $1.5 million limit, as well as other quantitative risk measurement techniques. These limits are designed to mitigate the possibility of trading activities having a material adverse effect on the Company's operating income.

The prices of natural gas, natural gas liquids and natural gas liquids processing spreads are subject to fluctuations resulting from changes in supply and demand. The changes in these prices have a direct effect on the operating income received by the Company as compensation for operating some of its assets. To partially reduce non-trading commodity price risk incurred in the Company's normal course of business caused by these market fluctuations, the Company hedges, through the utilization of derivatives and other forward transactions, the effects these market fluctuations have on the operating income received by the Company as compensation for operating these assets. Because the commodities covered by these hedges are substantially the same commodities that the Company buys and sells in the physical market, no special studies other than monitoring the degree of correlation between the derivative and cash markets are deemed necessary.

Sensitivity analyses have been prepared to estimate the Company's exposure to the market risk of the Company's natural gas and natural gas liquids commodity positions. These analyses are done for both trading and non-trading activities. The Company's daily net commodity position consists of natural gas inventories, commodity purchase and sales contracts, financial and commodity derivative instruments and anticipated natural gas processing spreads and fuel recoveries. The value of trading positions is a summation of the fair values calculated for each commodity by valuing each net position at quoted market prices. Because quoted market prices are not available for all of the Company's non-trading positions, the value of non-trading positions is a summation of the forecasted values calculated for each commodity based upon internally generated forecast prices. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 10 percent adverse change in such prices over the next 12 months. The results of these analyses, which may differ from actual results, are as follows for 2004.

(In millions)	Trading	Non-Trading
Commodity market risk, net	$ 0.3	$ 7.8

Item 8. Financial Statements and Supplementary Data.

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS

December 31 *(In millions)*	**2004**	2003
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 26.4**	$ 245.6
Accounts receivable, net	**487.9**	350.2
Accrued unbilled revenues	**45.5**	38.0
Fuel inventories	**89.0**	149.6
Materials and supplies, at average cost	**53.2**	45.1
Price risk management	**118.6**	61.3
Gas imbalances	**100.1**	70.0
Accumulated deferred tax assets	**13.7**	9.4
Fuel clause under recoveries	**54.3**	4.0
Recoverable take or pay gas charges	**17.0**	---
Other	**13.5**	21.5
Total current assets	**1,019.2**	994.7
OTHER PROPERTY AND INVESTMENTS, at cost	**31.4**	34.7
PROPERTY, PLANT AND EQUIPMENT		
In service	**5,957.6**	5,610.0
Construction work in progress	**110.5**	56.7
Other	**5.8**	15.0
Total property, plant and equipment	**6,073.9**	5,681.7
Less accumulated depreciation	**2,492.9**	2,358.5
Net property, plant and equipment	**3,581.0**	3,323.2

DEFERRED CHARGES AND OTHER ASSETS		
Recoverable take or pay gas charges	---	32.5
Income taxes recoverable from customers, net	**30.9**	31.6
Intangible asset - unamortized prior service cost	**38.0**	40.2
Prepaid benefit obligation	**92.7**	55.7
Price risk management	**19.6**	13.5
Other	**57.5**	58.6
Total deferred charges and other assets	**238.7**	232.1
TOTAL ASSETS	**$4,870.3**	$4,584.7

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

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS (Continued)

December 31 *(In millions)*	**2004**	2003
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 125.0**	$ 202.5
Accounts payable	**476.2**	280.2
Dividends payable	**29.9**	29.1
Customers' deposits	**48.3**	41.6
Accrued taxes	**14.1**	18.7
Accrued interest	**33.2**	30.7
Accrued interest - unconsolidated affiliate	---	3.5
Tax collections payable	**7.2**	7.9
Accrued vacation	**17.9**	17.2
Long-term debt due within one year	**35.1**	52.1
Non-recourse debt of joint venture	**1.2**	1.2
Price risk management	**102.9**	46.9
Gas imbalances	**22.8**	22.5
Fuel clause over recoveries	---	32.4
Provision for payments of take or pay gas	**21.0**	---
Other	**40.6**	41.2
Total current liabilities	**975.4**	827.7
LONG-TERM DEBT		
Long-term debt	**1,385.1**	1,189.7
Non-recourse debt of joint venture	**39.0**	40.2
Long-term debt - unconsolidated affiliate	---	206.2
Total long-term debt	**1,424.1**	1,436.1
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued pension and benefit obligations	**197.0**	167.4
Accumulated deferred income taxes	**802.0**	747.3
Accumulated deferred investment tax credits	**36.8**	42.0
Accrued removal obligations, net	**122.2**	116.3
Price risk management	**6.6**	4.5
Provision for payments of take or pay gas	---	32.5
Asset retirement obligation	**1.1**	---
Other	**19.5**	9.3
Total deferred credits and other liabilities	**1,185.2**	1,119.3
STOCKHOLDERS' EQUITY		
Common stockholders' equity	**700.8**	636.1
Retained earnings	**659.8**	623.9
Accumulated other comprehensive loss, net of tax	**(75.0)**	(58.4)
Total stockholders' equity	**1,285.6**	1,201.6
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$4,870.3**	$4,584.7

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 *(In millions)*		**2004**	2003
STOCKHOLDERS' EQUITY			
Common stock, par value $0.01 per share; authorized 125.0 shares; and outstanding 90.0 and 87.4 shares, respectively		**$ 0.9**	$ 0.9
Premium on capital stock		**699.9**	635.2
Retained earnings		**659.8**	623.9
Accumulated other comprehensive loss, net of tax		**(75.0)**	(58.4)
Total stockholders' equity		**1,285.6**	1,201.6
LONG-TERM DEBT			
SERIES	DATE DUE		
Senior Notes-OGE Energy Corp.			
5.00 %	Senior Notes, Series Due November 15, 2014	**100.0**	---
Unamortized discount		**(0.9)**	---
Senior Notes-OG&E			
7.125 %	Senior Notes, Series Due October 15, 2005	**110.0**	110.0
6.50 %	Senior Notes, Series Due July 15, 2017	**125.0**	125.0
Variable %	Senior Notes, Series Due October 15, 2025	**114.0**	114.0
6.65 %	Senior Notes, Series Due July 15, 2027	**125.0**	125.0
6.50 %	Senior Notes, Series Due April 15, 2028	**100.0**	100.0
6.50 %	Senior Notes, Series Due August 1, 2034	**140.0**	---
Other bonds-OG&E			
Variable %	Garfield Industrial Authority, January 1, 2025	**47.0**	47.0
Variable %	Muskogee Industrial Authority, January 1, 2025	**32.4**	32.4
Variable %	Muskogee Industrial Authority, June 1, 2027	**56.0**	56.0
Unamortized discount		**(2.2)**	(2.2)
Enogex Notes			
6.71% - 8.34%	Medium-Term Notes, Series Due 2004	---	51.0
6.81% - 6.99%	Medium-Term Notes, Series Due 2005	**34.3**	34.2
8.28%	Medium-Term Notes, Series Due 2007	**3.0**	3.0
7.07%	Medium-Term Notes, Series Due 2008	**1.0**	1.0
8.125%	Medium-Term Notes, Series Due 2010	**200.0**	200.0
Variable %	Medium-Term Notes, Series Due 2010	**208.8**	209.5
7.15%	Medium-Term Notes, Series Due 2018	**67.0**	69.0
7.00%	Medium-Term Notes, Series Due 2020	---	8.3
Unconsolidated affiliate (Note 12)		---	206.2
Total long-term debt		**1,460.4**	1,489.4
Less long-term debt due within one year		**35.1**	52.1
Non-recourse of joint venture		**1.2**	1.2
Total long-term debt (excluding long-term debt due within one year)		**1,424.1**	1,436.1
Total Capitalization		**$2,709.7**	$2,637.7

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

Year ended December 31 *(In millions, except per share data)*	**2004**	2003	2002
OPERATING REVENUES			
Electric Utility operating revenues	**$1,578.1**	$1,517.1	$1,388.0
Natural Gas Pipeline operating revenues	**3,348.5**	2,261.9	1,635.9
Total operating revenues	**4,926.6**	3,779.0	3,023.9
COST OF GOODS SOLD			
Electric Utility cost of goods sold	**865.0**	792.7	662.2

Natural Gas Pipeline cost of goods sold	**3,097.7**	2,053.3	1,458.1
Total cost of goods sold	**3,962.7**	2,846.0	2,120.3
Gross margin on revenues	**963.9**	933.0	903.6
Other operation and maintenance	**392.2**	371.7	370.0
Depreciation	**178.6**	176.9	182.5
Impairment of assets	**7.8**	10.2	50.1
Taxes other than income	**67.8**	67.3	65.3
OPERATING INCOME	**317.5**	306.9	235.7
OTHER INCOME (EXPENSE)			
Other income	**12.1**	8.1	3.7
Other expense	**(5.5)**	(9.0)	(4.7)
Net other income (expense)	**6.6**	(0.9)	(1.0)
INTEREST INCOME (EXPENSE)			
Interest income	**5.2**	1.3	1.7
Interest on long-term debt	**(74.4)**	(75.2)	(86.2)
Interest on trust preferred securities	**---**	---	(17.3)
Interest expense - unconsolidated affiliate	**(13.7)**	(17.3)	---
Allowance for borrowed funds used during construction	**1.7**	0.5	0.9
Interest on short-term debt and other interest charges	**(9.7)**	(6.0)	(8.2)
Net interest expense	**(90.9)**	(96.7)	(109.1)
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	**233.2**	209.3	125.6
INCOME TAX EXPENSE	**80.2**	73.7	44.6
INCOME FROM CONTINUING OPERATIONS BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	**153.0**	135.6	81.0
DISCONTINUED OPERATIONS (NOTE 4)			
Income from discontinued operations	**0.8**	1.8	8.4
Income tax expense (benefit)	**0.3**	2.2	(1.4)
Income (loss) from discontinued operations	**0.5**	(0.4)	9.8
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	**153.5**	135.2	90.8
CUMULATIVE EFFECT ON PRIOR YEARS OF CHANGE IN ACCOUNTING PRINCIPLE, net of tax of $3.4	**---**	(5.4)	---
NET INCOME	**$ 153.5**	$ 129.8	$ 90.8
BASIC AVERAGE COMMON SHARES OUTSTANDING	**88.0**	81.8	78.1
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**88.5**	82.1	78.2
BASIC EARNINGS (LOSS) PER AVERAGE COMMON SHARE			
Income from continuing operations	**$ 1.73**	$ 1.66	$ 1.04
Income from discontinued operations, net of tax	**0.01**	---	0.12
Loss from cumulative effect of accounting change, net of tax	**---**	(0.07)	---
NET INCOME	**$ 1.74**	$ 1.59	$ 1.16
DILUTED EARNINGS (LOSS) PER AVERAGE COMMON SHARE			
Income from continuing operations	**$ 1.72**	$ 1.65	$ 1.04
Income from discontinued operations, net of tax	**0.01**	---	0.12
Loss from cumulative effect of accounting change, net of tax	**---**	(0.07)	---
NET INCOME	**$ 1.73**	$ 1.58	$ 1.16
DIVIDENDS DECLARED PER SHARE	**$ 1.33**	$ 1.33	$ 1.33

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Year ended December 31 *(In millions)*	**2004**	2003	2002

BALANCE AT BEGINNING OF PERIOD	**$ 623.9**	$ 604.7	$ 617.9
ADD: Net income	**153.5**	129.8	90.8
Total	**777.4**	734.5	708.7
DEDUCT: Dividends declared on common stock	**117.6**	110.6	104.0
BALANCE AT END OF PERIOD	**$ 659.8**	$ 623.9	$ 604.7

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31 *(In millions)*	**2004**	2003	2002
Net income	**$ 153.5**	$ 129.8	$ 90.8
Other comprehensive income (loss), net of tax:			
Minimum pension liability adjustment [($21.2), $23.8 and ($85.5) pre-tax, respectively]	**(13.0)**	14.6	(52.4)
Reclassification adjustments - contract settlements [$0.2 pre-tax]	---	---	0.1
Deferred hedging gains (losses) [($1.1) and $1.5 pre-tax, respectively]	**(0.7)**	0.9	---
(Reversal of unrealized gain) unrealized gains on available-for-sale securities [($0.6) and $0.6 pre-tax, respectively]	**(0.4)**	0.4	---
Settlement of cash flow hedge [($4.0) pre-tax]	**(2.5)**	---	---
Total other comprehensive income (loss), net of tax	**(16.6)**	15.9	(52.3)
Total comprehensive income	**$ 136.9**	$ 145.7	$ 38.5

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 *(In millions)*	**2004**	2003	2002
CASH FLOWS FROM OPERATING ACTIVITIES			
Net Income	**$ 153.5**	$ 129.8	$ 90.8
Adjustments to reconcile net income to net cash provided from operating activities			
(Income) loss from discontinued operations	**(0.5)**	0.4	(9.8)
Cumulative effect of change in accounting principle	---	5.4	---
Depreciation	**178.6**	176.9	182.5
Impairment of assets	**7.8**	10.2	50.1
Deferred income taxes and investment tax credits, net	**53.1**	116.3	33.1
Allowance for equity funds used during construction	**(0.9)**	---	---
Gain on sale of assets	**(6.5)**	(6.1)	(1.0)
Ineffectiveness of interest rate swap	---	---	0.2
Price risk management assets	**(63.1)**	(45.8)	4.8
Price risk management liabilities	**52.5**	36.7	16.4
Other assets	**(27.2)**	(6.7)	(36.8)
Other liabilities	**11.0**	0.8	(8.6)
Change in certain current assets and liabilities			
Accounts receivable, net	**(137.7)**	(45.6)	(83.5)
Accrued unbilled revenues	**(7.5)**	(9.8)	7.4
Fuel, materials and supplies inventories	**52.5**	(54.8)	(26.5)
Gas imbalances asset	**(30.1)**	(22.3)	(32.4)
Fuel clause under recoveries	**(50.3)**	10.7	(14.7)
Other current assets	**3.5**	(2.3)	(1.1)
Accounts payable	**196.0**	18.5	108.5
Customers' deposits	**6.7**	1.0	12.1
Accrued taxes	**(4.6)**	(1.6)	(4.8)

Accrued interest	**(1.0)**	(1.4)	(4.2)
Fuel clause over recoveries	**(32.4)**	32.4	(23.4)
Gas imbalances liability	**0.3**	(0.3)	16.3
Other current liabilities	**5.8**	19.4	7.9
Net Cash Provided from Operating Activities	**359.5**	361.8	283.3
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures (less allowance for equity funds used during construction)	**(431.8)**	(181.3)	(234.5)
Proceeds from sale of assets	**9.3**	16.2	1.7
Other investing activities	**0.7**	1.6	(0.5)
Net Cash Used in Investing Activities	**(421.8)**	(163.5)	(233.3)
CASH FLOWS FROM FINANCING ACTIVITIES			
Retirement of long-term debt	**(267.4)**	(31.0)	(140.0)
(Decrease) increase in short-term debt, net	**(77.5)**	(72.5)	126.2
Proceeds from long-term debt	**237.0**	---	---
Premium on issuance of common stock	**62.5**	171.3	3.1
Distribution from (to) minority interest	**2.6**	(2.5)	---
Dividends paid on common stock	**(114.6)**	(98.6)	(99.5)
Net Cash Used in Financing Activities	**(157.4)**	(33.3)	(110.2)
DISCONTINUED OPERATIONS			
Net cash provided from (used in) operating activities	**0.5**	(1.9)	17.2
Net cash provided from investing activities	---	38.1	51.3
Net cash used in financing activities	---	---	(1.4)
Net Cash Provided from Discontinued Operations	**0.5**	36.2	67.1
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	**(219.2)**	201.2	6.9
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**245.6**	44.4	37.5
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 26.4**	$ 245.6	$ 44.4

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

OGE ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Organization

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

The Electric Utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through Oklahoma Gas and Electric Company (“OG&E”) and are subject to regulation by the Oklahoma Corporation Commission (“OCC”), the Arkansas Public Service Commission (“APSC”) and the Federal Energy Regulatory Commission (“FERC”). OG&E was incorporated in 1902 under the laws of the Oklahoma Territory and is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. OG&E sold its retail gas business in 1928 and is no longer engaged in the gas distribution business.

The operations of the Natural Gas Pipeline segment are conducted through Enogex Inc. and its subsidiaries (“Enogex”) and consist of three related businesses: (i) the transportation and storage of natural gas, (ii) the gathering and processing of natural gas and (iii) the marketing of natural gas. The vast majority of Enogex’s natural gas gathering, processing, transportation and storage assets are located in the major gas producing basins of Oklahoma. Through a 75 percent interest in the NOARK Pipeline System Limited Partnership (“NOARK”), Enogex also owns a controlling interest in and operates Ozark Gas Transmission, L.L.C. (“Ozark”), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. Enogex was previously engaged in the exploration and production of natural gas, however, this portion of Enogex’s business, along with interests in certain gas gathering and processing assets in Texas, was sold in 2002 and in the first quarter of 2003 and are reported in the Consolidated Financial Statements as discontinued operations. During the third quarter of 2004, Enogex entered into a joint venture arrangement with a third party and contributed certain of its natural gas compression assets to use in the joint venture, whose primary business focus will be the rental of compression assets. Enogex created a wholly-owned limited liability company, Enogex Compression Company, LLC (“Enogex Compression”), to act as the participating entity in the joint venture. Enogex Compression holds a majority ownership in the joint venture and the third party acts as the manager and conducts the daily operations of the joint venture. Enogex Compression has been consolidated in the Company’s financial statements with a minority interest recorded.

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

Accounting Records

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

OG&E 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 OG&E’s regulatory assets and liabilities at December 31:

(In millions)	**2004**	2003
Regulatory Assets		
Fuel clause under recoveries	**$ 54.3**	$ 4.0
Recoverable take or pay gas charges	**17.0**	32.5
Income taxes recoverable from customers, net	**30.9**	31.6
Unamortized loss on reacquired debt	**21.0**	22.1
McClain Plant expenses	**11.0**	---
January 2002 ice storm	**1.8**	3.6
Arkansas transition costs	**0.7**	---
Miscellaneous	**0.6**	0.4
Total Regulatory Assets	**$ 137.3**	$ 94.2
Regulatory Liabilities		
Accrued removal obligations, net	**$ 122.2**	$ 116.3
Estimated refund on gas transportation and storage case	**6.9**	---
Estimated refund on FERC fuel	**1.0**	1.0
Fuel clause over recoveries	**---**	32.4
Total Regulatory Liabilities	**$ 130.1**	$ 149.7

Fuel clause under recoveries are generated from under recoveries from OG&E’s customers when OG&E’s cost of fuel exceeds the amount billed to its customers. Fuel clause over recoveries are generated from over recoveries from OG&E’s customers when the amount billed to its customers exceeds OG&E’s cost of fuel. OG&E’s fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers’ bills. As a result, OG&E 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 OG&E to amortize under or over recovery. OG&E expects to recover the fuel clause under recoveries during 2005.

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

Income taxes recoverable from customers represent income tax benefits previously used to reduce OG&E’s revenues. These amounts are being recovered in rates as the temporary differences that generated the income tax benefit turn around. The provisions of SFAS No. 71 allowed OG&E 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 Consolidated Balance Sheets in the line item, “Income Taxes Recoverable from Customers, Net.”

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

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

On November 22, 2002, the OCC signed a rate order containing the provisions of a Settlement Agreement of OG&E’s rate case. The Settlement Agreement provides for, among other things, recovery by OG&E, over three years, of the $5.4 million in deferred operating costs, associated with the January 2002 ice storm, through OG&E's rider for sales to other utilities and power marketers ("off-system sales"). Previously, OG&E 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 OG&E's off-system sales will go to OG&E, the next $3.6 million in annual net profits from off-system sales will go to OG&E's Oklahoma customers, and any net profits of off-system sales in excess of these amounts will be credited in each sales

year with 80 percent to OG&E's Oklahoma customers and the remaining 20 percent to OG&E. If any of the $5.4 million is not recovered at the end of the three years, the OCC will authorize the recovery of any remaining costs. During the year ended December 31, 2004, OG&E recovered approximately $1.8 million in annual net profits from off-system sales, gave approximately $3.6 million in annual net profits from off-system sales to OG&E's Oklahoma customers and the net profits from off-system sales that exceeded the $5.4 million were shared with 80 percent to OG&E's Oklahoma customers and the remaining 20 percent to OG&E.

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. OG&E 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 OG&E to recover approximately $1.9 million in transition costs over an 18-month period beginning February 2004.

Accrued removal obligations represent asset retirement costs previously recovered from ratepayers for other than legal obligations. In accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations," OG&E was required to reclassify its accrued removal obligations, which had previously been recorded as a liability in Accumulated Depreciation, to a regulatory liability.

On November 22, 2002, the OCC signed a rate order containing the provisions of the Settlement Agreement of OG&E's rate case. As part of the Settlement Agreement, OG&E agreed to consider competitive bidding as a basis to select its provider for gas transportation service to its natural gas-fired generation facilities pursuant to the terms set forth in the Settlement Agreement. The prescribed bidding process detailed in the Settlement Agreement provided that each generation facility seek bids separately for the services required. OG&E believes that in order for it to achieve maximum coal generation, deliver the lowest cost energy to its customers and ensure reliable electric service, it must have integrated, firm no-notice load following service for both gas transportation and gas storage. On April 29, 2003, as required by the Settlement Agreement, OG&E filed an application with the OCC in which OG&E advised the OCC that, after careful consideration, competitive bidding for gas transportation was rejected in favor of a new intrastate integrated, firm no-notice load following gas transportation and storage services agreement with Enogex. On October 22, 2004, the administrative law judge overseeing the proceeding recommended approximately $41.9 million annual demand fee recovery with OG&E refunding to its customers any demand fees collected in excess of this amount. If this recommendation is ultimately accepted, OG&E believes its refund obligation would be approximately $6.9 million at December 31, 2004, which the Company does not believe is material in light of previously established reserves. See Note 18 for a further discussion.

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

application of SFAS No. 71 for some or all of its operations, it could result in writing off the related regulatory assets; the financial effects of which could be significant.

Use of Estimates

In preparing the Consolidated Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material affect on the Company's Consolidated Financial Statements particularly as they relate to pension expense and impairment estimates. 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, impairment estimates, contingency reserves, accrued removal obligations, regulatory assets and liabilities, unbilled revenue for OG&E, the allowance for uncollectible accounts receivable, the valuation of energy purchase and sale contracts and natural gas storage inventory and fair value and cash flow hedging policies.

Cash and Cash Equivalents

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

The Company's cash management program utilizes controlled disbursement banking arrangements. Outstanding checks in excess of cash balances were approximately $33.9 million and $38.7 million at December 31, 2004 and 2003, respectively, and are classified as Accounts Payable in the Consolidated Balance Sheets. Sufficient funds were available to fund these outstanding checks when they were presented for payment.

Allowance for Uncollectible Accounts Receivable

For OG&E, customer balances are generally written off if not collected within six months after the original due date. The allowance for uncollectible accounts receivable for OG&E is calculated by multiplying the last six months of electric revenue by the provision rate. The provision rate is based on a 12-month historical average of actual balances written off. To the extent the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. The allowance for uncollectible accounts receivable for Enogex is calculated based on outstanding accounts receivable balances over 180 days old. In addition, other outstanding accounts receivable balances less than 180 days old are reserved on a case-by-case basis when the Company believes the required payment of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable was approximately $4.5 million and $4.2 million at December 31, 2004 and 2003, respectively.

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

For Enogex, credit risk is the risk of financial loss to Enogex if counterparties fail to perform their contractual obligations. Enogex maintains credit policies with regard to its counterparties that management believes minimize overall credit risk. These policies include the evaluation of a potential counterparty's financial condition (including credit rating), collateral requirements under certain circumstances and the use of standardized agreements which provide for the netting of cash flows associated with a single counterparty. Enogex also monitors the financial condition of existing counterparties on an ongoing basis.

Fuel Inventories

OG&E

Fuel inventories for the generation of electricity consist of coal, natural gas and oil. These inventories are accounted for under the last-in, first-out ("LIFO") cost method. The estimated replacement cost of fuel inventories was higher than the stated LIFO cost by approximately $13.7 million and $24.9 million for 2004 and 2003, respectively, based on the average cost of fuel purchased. The amount of fuel inventory was approximately $42.2 million and $60.0 million at December 31, 2004 and 2003, respectively.

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

Enogex

Effective January 1, 2003, natural gas storage inventory used in OGE Energy Resources, Inc.'s ("OERI") business activities are accounted for at the lower of cost or market in accordance with the guidance in Emerging Issues Task Force ("EITF") Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities," which resulted in the rescission of EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," as amended. Prior to January 1, 2003, OERI's inventory was accounted for on a fair value accounting basis utilizing a gas index that in management's opinion approximated the

current market value of natural gas in that region as of the Balance Sheet date. On April 1, 2003, natural gas storage inventory used in OERI's business activities began to be accounted for under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. In order to minimize risk, OERI enters into contracts or hedging instruments to hedge the fair value of this inventory. For any contracts that qualify for hedge accounting under SFAS No. 133, the hedged portion of the inventory is recorded at fair value with an offsetting gain or loss recorded currently in earnings. Ineffectiveness associated with OERI's fair value hedge strategy was not material in 2003 or 2004. The fair value of the hedging instrument is also recorded on the books of OERI as a Price Risk Management asset or liability with an offsetting gain or loss recorded in current earnings. During 2003, OERI utilized hedge accounting under SFAS No. 133 for natural gas storage inventory; however, during 2004, OERI decided not to utilize hedge accounting under SFAS No. 133 for natural gas storage inventory. As part of its recurring business activity, OERI injects and withdraws natural gas under the terms of storage capacity contracts; the amount of natural gas inventory was approximately $29.0 million and $82.4 million at December 31, 2004 and 2003, respectively. See Note 2 for a further discussion.

Effective December 31, 2003, approximately $20.8 million of natural gas storage inventory that was previously classified as Property, Plant and Equipment used in Enogex Inc.'s business activities was reclassified to Fuel Inventories on the Consolidated Balance Sheet. During the fourth quarter of 2003, Enogex implemented a business process to actively manage seasonal opportunities around the four billion cubic feet previously reserved to manage pipeline system requirements during peak periods. The intent of management is to capture commercial opportunities while maintaining adequate inventory levels necessary to meet ongoing contractual obligations.

Gas Imbalances

Gas imbalances occur when the actual amounts of natural gas delivered from or received by the Company's pipeline system differ from the amounts scheduled to be delivered or received. Imbalances are due to or due from shippers and operators and can be settled in cash or made up in-kind. The Company values all imbalances at average market prices estimated to be in effect at the time the imbalance will be settled. Also, included in Gas Imbalances on the Consolidated Balance Sheets are planned or managed imbalances related to Enogex's marketing business, referred to as park and loan transactions. Park and loan assets were approximately $76.0 million and $45.4 million, respectively, at December 31, 2004 and 2003 and park and loan liabilities were approximately $2.4 million and $9.7 million, respectively, at December 31, 2004 and 2003. Operational imbalance assets were approximately $24.1 million and $24.6 million, respectively, at December 31, 2004 and 2003 and operational imbalance liabilities were approximately $20.4 million and $12.8 million, respectively, at December 31, 2004 and 2003.

Property, Plant and Equipment

OG&E

All property, plant and equipment are recorded at cost. Newly constructed plant is added to plant balances at costs which include contracted services, direct labor, materials, overhead,

transportation costs and the allowance for funds used during construction ("AFUDC"). Replacements of major units of property are capitalized as plant. The replaced plant is removed from plant balances and the cost of such property less salvage is charged to Accumulated Depreciation. Repair and replacement of minor items of property are included in the Consolidated Statements of Income as Other Operation and Maintenance Expense. Effective January 1, 2003, removal expense has no longer been charged to Accumulated Depreciation but rather has been charged to regulatory liabilities in accordance with SFAS No. 143.

Enogex

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 and overheads used during construction. Replacements of units of property are capitalized as plant. For group assets, the replaced plant is removed from plant balances and 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 Consolidated Statements of Income as Other Expense. Repair and removal costs are included in the Consolidated Statements of Income as Other Operation and Maintenance Expense.

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

December 31 *(In millions)*	**2004**	2003
OGE Energy Corp. (holding company)		
Property, plant and equipment	**$ 65.3**	$ 57.0
OGE Energy Corp. property, plant and equipment	**65.3**	57.0
OG&E		
Distribution assets	**1,934.0**	1,834.7
Electric generation assets	**1,828.3**	1,628.1
Transmission assets	**552.8**	536.9
Intangible plant	**6.3**	5.3
Other property and equipment	**313.0**	265.1
OG&E property, plant and equipment	**4,634.4**	4,270.1
Enogex		
Transportation and storage assets	**883.6**	879.9
Gathering and processing assets	**483.1**	467.4
Marketing assets	**7.5**	7.3
Enogex property, plant and equipment	**1,374.2**	1,354.6
Total property, plant and equipment	**$6,073.9**	$5,681.7

Depreciation

OG&E

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

production plant and at the account or sub-account level for all other plant, and is based on the average life group method.

Enogex

Depreciation is computed principally on the straight-line method using estimated useful lives of three to 83 years for transportation and storage assets, three to 30 years for gathering and processing assets and three to 10 years for marketing assets. Amortization of intangibles other than debt costs is computed using the straight-line method over the respective lives of the intangibles ranging up to 20 years.

Impairment of Assets

The Company assesses potential impairments of assets or asset groups when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset or asset group. For purposes of recognition and measurement of an impairment loss, a long-lived asset or assets shall be grouped with other assets and liabilities at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities. Estimates of future cash flows used to test the recoverability of a long-lived asset or asset group shall include only the future cash flows (cash inflows less associated cash outflows) that are directly associated with and that are expected to arise as a direct result of the use and eventual disposition of the asset or asset group. The fair value of these assets is based on third-party evaluations, prices for similar assets, historical data and projected cash flow. An impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset. Enogex expects to continue to evaluate the strategic fit and financial performance of each of its assets in an effort to ensure a proper economic allocation of resources. The magnitude and timing of any potential impairment or gain on the disposition of any assets have not been determined or included in the 2005 earnings guidance.

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

Revenue Recognition

OG&E

OG&E reads its customers' meters and sends bills to its customers throughout each month. As a result, there is a significant amount of customers' electricity consumption that has not been billed at the end of each month. An amount is accrued as a receivable for this unbilled revenue based on estimates of usage and prices during the period. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

Enogex

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

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

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

The default processing fee, which decreases the volatility of Enogex's earnings stream by reducing Enogex's exposure to keep-whole processing arrangements, is implemented in the event the natural gas liquids revenue less the associated fuel and shrinkage costs is negative. The Company records any default processing fees billed to customers as deferred revenue until it becomes probable that the processing gross margin threshold in Enogex's Statement of Operating Conditions ("SOC") will not be exceeded. Based on the 2004 processing gross margin, the default processing fees billed to customers in 2004 were recorded as deferred revenue as the 2004 processing gross margin exceeded the 2004 processing gross margin threshold in the SOC.

Automatic Fuel Adjustment Clauses

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component in the cost-of-service for ratemaking, are passed through to OG&E's customers through automatic fuel adjustment clauses, which are subject to periodic review by the OCC, the APSC and the FERC. See Note 18 of Notes to Consolidated Financial Statements for a discussion of the proceeding before the OCC in which OG&E is seeking to recover costs billed to it by Enogex for gas transportation and storage services.

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 10 for a further discussion related to the Company's Stock Incentive Plan. Also, see Note 2 for a discussion of a recent accounting pronouncement which replaces SFAS No. 123 that the Company will adopt effective July 1, 2005.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure – an amendment of FASB Statement No. 123." SFAS No. 148 amended the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. The following table reflects pro forma net income and income per average common share had the Company elected to adopt the fair value based method of SFAS No. 123:

Year Ended December 31 *(In millions, except per share data)*	**2004**	2003	2002
Net income, as reported	**$ 153.5**	$ 129.8	$ 90.8
Add:			
Stock-based employee compensation expense included in reported net income, net of related tax effects	---	---	---
Deduct:			
Stock-based employee compensation expense determined under fair value based method for all awards, net of			

related tax effects	**1.0**	1.2	1.1
Pro forma net income	**$ 152.5**	$ 128.6	$ 89.7
Income per average common share			
Basic - as reported	**$ 1.74**	$ 1.59	$ 1.16
Basic - pro forma	**$ 1.73**	$ 1.57	$ 1.15
Diluted - as reported	**$ 1.73**	$ 1.58	$ 1.16
Diluted - pro forma	**$ 1.72**	$ 1.57	$ 1.15

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

The components of accumulated other comprehensive loss at December 31, 2004 and 2003 are as follows:

December 31 *(In millions)*	**2004**	2003
Minimum pension liability adjustment, net of tax	**$ (72.7)**	$ (59.7)
Deferred hedging gains, net of tax	**0.2**	0.9
Unrealized gains on available-for-sale securities, net of tax	---	0.4
Settlement of cash flow hedge, net of tax	**(2.5)**	---
Total accumulated other comprehensive loss, net of tax	**$ (75.0)**	$ (58.4)

Minimum Pension Liability Adjustment

Accumulated other comprehensive loss at both December 31, 2004 and 2003 included an after tax loss ($118.6 million pre-tax and $97.4 million pre-tax, respectively) related to a minimum pension liability adjustment based on a review of the funded status of the Company’s pension plan by the Company’s actuarial consultants as of December 31, 2004.

Cash Flow Hedges

The Company entered into four separate interest rate swap agreements, effective April 16, 2004, April 21, 2004, May 17, 2004 and July 16, 2004, respectively, to hedge approximately $20.0 million, $30.0 million, $20.0 million and $10.0 million, respectively, of future interest payments of long-term debt that was issued in November 2004. These interest rate swap agreements originally matured on October 15, 2004 but the maturity date was extended to November 8, 2004. The Company terminated these cash flow hedges on November 9, 2004, at which time approximately $4.0 million was recorded in other comprehensive income. This amount will be amortized to interest expense over the life of the related long-term debt.

Environmental Costs

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

Reclassifications

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

2. Accounting Pronouncements

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

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arising under the doctrine of promissory estoppel. The recognition of an asset retirement obligation is capitalized as part of the carrying amount of the long-lived asset. Asset retirement obligations represent future liabilities and, as a result, accretion expense is accrued on this liability until such time as the obligation is satisfied. In connection with the adoption of SFAS No. 143, the Company assessed whether it had a legal obligation within the scope of SFAS No. 143. The Company determined that it had a legal obligation to remove certain assets associated with their retirements. As the Company currently has no plans to retire any of these assets (except as discussed below) and the remaining life is indeterminable, an asset retirement obligation was not recognized; however, the Company will monitor these assets and record a liability when a reasonable estimate of the fair value can be made. During the third quarter of 2004, OG&E determined the definite life of a legal obligation within the scope of SFAS No. 143 to retire certain assets related to the expiration of a power supply contract in June 2006. OG&E recorded an asset retirement obligation of approximately $1.1 million at September 30, 2004 and began amortizing this amount over 21 months beginning October 1, 2004.

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

In October 2002, the EITF reached a consensus on certain issues covered in EITF 02-3. One consensus of EITF 02-3 was to rescind EITF 98-10 effective for fiscal periods beginning after December 15, 2002. Effective October 25, 2002, all new contracts and physical inventories that would have been accounted for under EITF 98-10 were no longer marked to market through earnings unless the contracts met the definition of a derivative under SFAS No. 133. Application of the consensus for energy contracts and inventory that existed on or before October 25, 2002 that remain in effect at the date this consensus was initially applied were recognized as a cumulative effect of a change in accounting principle in accordance with APB Opinion No. 20, "Accounting Changes." As a result, only energy contracts that meet the definition of a derivative in SFAS No. 133 are carried at fair value. The Company adopted this consensus effective January 1, 2003 resulting in a pre-tax loss of approximately $9.6 million ($5.9 million after tax). The loss, which was accounted for as a cumulative effect of a change in accounting principle during the first quarter of 2003, was primarily related to natural gas held in storage for trading

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purposes. This natural gas held in storage was sold during the first quarter of 2003 resulting in an increase in the gross margin on revenues ("gross margin") in excess of the cumulative effect loss described above.

In January 2003, the FASB issued Interpretation No. 46, "Consolidation of Variable Interest Entities, an interpretation of Accounting Research Bulletin No. 51." In October 2003, the FASB issued Interpretation No. 46-6, "Effective Date of FASB Interpretation No. 46, Consolidation of Variable Interest Entities," in which the FASB agreed to defer, for public companies, the required effective dates to implement Interpretation No. 46 for interests held in a variable interest entity ("VIE") or potential VIE that was created before February 1, 2003. The Company adopted this new interpretation effective December 31, 2003 resulting in a pre-tax gain of approximately $0.8 million ($0.5 million after tax). The adoption of this interpretation resulted in the deconsolidation of the trust originated preferred securities of OGE Energy Capital Trust I, a wholly-owned financing trust of the Company (see Note 12), and the consolidation of Energy Insurance Bermuda Ltd. Mutual Business Program No. 19 ("MBP 19"). Effective January 1, 2004, the reinsurer of the MBP 19 program agreed to remove the guarantee requirement which enabled the Company to terminate the standby letter of credit previously provided. However, the reinsurer added a ratings trigger requirement in the revised agreement such that if the commercial paper rating of the Company is lowered by two grades, MBP 19 may be surcharged an additional premium, which may result in an additional premium to the Company. Because the guarantee requirement was removed, the total equity investment at risk of MBP 19 was deemed sufficient to permit it to finance its activities without additional subordinated financial support from other parties. Therefore, effective January 1, 2004, MBP 19 was not considered a VIE as defined in Interpretation No. 46 which resulted in the deconsolidation of MBP 19 during the first quarter of 2004. The Company plans to terminate the MBP 19 program during the first quarter of 2005 and does not expect the impact of terminating this program to have a material effect on the Company's consolidated financial position or results of operations.

In November 2004, the FASB issued SFAS No. 151, "Inventory Costs, an Amendment to ARB No. 43, Chapter 4." This statement amends the guidance in Accounting Research Bulletin No. 43, Chapter 4 "Inventory Pricing", to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs and spoilage. This statement requires these items to be recognized as current period charges regardless of whether the "so abnormal" criterion is met. Adoption of SFAS No. 151 is required for inventory costs incurred during fiscal years beginning after June 15, 2005. The Company will adopt this new standard effective January 1, 2006. Management has not yet determined what the impact of this new standard will be on its consolidated financial position or results of operations.

In December 2004, the FASB issued SFAS No. 123 (Revised), "Share-Based Payment", 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

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shares or other equity instruments. This statement applies to all awards granted after the required effective date and to awards modified, repurchased or cancelled after that date. The cumulative effect of initially applying this statement, if any, is recognized as of the required effective date. This statement requires a public entity to measure and recognize the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award (with limited exceptions). The grant-date fair value of employee share options and similar instruments will be estimated using option-pricing models adjusted for the unique characteristics of those instruments. If an equity award is modified after the grant date, incremental compensation cost will be recognized in an amount equal to the excess of the fair value of the modified award over the fair value of the original award immediately before the modification. As of the required effective date, all public entities that used the fair-value based method for either recognition or disclosure under SFAS No. 123 will apply this statement using a modified version of prospective application. Under that transition method, compensation cost is recognized on or after the required effective date for the portion of outstanding awards for which the requisite service has not yet been rendered, based on the grant-date fair value of those awards calculated under SFAS

No. 123 for either recognition or pro forma disclosures. For periods prior to the required effective date, those entities may elect to apply a modified version of retrospective application under which financial statements for prior periods are adjusted on a basis consistent with the pro forma disclosures required for those periods by SFAS No. 123. Adoption of SFAS No. 123(R) is required for public entities as of the beginning of the first interim or annual period beginning after June 15, 2005. The Company will adopt this new standard effective July 1, 2005. Management has not yet determined what the impact of this new standard will be on its consolidated financial position or results of operations.

3. Price Risk Management Assets and Liabilities

Non-Trading Activities

The Company periodically utilizes derivative contracts to manage the exposure of its assets to unfavorable changes in commodity prices, as well as to reduce exposure to adverse interest rate fluctuations. During 2004 and 2003, the Company's use of non-trading price risk management instruments involved the use of commodity price and interest rate swap agreements. These agreements involve the exchange of fixed price or rate payments in exchange for floating price or rate payments over the life of the instrument without an exchange of the underlying principal amount.

In accordance with SFAS No. 133, the Company recognizes all of its derivative instruments as Price Risk Management assets or liabilities in the Consolidated Balance Sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and resulting designation. For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative instrument is recognized in current earnings on the same line item as the gain or loss recorded for the change in the fair value of the hedged item. For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of Accumulated Other Comprehensive Income and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portion of a

derivative's change in fair value is recognized currently in earnings. As a matter of policy, all hedged items and the derivatives used for cash flow hedges must be identical with respect to time and location and must be in compliance with SFAS No. 133. Forecasted transactions designated as the hedged item in a cash flow hedge are regularly evaluated to assess whether they continue to be probable of occurring. If the forecasted transactions are no longer probable of occurring, hedge accounting will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings. Any amounts recorded in Accumulated Other Comprehensive Income will remain in other comprehensive income until such time as the forecasted transaction is deemed probable not to occur.

The Company's interest rate swap agreements include both fair value and cash flow hedges. The fair value hedges qualify for the shortcut method prescribed by SFAS No. 133. Under the shortcut method, the Company assumes that the hedged item's change in fair value is exactly as much as the derivative's change in fair value. 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 Notes 1 and 13 for a description of the Company's interest rate swap agreements.

Trading Activities

The Company, through its subsidiary, OERI, engages in energy trading activities primarily related to the purchase and sale of natural gas. Contracts utilized in these activities generally include forward swap contracts as well as over-the-counter and exchange traded futures and options. Energy trading activities are accounted for in accordance with SFAS No. 133 and EITF 02-3. In accordance with SFAS No. 133, financial instruments that qualify as derivatives are reflected at fair value with the resulting unrealized gains and losses recorded as Price Risk Management assets or liabilities in the Consolidated Balance Sheets, classified as current or long-term based on their anticipated settlement. Unrealized gains and losses from changes in the market value of open contracts are included in Natural Gas Pipeline Operating Revenues in the Consolidated Statements of Income. Energy trading contracts resulting in delivery of a commodity that meet the requirements of EITF Issue No. 99-19, "Reporting Revenues Gross as a Principal or Net as an Agent," are included as sales or purchases in the Consolidated Statements of Income depending on whether the contract relates to the sale or purchase of the commodity.

4. Enogex – Discontinued Operations

Enogex sold its interests in Belvan Corp., Belvan Limited Partnership and Todd Ranch Limited Partnership ("Belvan") for approximately $9.8 million in March 2002. The Company recognized an after tax gain of approximately $1.6 million related to the sale of these assets.

Enogex sold its exploration and production assets located in Oklahoma, Texas, Arkansas and Mississippi for approximately $15.0 million in August 2002. The Company recognized an after tax gain of approximately $2.3 million related to the sale of these assets.

Enogex sold its exploration and production assets located in Michigan for approximately $32.0 million in November 2002. The Company recognized an after tax gain of approximately $2.9 million related to the sale of these assets.

Enogex sold its interests in the NuStar Joint Venture ("NuStar") for approximately $37.0 million in February 2003. The Company recognized an after tax gain of approximately $1.4 million related to the sale of these assets in the first quarter of 2003. Following completion of the final accounting for the NuStar sale, the Company recorded an additional charge of approximately $0.2 million after tax in the third quarter of 2003. The final accounting is subject to approval by all parties to the sale of the joint venture interest. During 2004, the Company recognized approximately $0.5 million after tax from funds received related to an overpayment for natural gas purchases in a prior period.

The Consolidated Financial Statements of the Company have been restated to reflect Enogex's exploration and production assets, NuStar and Belvan, all of which were part of the Natural Gas Pipeline segment, as discontinued operations. Accordingly, revenues, costs and expenses and cash flows of the exploration and production assets, NuStar and Belvan have been excluded from the respective captions in the Consolidated Financial Statements and have been reported as "Income (loss) from Discontinued Operations" and "Net Cash Provided from Discontinued Operations." There were no outstanding balances related to the exploration and production assets, NuStar and Belvan on the Consolidated Balance Sheets. Summarized financial information for the discontinued operations as of December 31 is as follows:

CONSOLIDATED STATEMENTS OF INCOME DATA

(In millions)	**2004**	2003	2002
Operating revenues from discontinued operations	**$ 0.8**	$ 7.8	$ 79.5
Income from discontinued operations before taxes	**0.8**	1.8	8.4

5. Asset Disposals

Ozark sold approximately 29 miles of transmission lines of its pipeline for approximately $10.0 million in January 2003. Ozark recognized a gain of approximately $5.3 million and approximately $1.1 million in minority interest expense in the first quarter of 2003 related to the sale of these assets, which is recorded in Other Income and Other Expense, respectively, in the Consolidated Statements of Income. These assets were part of the Natural Gas Pipeline segment.

During the second quarter of 2004, OG&E sold land and buildings near its principal executive offices for approximately $0.9 million. OG&E recognized a gain of approximately $0.3 million related to the sale of this asset, which is recorded in Other Income in the Consolidated Statements of Income. This asset was part of the Electric Utility segment.

In September 2004, OG&E sold its interests in its natural gas producing properties for approximately $3.1 million. These interests had a carrying value of approximately $0.1 million and OG&E recognized a gain of approximately $3.0 million, which is recorded in Other Income in the Consolidated Statements of Income. In December 2004, OG&E recognized an additional

gain of approximately $0.2 million related to the sale of these interests. These interests were part of the Electric Utility segment.

See Note 6 for additional asset sales by the Company.

6. Impairment of Assets

Processing and Compression Assets

In April 2002, in response to unsatisfactory operating results, including the negative impact of lower natural gas and natural gas liquids prices, a comprehensive review of the Enogex strategy and operations was undertaken. From an operational perspective, this review of the utilization of gathering and processing assets demonstrated that Enogex had too much compression horsepower installed and that there was excess capacity at the natural gas processing plants. As a result of the review, a plan was developed to remove excess compressors from the pipeline system. By removing excess compressor capacity from the system, fuel and operation and maintenance costs were reduced. The review of the operations of the natural gas processing plants also identified opportunities to consolidate natural gas volumes at certain processing plants and to bypass others. As a result of consolidating these volumes, the utilization of the natural gas processing plants was maximized and the bypassed plants were taken out of service. As the equipment was removed, the strategy dictated that idle assets be disposed of so that the proceeds could be used for capital expenditures in other areas or to pay down the Company’s debt.

As a result of decisions made to remove these assets from service and to dispose of them, an evaluation of the fair value of the assets was made. Since the fair value of these assets was less than the carrying value of the assets, the Company recorded a pre-tax impairment loss of approximately $48.3 million in the Natural Gas Pipeline segment during the fourth quarter of 2002.

The planning for the marketing of these assets commenced late in 2002, when a position was created at Enogex to manage assets and, if necessary, liquidate any surplus assets. The natural gas processing plants were actively marketed during 2003; however, the Company had limited success in disposing of these plants in 2003. Other operators in the mid-continent region either were not expanding operations or also were marketing natural gas processing plants. Therefore, there was very little activity in the region for natural gas processing plants. Efforts were made to market the natural gas processing plants in the international market; however, these efforts also were not successful.

Efforts to sell the excess compressor assets during 2003 faced similar market conditions and similar difficulties. As a result, Enogex’s business development group, as part of their efforts to dispose of the compressor assets, began negotiating in 2003 with an independent party to form a joint venture that would rent out the compressors. Certain of these impaired assets were contributed to the joint venture discussed below.

Also during 2003, another evaluation of the horsepower of compression needed to meet the operational requirements of the Company’s gathering and transmission system was performed based on the changed market conditions. The review identified additional compressor equipment that could be removed from the system and an additional pre-tax impairment loss of approximately $9.2 million was recorded in the Natural Gas Pipeline segment in the fourth quarter of 2003 to recognize the difference between the carrying value of these units and their fair value expected to be realized in a disposal. Certain of these impaired assets were contributed to the joint venture discussed below. The impairments recorded in the fourth quarters of 2002 and 2003 resulted from plans to dispose of these assets at prices below the carrying amount. The fair value of these assets was determined based on third-party evaluations, prices for similar assets, historical data and projected cash flows.

During the year ended December 31, 2004, the Company sold certain of its compression and processing assets for approximately $5.0 million and recognized an after tax gain of approximately $1.8 million related to the sale of these assets. The carrying amount of the remaining assets (that were the subject of the impairment charges in the fourth quarters of 2002 and 2003) was approximately $2.6 million and $11.9 million at December 31, 2004 and 2003, respectively. As discussed below, for any remaining assets that were the subject of the impairment charges in the fourth quarters of 2002 and 2003, the Company has either contributed the assets to the joint venture or reclassified these assets from held for sale to held and used as of December 31, 2004.

During the third quarter of 2004, Enogex entered into a joint venture arrangement with a third party and contributed certain of its natural gas compression assets (with a carrying amount of approximately $3.9 million) to the joint venture. The objective of the joint venture is to derive value from the assets by renting the natural gas compressors. Enogex Compression was created to act as the participating entity in the joint venture. Enogex Compression holds a majority ownership in the joint venture, although the actual ownership percentages may fluctuate based on the relative capital contributions of Enogex Compression and the third party member. The third party acts as the manager and conducts the daily operations of the joint venture. These assets are part of the Natural Gas Pipeline segment.

During the third quarter of 2004, the Company reclassified an asset in the Natural Gas Pipeline segment from assets held for sale to assets held and used. This asset had a carrying amount of approximately $0.8 million at the time the asset was reclassified. This decision to reclassify the asset was based on the fact that when this asset was previously impaired, there was a declining natural gas processing market, declining volumes and a decline in the British thermal unit content of the gas flowing through the processing plants. Since the time of impairment, natural gas prices have increased and, with higher sustained natural gas prices, drilling activity has also significantly increased. Also, new producing wells are also producing richer natural gas that must be processed. As a result, in accordance with SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," if a long-lived asset is reclassified from assets held for sale to assets held for use, the long-lived asset should be measured at the lower of its carrying amount before the asset was classified as held for sale less any depreciation expense that would have been recognized had the asset been continuously classified as held and used or its fair value at the date of the subsequent decision not to sell. The Company determined the fair

value of this asset, which was less than the carrying amount described above, based on historical data and projected cash flows and recorded a gain of approximately $0.3 million during 2004 related to reclassifying this asset from assets held for sale to assets held and used, which was recorded as a credit to Impairment of Assets in the Consolidated Statement of Income.

In October 2004, the Company reclassified a large electric driven compressor in the Natural Gas Pipeline segment that was previously classified as assets held for sale to assets held and used. This compressor had a carrying amount of approximately $1.2 million at September 30, 2004. This decision was based on the fact that, when this asset was previously impaired, there was excess horsepower available for compression on the pipeline system and this asset was identified as surplus that would be sold. Since the time of impairment, it has become economical to reactivate this compressor due to higher fuel costs related to natural gas-fired compression and changes to the compression requirements for the pipeline. As a result, in accordance with SFAS No. 144, if a long-lived asset is reclassified from assets held for sale to assets held for use, the long-lived asset should be measured at the lower of its carrying amount before the asset was classified as held for sale less any depreciation expense that would have been recognized had the asset been continuously classified as held and used or its fair value at the date of the subsequent decision not to sell. The Company determined the fair value of this asset, which was less than the carrying amount described above, based on a third party valuation of the asset and, as based on this valuation, the Company recorded an additional impairment charge of approximately $0.3 million during the fourth quarter of 2004 related to reclassifying this asset from assets held for sale to assets held and used, which was recorded in Impairment of Assets in the Consolidated Statement of Income.

In December 2004, the Company reclassified several compressors and processing plants in the Natural Gas Pipeline segment that were previously classified as assets held for sale to assets held and used. These assets had a carrying amount of approximately $1.6 million at December 31, 2004. This decision was based on the fact that these assets are no longer being marketed and the Company believes the value of the future benefit of holding these assets exceeds the current fair market value. As a result, in accordance with SFAS No. 144, if a long-lived asset is reclassified from assets held for sale to assets held for use, the long-lived asset should be measured at the lower of its carrying amount before the asset was classified as held for sale less any depreciation expense that would have been recognized had the asset been continuously classified as held and used or its fair value at the date of the subsequent decision not to sell. The Company determined the fair value of these assets, which was less than the carrying amount described above, based on a third party valuation of the assets and, as a result, the Company recorded a net gain of approximately $0.8 million during the fourth quarter of 2004 related to reclassifying these assets from assets held for sale to assets held and used, which was recorded as a credit to Impairment of Assets in the Consolidated Statement of Income.

Pipeline Assets

During the third quarter of 2004, the Company recognized a pre-tax impairment loss of approximately $8.6 million in the Natural Gas Pipeline segment related to Enogex natural gas pipeline assets. During September 2004, Enogex received notification from a customer that a transportation agreement involving four of Enogex's non-contiguous pipeline asset segments

located in West Texas and used to serve the customer's power plants would be terminated effective December 31, 2004. In connection with the preparation of the third quarter 2004 financial statements, Enogex performed an evaluation on these assets and concluded that an impairment charge needed to be recorded. The primary reason for this determination was that these four pipeline asset segments were originally built for the specific purpose of providing gas transmission service to this customers' four power plants that have been or are in the process of being shut down, and, as a result, other alternative commercial uses for these facilities are considered unlikely. The fair value of these assets was determined based on historical data and projected cash flows. Following the impairment charge, the carrying amount of these assets was approximately $0.9 million at September 30, 2004. The depreciation lives for these assets as of September 30, 2004 were revised based on these circumstances. During the fourth quarter of 2004, additional depreciation of approximately $0.7 million and an additional impairment charge of approximately $0.2 million were recorded related to these assets. In December 2004, the Company received notification that all of this customers' plants in West Texas had shut down and service is no longer required. The Company is currently evaluating other commercial opportunities for these assets as well as contacting other parties that may be interested in acquiring any of these assets.

7. Supplemental Cash Flow Information

The following table discloses information about investing and financing activities that affect recognized assets and liabilities but which do not result in cash receipts or payments. Also disclosed in the table is cash paid for interest, net of interest capitalized, and cash paid for income taxes, net of income tax refunds.

Year Ended December 31 *(In millions)*	**2004**	2003	2002
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Power plant long-term service agreement	$ **6.0**	$ ---	$ ---
Issuance of common stock	**2.2**	11.4	5.6
Change in fair value of long-term debt due to interest rate swaps	**0.3**	(8.3)	18.3

Change in property, plant and equipment due to transfer of inventory	---	7.1	---
Assumption of asset and related debt	---	---	42.5
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash Paid During the Period for			
Interest (net of interest capitalized of $1.7, $0.5, $0.9)	**$ 85.2**	$ 92.6	$ 109.7
Income taxes (net of income tax refunds)	**37.4**	(33.2)	28.2

8. Income Taxes

The items comprising income tax expense are as follows:

Year ended December 31 *(In millions)*	**2004**	2003	2002
Provision (Benefit) for Current Income Taxes from Continuing Operations			
Federal	**$ 22.2**	$ (35.8)	$ 12.5
State	**2.5**	(6.1)	(0.6)
Total Provision (Benefit) for Current Income Taxes from Continuing Operations	**24.7**	(41.9)	11.9
Provision for Deferred Income Taxes, net from Continuing Operations			
Federal	**53.5**	105.3	31.7
State	**4.8**	16.1	6.6
Total Provision for Deferred Income Taxes, net from Continuing Operations	**58.3**	121.4	38.3
Deferred Investment Tax Credits, net	**(5.2)**	(5.2)	(5.2)
Income Taxes Relating to Other Income and Deductions	**2.4**	(0.6)	(0.4)
Total Income Tax Expense from Continuing Operations	**$ 80.2**	$ 73.7	$ 44.6

In connection with the filing in the third quarter of 2003 of the Company’s consolidated income tax returns for 2002, the Company 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 the Company’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. As a result of this tax net operating loss, tax credits associated with Enogex’s natural gas production were not realized during 2003 and resulted in approximately $1.8 million in higher income tax expense in discontinued operations. The Company received federal and state income tax refunds of approximately $50.8 million during 2003 related to this tax accounting method change.

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

Year ended December 31	**2004**	2003	2002
Statutory federal tax rate	**35.0%**	35.0%	35.0%
State income taxes, net of federal income tax benefit	**2.0**	3.1	3.1
Tax credits, net	**(2.2)**	(2.5)	(4.1)
Other, net	**(0.4)**	(0.4)	1.5
Effective income tax rate as reported	**34.4%**	35.2%	35.5%

The Company files consolidated income tax returns. Income taxes are allocated to each affiliate 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 OG&E. The components of Accumulated Deferred Taxes at December 31, 2004 and 2003, respectively, are as follows:

(In millions)	2004	2003
Current Accumulated Deferred Tax Assets		
Accrued vacation	**$ 6.0**	$ 5.8
Uncollectible accounts	**1.8**	1.4
Other	**5.9**	2.2
Total Current Accumulated Deferred Tax Assets	**$ 13.7**	$ 9.4
Non-Current Accumulated Deferred Tax Liabilities		
Accelerated depreciation and other property related differences	**$ 768.3**	$ 710.4
Allowance for funds used during construction	**31.1**	33.1
Income taxes refundable to customers, net	**11.9**	12.2
Bond redemption-unamortized costs	**7.3**	7.7
Company pension plan	**2.6**	8.9
Other	**1.3**	(6.1)
Total Non-Current Accumulated Deferred Tax Liabilities	**822.5**	766.2
Non-Current Accumulated Deferred Tax Assets		
Deferred federal investment tax credits	**(10.3)**	(12.1)
Postretirement medical and life insurance benefits	**(10.2)**	(6.8)
Total Non-Current Accumulated Deferred Tax Assets	**(20.5)**	(18.9)
Non-Current Accumulated Deferred Income Tax Liabilities, net	**$ 802.0**	$ 747.3

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

American Jobs Creation Act of 2004

On October 22, 2004, President Bush signed into law the American Jobs Creation Act of 2004 (the “Jobs Creation Act”). The Jobs Creation Act amended and added a significant number of provisions to the Internal Revenue Code and these changes affect virtually all taxpayers. The Jobs Creation Act includes a provision that entitles all U.S. manufacturers with qualified

manufacturing activities to a “Deduction Related to Production Activities” (“DRPA”). Certain activities of the Company, including the generation of electricity and the processing of natural gas, 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 OG&E is an integrated electric utility and Enogex is an integrated natural gas transportation company, both will be required to allocate income and expenses to their “qualified production activity.” The U.S. Treasury Department issued guidance related to the DRPA on January 19, 2005 and this guidance provides rules for determining taxable income when a portion of a taxpayer’s income is derived from a qualified production activity. The FASB has determined that the DRPA will be classified as a “special deduction” for purposes of computing income tax expense which will have the effect of reducing the Company’s overall effective tax rate to the extent the Company can claim a deduction. The Company is in the process of analyzing these rules to determine the effect of the DRPA on its overall effective tax rate and income tax expense.

9. Common Stock

In April 2003, the Company filed a Form S-3 Registration Statement registering the sale of up to $130.0 million of unsecured debt securities or shares of the Company’s common stock. On August 27, 2003 and September 5, 2003, respectively, the Company issued 4,650,000 shares and 674,074 shares of its common stock under this registration statement at a public offering price of $21.60 per share.

In April 2003, the Company filed a Form S-3 Registration Statement to register 7,000,000 shares of the Company’s common stock pursuant to the Company’s Automatic Dividend Reinvestment and Stock Purchase Plan (“DRIP/DSPP”). Under the terms of the DRIP/DSPP, the Company may accept requests for optional investments in amounts greater than $0.1 million per year and may offer a discount of up to three percent from current market prices. This program allows the Company to sell additional common stock at a smaller discount than that normally incurred in a secondary equity offering. During the year ended December 31, 2004, the Company issued 721,021 shares of common stock and 1,238,043 shares of common stock at a discount of 1.50 percent and 1.25 percent, respectively, pursuant to the DRIP/DSPP. During the year ended December 31, 2003, the Company issued 615,721 shares of common stock and 1,855,989 shares of common stock at a discount of 1.75 percent and 1.50 percent, respectively, pursuant to the DRIP/DSPP. Also, as part of the DRIP/DSPP, the Company issued 242,003 shares of common stock, 938,497 shares of common stock and 499,397 shares of

common stock at no discount during the years ended December 31, 2004, 2003 and 2002, respectively.

For the years ended December 31, 2004 and 2003, respectively, there were 392,686 shares of new common stock and 134,098 shares of new common stock issued pursuant to the Company's Stock Incentive Plan, related to exercised stock options.

At December 31, 2004, there were 10,058,491 shares of unissued common stock reserved for the various employee and Company stock plans. Beginning July 30, 2002, the Company issued new common stock to satisfy the common stock requirements of the DRIP/DSPP rather than purchasing the common stock on the open market. Effective December 1, 2003, the Company began purchasing common stock on the open market to satisfy the common stock requirements of the DRIP/DSPP. Beginning August 1, 2004, the Company issued new common stock to satisfy the common stock requirements of the DRIP/DSPP rather than purchasing the common stock on the open market. Effective January 1, 2005, the Company began purchasing common stock on the open market to satisfy the common stock requirements of the DRIP/DSPP.

Shareowners Rights Plan

In December 1990, OG&E adopted a Shareowners Rights Plan designed to protect shareowners' interests in the event that OG&E was ever confronted with an unfair or inadequate acquisition proposal. In connection with the corporate restructuring, the Company adopted a substantially identical Shareowners Rights Plan in August 1995. Pursuant to the plan, the Company declared a dividend distribution of one "right" for each share of Company common stock. As a result of the June 1998 two-for-one stock split, each share of common stock is now entitled to one-half of a right. Each right entitles the holder to purchase from the Company one one-hundredth of a share of new preferred stock of the Company under certain circumstances. The rights may be exercised if a person or group announces its intention to acquire, or does acquire, 20 percent or more of the Company's common stock. Under certain circumstances, the holders of the rights will be entitled to purchase either shares of common stock of the Company or common stock of the acquirer at a reduced percentage of the market value. In October 2000, the Shareowners Rights Plan was amended and restated to extend the expiration date to December 11, 2010 and to change the exercise price of the rights.

10. Stock Incentive Plan

On January 21, 1998, the Company adopted a Stock Incentive Plan (the "1998 Plan"). Under this Plan, restricted stock, stock options, stock appreciation rights and performance units may be granted to officers, directors and other key employees. The Company had authorized the issuance of up to 4,000,000 shares under the 1998 Plan.

In 2003, the Company 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. The Company has authorized the issuance of up to 2,700,000 shares under the 2003 Plan.

Restricted Stock

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

Performance Units

During 2004 and 2003, respectively, the Company awarded 162,591 performance units and 128,469 performance units to certain employees of the Company. These performance units represent the value of one share of the Company's common stock. These performance units are contingently awarded and will be payable in cash or shares of the Company'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 the Company's total shareholder return relative to the total shareholder return of a peer group of companies. Each performance unit is subject to forfeiture if the recipient ceases to render substantial services to the Company or a subsidiary for any reason other than death, disability or retirement.

Stock Options

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

	2004		2003		2002	
	Number of Options	**Weighted Average Price**	Number of Options	Weighted Average Price	Number of Options	Weighted Average Price
Options Outstanding at beginning of year	**2,871,802**	**$21.6253**	2,419,360	$23.4400	1,570,027	$24.0475
Granted	**380,400**	**23.5750**	838,700	16.6850	959,600	22.2716
Exercised	**(392,686)**	**19.5590**	(134,098)	18.8174	(10,199)	18.2500
Cancelled	**(31,602)**	**23.2500**	(252,160)	24.0963	(100,068)	22.2988
Options Outstanding at end of year	**2,827,914**	**$22.1564**	2,871,802	$21.6253	2,419,360	$23.4400
Options Exercisable at end of year	**1,809,441**	**$23.2946**	1,408,255	$24.2019	1,202,053	$24.8966

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

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

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

		Options Outstanding		Options Exercisable	
Range of Exercise Prices	Weighted-Average Remaining Contractual Life	Number Outstanding	Weighted-Average Exercise Price	Number Outstanding	Weighted-Average Exercise Price
$16.69 - $22.70	7.11 years	1,789,214	$ 19.9781	1,099,241	$ 20.9083
$23.58 - $28.75	5.33 years	1,038,700	$ 25.9086	710,200	$ 26.9880

11. Earnings Per Share

Outstanding shares for purposes of basic and diluted earnings per average common share were calculated as follows:

Year ended December 31 *(In millions)*	**2004**	2003	2002
Average Common Shares Outstanding			
Basic average common shares outstanding	**88.0**	81.8	78.1
Effect of dilutive securities:			
Employee stock options and unvested stock grants	**0.3**	0.1	0.1
Contingently issuable shares (performance units)	**0.2**	0.2	---
Diluted average common shares outstanding	**88.5**	82.1	78.2

For the years ended December 31, 2004, 2003 and 2002, respectively, approximately 0.6 million shares, 1.7 million shares and 1.7 million shares related to outstanding employee stock options were not included in the calculation of diluted earnings per average common share because the effect of including those shares would be anti-dilutive as the exercise price of the stock options exceeded the average common stock market price during the respective period.

12. Trust Originated Preferred Securities

On October 21, 1999, OGE Energy Capital Trust I issued $200.0 million principal amount of 8.375 percent trust preferred securities that mature on October 15, 2039. Distributions paid by the financing trust were financed through payments on debt securities issued by the Company and held by the financing trust. Distributions paid to preferred security holders are recorded as Interest Expense on Trust Preferred Securities in the Consolidated Statements of Income for the year ended December 31, 2002. The Company adopted FASB Interpretation No.

46 on December 31, 2003 which resulted in the trust preferred securities being deconsolidated in the Company's Consolidated Financial Statements for the year ended December 31, 2003. As a result of deconsolidating the trust preferred securities, there was a non-cash increase in Other Property and Investments and Long-Term Debt – Unconsolidated Affiliate of approximately $6.2 million in the Consolidated Balance Sheet at December 31, 2003. Also, distributions paid to preferred security holders are recorded as Interest Expense – Unconsolidated Affiliate in the Consolidated Statements of Income for the year ended December 31, 2003. On October 15, 2004, the Company caused all of the outstanding trust preferred securities to be redeemed at $25 per share (100 percent of liquidation value). The redemption was initially funded with cash on hand and approximately $170.0 million in commercial paper. The Company refinanced a portion of this short-term debt with $100.0 million of long-term debt issued in November 2004. In October 2004, the Company wrote off approximately $5.9 million related to unamortized debt issuance costs for the trust preferred securities which is included in Interest on Short-term Debt and Other Interest Charges in the Consolidated Statement of Income.

13. Long-Term Debt

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

Long-Term Debt with Optional Redemption Provisions

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

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

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

All of these Bonds are subject to redemption at the option of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to the date of purchase. The bond holders, on any business day, can request repayment of the Bond by delivering an irrevocable notice to the tender agent stating the principal amount of the Bond, payment instructions for the purchase price and the business day the Bond is to be purchased. The repayment option may only be exercised by the holder of a Bond for the principal amount. A third party remarketing agent for the Bonds will attempt to remarket any Bonds tendered for

purchase. Since the original issuance of these series of Bonds in 1995 and 1997, the remarketing agent has successfully remarketed all tendered bonds. If the remarketing agent is unable to remarket any such Bonds, the Company is obligated to repurchase such unremarketed Bonds. The Company has sufficient liquidity to meet these obligations.

Early Retirement of Long-Term Debt

In 1998, Enogex issued a note in the amount of approximately $5.7 million payable to an unaffiliated former partial interest owner of NOARK. The note had a maturity date of July 1, 2020 and an interest rate of 7.00 percent. Principal and interest payments of approximately $0.8 million were due annually beginning July 1, 2004. In July 2004, Enogex made the initial $0.8 million payment and also made a payment of approximately $7.8 million, which included accrued interest since inception of the note, to repay the outstanding note balance and satisfy its remaining obligations related to this note. Enogex recorded a pre-tax gain of approximately $0.1 million in the third quarter of 2004 related to this transaction.

Issuance of Long-Term Debt

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

In September 2004, the Company filed a Form S-3 Registration Statement registering the sale of up to $200.0 million of the Company's unsecured debt securities. In November 2004, the Company issued $100.0 million of long-term debt, the proceeds of which were used to replace a portion of the short-term debt incurred to fund the redemption of the trust preferred securities on October 15, 2004. This new debt has a maturity date of November 15, 2014 and an interest rate of 5.00 percent.

Non-recourse Debt of Joint Venture

On June 15, 1998, NOARK issued $80.0 million of long-term notes in a private placement. The Company guaranteed 40 percent of these notes, while the joint venture partner guaranteed 60 percent of the notes. The notes mature on June 1, 2018, and require semi-annual principal payments of $1.0 million plus interest at a fixed rate of 7.15 percent with a final balloon payment of $40 million due at maturity. The Company's portion of the semi-annual principal payments is approximately $0.4 million. The joint partner's portion of this long-term debt is included in Non-recourse Debt of Joint Venture in the Consolidated Balance Sheets.

Interest Rate Swap Agreements

Fair Value Hedges

At December 31, 2004 and 2003, the Company had three outstanding interest rate swap agreements that qualified as fair value hedges: (i) OG&E entered into an interest rate swap

agreement, effective March 30, 2001, to convert $110.0 million of 7.30 percent fixed rate debt due October 15, 2025, to a variable rate based on the three month London InterBank Offering Rate ("LIBOR") and (ii) Enogex entered into two separate interest rate swap agreements, effective July 15, 2002 and October 24, 2002, to convert a total of $200.0 million ($100.0 million for each interest rate swap agreement) of 8.125 percent fixed rate debt due January 15, 2010, to a variable rate based on the six month LIBOR in arrears. The objective of these interest rate swaps was to achieve a lower cost of debt and to raise the percentage of total corporate long-term floating rate debt to reflect a level more in line with industry standards. These interest rate swaps qualified as fair value hedges 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.

At December 31, 2004 and 2003, the fair values pursuant to the interest rate swaps were approximately $7.9 million and $7.6 million, respectively, and the hedges were classified as Deferred Charges and Other Assets – Price Risk Management in the Consolidated Balance Sheets. A corresponding net increase of approximately $7.9 million and $7.6 million was reflected in Long-Term Debt at December 31, 2004 and 2003, respectively, as these fair value hedges were effective at December 31, 2004 and 2003.

Cash Flow Hedges

The Company entered into four separate interest rate swap agreements, effective April 16, 2004, April 21, 2004, May 17, 2004 and July 16, 2004, respectively, to hedge approximately $20.0 million, $30.0 million, $20.0 million and $10.0 million, respectively, of future interest payments of long-term debt that was issued in November 2004. See Note 1 for a further discussion of these interest rate swap agreements.

Long-term Debt Maturities

During 2004 and 2003, approximately $51.0 million and $19.0 million, respectively, of Enogex's long-term debt matured and approximately $10.3 million and $12.0 million, respectively, was redeemed during 2004 and 2003 which is itemized in the following table.

(In millions)	**2004**	2003
Series Due 2003 -- 6.60% - 8.28%	**$ ---**	$ 19.0
Series Due 2004 -- 6.71% - 8.34%	**51.0**	---
Series Due 2018 -- 7.15%	**2.0**	2.0
Series Due 2020 -- 7.00%	**8.3**	---
Series Due 2023 -- 7.75%	---	10.0
Total	**$ 61.3**	$ 31.0

Maturities of the Company's long-term debt during the next five years consist of $146.1 million in 2005; $1.8 million in 2006; $4.8 million in 2007; $2.8 million in 2008 and $1.8 million in 2009. For OG&E, $110.0 million of long-term debt matures in 2005; however, in the Consolidated Statement of Capitalization at December 31, 2004, no amount is shown as Long-Term Debt Due Within One Year. The Company plans to refinance this amount and the Company believes they have the ability to do so as the Company and OG&E entered into new

five-year revolving credit agreements in October 2004 in an amount up to $550 million which could be utilized to temporarily finance these notes when they mature in October 2005.

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

14. Short-Term Debt

The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by loans under short-term bank facilities. The maximum and average amounts of short-term borrowings during 2004 on a consolidated basis were approximately $216.1 million and $44.7 million, respectively, at a weighted average interest rate of 2.91 percent. The weighted average interest rates for 2003 and 2002 were 1.67 percent and 2.40 percent, respectively.

The short-term debt balance was approximately $125.0 million and $202.5 million at December 31, 2004 and 2003, respectively. The balance at December 31, 2003 was primarily due to the incurrence of short-term debt in anticipation of the expected 2003 year-end closing of the acquisition of the McClain Plant, which was completed on July 9, 2004. In conjunction with the acquisition of the McClain Plant, the Company issued short-term debt to fund a portion of the acquisition, and, as a result, the short-term debt balance was approximately $216.1 million at July 31, 2004. On August 4, 2004, OG&E issued $140.0 million of long-term debt to replace these short-term borrowings. During October 2004, the Company issued approximately $170.0 million in commercial paper related to the redemption of the trust preferred securities, of which approximately $100.0 million was refinanced in November 2004 by the issuance of long-term debt. See Note 18 for a further discussion of the recent McClain Plant acquisition.

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

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

Entity	Amount Available	Amount Outstanding	Maturity
OGE Energy Corp.	$ 15.0	$ ---	April 6, 2004
OG&E	100.0	---	October 20, 2009 (B)
OGE Energy Corp. (A)	450.0	---	October 20, 2009 (B)
	565.0	---	
Cash	26.4	N/A	N/A
Total	$ 591.4	$ ---	

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

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

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

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

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

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

During 2004 and 2003, the Company made contributions to the pension plan and the restoration of retirement income plan that exceeded amounts previously recognized as net periodic pension expense and recorded a net prepaid benefit obligation at December 31, 2004 and 2003 of approximately $92.0 million and $55.7 million, respectively. At December 31, 2004 and 2003, the Company’s projected pension benefit obligation exceeded the fair value of the pension plan assets and the restoration of retirement income plan assets by approximately $123.3 million and $131.8 million, respectively. As a result of recording a prepaid benefit obligation and having a funded status where the projected benefit obligations exceeded the fair value of plan assets, provisions of SFAS No. 87, “Employers’ Accounting for Pensions,” required the recognition of an additional minimum liability in the amount of approximately $156.6 million and $137.6 million, respectively, at December 31, 2004 and 2003. The offset of this entry was an intangible asset and Accumulated Other Comprehensive Income, net of a deferred tax asset; therefore, this adjustment did not impact the results of operations in 2004 or 2003 and did not require a usage of cash and is therefore excluded from the Consolidated 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 Consolidated Statements of Income in future periods.

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

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

Investment Policies and Strategies

The plan assets are held in a master trust which follows an investment policy and strategy designed to maximize the long-term investment returns of the master trust at prudent risk levels. Common stocks are used as a hedge against moderate inflationary conditions, as well as for participation in normal economic times. Fixed income investments are utilized for high current

income and as a hedge against deflation. The Company has retained an investment consultant responsible for the general investment oversight, analysis, monitoring investment guideline compliance and providing quarterly reports to certain of the Company’s members and the Company’s Employees’ Benefit Funds Management Requirements Committee (the “Committee”).

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

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

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

To evaluate the progress of the portfolio, investment performance is reviewed quarterly. It is, however, expected that performance goals will be met over a full market cycle, normally defined as a three to five year period. Analysis of performance is within the context of the prevailing investment environment and the advisors' investment style. The goal of the master trust is to provide a rate of return consistently from three to five percent over the rate of inflation (as measured by the national Consumer Price Index) over a typical market cycle of no less than three years and no more than five years. Each investment manager is expected to outperform its respective benchmark. Below is a list of each asset class utilized with appropriate comparative benchmark(s) each manager is evaluated against:

Asset Class	Comparative Benchmark(s)
Fixed Income	Lehman Aggregate Index
Value Equity	Russell 1000 Value Index - Short-term
	S&P 500 Index - Long-term
Growth Equity	Russell 1000 Growth Index - Short-term
	S&P 500 Index - Long-term
Mid-Cap Equity	Russell Midcap Index
Small-Cap Equity	Russell 2000 Index
Global Equity	Morgan Stanley Capital International Europe, Australia and Far East Index

The fixed income manager is expected to use discretion over the asset mix of the master trust assets in its efforts to maximize risk-adjusted performance. Exposure to any single issuer,

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

The domestic value equity managers focus on stocks that the manager believes are undervalued in price and earn an average or less than average return on assets, and often pays out higher than average dividend payments. The domestic growth equity manager will invest primarily in growth companies which consistently experience above average growth in earnings and sales, earn a high return on assets, and reinvest cash flow into existing business. The mid-cap equity portfolio manager focuses on companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell Midcap, small dividend yield, return on equity at or near the Russell Midcap and earnings per share growth rate at or near the Russell Midcap. The small-capitalization equity manager will purchase shares of companies with market capitalizations lower that the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell 2000, small dividend yield, return on equity at or near the Russell 2000 and earnings per share growth rate at or near the Russell 2000. The global equity manager invests primarily in non-dollar denominated equity securities. Investing internationally diversifies the overall master trust across the global equity markets. The manager is required to operate under certain restrictions including: regional constraints, diversification requirements and percentage of U.S. securities. The Morgan Stanley Capital International Europe, Australia and the Far East Index ("EAFE") 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.

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

unless prior approval of the Committee is received. The purchase of equity or debt issues of the portfolio manager's organization is also prohibited unless prior approval of the Committee is received.

Restoration of Retirement Income Plan

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

Postretirement Benefit Plans

In addition to providing pension benefits, the Company provides certain medical and life insurance benefits for eligible retired members ("postretirement benefits"). Regular, full-time, active employees hired prior to February 1, 2000, whose age and years of service total or exceed 80 or have attained age 55 with 10 years of service at the time of retirement are entitled to these postretirement benefits. Employees hired after January 31, 2000, are not entitled to postretirement medical benefits but are entitled to postretirement life insurance benefits. Eligible retirees must contribute such amount as the Company 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. OG&E 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 Consolidated Balance Sheets are as follows:

Projected Benefit Obligations

	Pension Plan and Restoration of Retirement Income Plan		Postretirement Benefit Plans	
(In millions)	**2004**	2003	**2004**	2003
Beginning obligations	**$ (485.4)**	$ (443.0)	**$ (181.1)**	$ (183.1)
Service cost	**(16.9)**	(15.2)	**(3.0)**	(3.0)
Interest cost	**(29.7)**	(29.2)	**(11.1)**	(10.9)
Participants' contributions	**---**	---	**(3.0)**	(2.2)
Plan changes/other	**(7.2)**	(4.0)	**---**	---
Actuarial gains (losses)	**(56.0)**	(42.3)	**(7.0)**	6.6
Benefits paid	**47.0**	48.3	**12.9**	11.5
Ending obligations	**$ (548.2)**	$ (485.4)	**$ (192.3)**	$ (181.1)

Fair Value of Plans' Assets

	Pension Plan and Restoration of Retirement Income Plan		Postretirement Benefit Plans	
(In millions)	**2004**	2003	**2004**	2003
Beginning fair value	**$ 353.6**	$ 286.3	**$ 56.0**	$ 46.0
Actual return on plans' assets	**46.6**	65.6	**9.3**	10.0
Employer contributions	**71.7**	50.0	**8.6**	9.3
Participants' contributions	**---**	---	**3.0**	2.2
Benefits paid	**(47.0)**	(48.3)	**(12.9)**	(11.5)
Ending fair value	**$ 424.9**	$ 353.6	**$ 64.0**	$ 56.0

Net Periodic Benefit Cost

(In millions)	Pension Plan and Restoration of Retirement Income Plan 2004	2003	2002	Postretirement Benefit Plans 2004	2003	2002
Service cost	**$ 16.9**	$ 15.2	$ 13.3	**$ 3.0**	$ 3.0	$ 2.7
Interest cost	**29.7**	29.2	28.7	**11.1**	10.9	9.6
Return on plan assets	**(31.6)**	(24.3)	(26.9)	**(5.5)**	(5.5)	(5.6)
Amortization of transition obligation	**---**	---	---	**2.7**	2.7	2.7
Amortization of net loss	**11.9**	13.2	4.7	**4.9**	3.4	0.5
Amortization of unrecognized prior service cost	**6.3**	5.8	5.4	**2.1**	2.1	2.1
Net periodic benefit cost	**$ 33.2**	$ 39.1	$ 25.2	**$ 18.3**	$ 16.6	$ 12.0

The capitalized portion of the net periodic pension benefit cost was approximately $8.4 million, $5.8 million and $4.0 million at December 31, 2004, 2003 and 2002, respectively. The capitalized portion of the net periodic postretirement benefit cost was approximately $5.0 million, $2.6 million and $2.0 million at December 31, 2004, 2003 and 2002, respectively.

Funded Status of Plans

(In millions)	Pension Plan and Restoration of Retirement Income Plan 2004	2003	Postretirement Benefit Plans 2004	2003
Funded status of the plans	**$ (123.3)**	$ (131.8)	**$ (128.3)**	$ (125.1)
Unrecognized net loss	**175.6**	146.6	**63.4**	65.1
Unrecognized prior service cost	**39.7**	40.9	**9.2**	11.2
Unrecognized transition obligation	**---**	---	**22.0**	24.7
Net amount recognized	**$ 92.0**	$ 55.7	**$ (33.7)**	$ (24.1)

Amounts recognized in the Consolidated Balance Sheets consist of:

(In millions)	Pension Plan and Restoration of Retirement Income Plan 2004	2003
Prepaid benefit obligation	**$ 92.7**	$ 55.7
Accrued pension and benefit obligations	**(157.3)**	(137.6)
Intangible asset - unamortized prior service cost	**38.0**	40.2
Accumulated deferred tax asset	**45.9**	37.7
Accumulated other comprehensive loss, net of tax	**72.7**	59.7
Net amount recognized	**$ 92.0**	$ 55.7

Rate Assumptions

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

Ultimate trend year	**N/A**	N/A	N/A	**2010**	2010	2010

N/A - not applicable

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

The Company expects to pay benefits related to its pension plan and restoration of retirement income plan of approximately $59.5 million in 2005, $58.8 million in 2006, $56.0 million in 2007, $58.9 million in 2008, $60.8 million in 2009 and $288.7 million in years 2010 to 2014. These expected benefits were based on the same assumptions used to measure the Company's benefit obligation at the end of the year and include benefits attributable to estimated future employee service.

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

ONE-PERCENTAGE POINT INCREASE

(In millions)	**2004**	2003	2002
Effect on aggregate of the service and interest cost components	**$ 1.9**	$ 1.9	$ 1.6
Effect on accumulated postretirement benefit obligations	**24.2**	23.1	23.2

ONE-PERCENTAGE POINT DECREASE

(In millions)	**2004**	2003	2002
Effect on aggregate of the service and interest cost components	**$ 1.5**	$ 1.5	$ 1.3
Effect on accumulated postretirement benefit obligations	**19.8**	18.9	19.0

Medicare Prescription Drug, Improvement and Modernization Act of 2003

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Medicare Act"). The Medicare Act expanded Medicare to include, for the first time, coverage for prescription drugs. Due to various uncertainties related to the Company's response to this legislation in relation to its postretirement medical plan and the appropriate accounting methodology for this event, the Company elected to defer financial recognition of this legislation until the FASB issued final accounting guidance. This deferral election was permitted under FASB Staff Position No. FAS 106-1, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." In May 2004, the FASB issued FASB Staff Position No. FAS 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003." FAS 106-2 provides guidance on the accounting for the effects of the Medicare Act for employers that sponsor postretirement heath care plans that provide prescription drug benefits. FAS 106-2 also requires those employers to provide certain disclosures regarding the effect of the federal subsidy provided by the Medicare Act. For employers who elected to defer financial recognition, FAS 106-2 provides two alternative methods of adoption which include a retroactive application to the date of the Medicare Act's enactment or a prospective application as of the date of adoption. For employers who elected not to defer financial recognition, FAS 106-2 requires these employers to recognize a cumulative effect of a change in accounting principle in accordance with APB Opinion No. 20. Adoption of FAS 106-2 is required for financial statements issued for periods beginning after June 15, 2004. The Company 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 the Company's postretirement medical plan will be reduced by approximately $13.3 million as a result of savings to the Company's postretirement medical plan resulting from the Medicare Act, which will reduce the Company's costs for its postretirement medical plan by approximately $2.5 million annually. The $2.5 million in annual savings is comprised of a reduction of approximately $1.5 million from amortization of the $13.3 million gain due to the reduction of the APBO, a reduction in the interest cost on the APBO of approximately $0.8 million and a reduction in the service cost due to the subsidy of approximately $0.2 million.

The Company expects to pay gross benefits payments related to its postretirement benefit plans, including prescription drug benefits, of approximately $11.3 million in 2005, $11.2 million in 2006, $11.2 million in 2007, $11.9 million in 2008, $12.5 million in 2009 and $71.5 million in years 2010 to 2014. The Company expects to receive subsidy receipts related to its postretirement benefit plans of approximately $0.5 million in 2006, $0.6 million in 2007, $0.6 million in 2008, $0.7 million in 2009 and $4.0 million in years 2010 to 2014. The Company does not expect to receive any subsidy receipts in 2005.

Defined Contribution Plan

The Company provides a defined contribution savings plan. Each regular full-time employee of the Company or an affiliate is eligible to participate in the plan immediately. All other employees of the Company 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." The Company 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, the Company shall contribute 100 percent of the Regular Contributions deposited during such pay period by such participant. No Company 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, special lump-sum recognition awards and lump-sum merit awards included in compensation for determining the amount of participant contributions. The Company's contribution which is allocated for investment to the OGE Energy Corp. Common Stock Fund may be made in shares of the Company's common stock or in cash which is used to invest in the Company's common stock. The Company contributed approximately $6.2 million, $5.6 million and $5.2 million during 2004, 2003 and 2002, respectively, to the defined contribution plan.

Deferred Compensation Plan

The Company 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 the Company 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. The Company 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. The Company accounts for the contributions in this plan as Accrued Pension and Benefit Obligations and Other Deferred Credits and the investment associated with these contributions is accounted for as Other Property and Investments in the Consolidated Balance Sheets. The appreciation of these investments is accounted for as Other Income and the increase in the liability under the plan is accounted for as Other Expense in the Consolidated Statements of Income.

Supplemental Executive Retirement Plan

The Company provides a supplemental executive retirement plan in order to attract and retain lateral hires or other executives designated by the Compensation Committee of the Company's Board of Directors who may not otherwise qualify for a sufficient level of benefits under the Company'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.

16. Report of Business Segments

The Company's Electric Utility operations are conducted through OG&E, a regulated utility engaged in the generation, transmission, distribution and sale of electric energy. The Company's Natural Gas Pipeline operations are conducted through Enogex. Enogex is engaged in the transportation and storage of natural gas, the gathering and processing of natural gas and the marketing of natural gas. Enogex also has been involved in investing in the development for and production of natural gas and crude oil, which investments Enogex sold during 2002. For the year ended December 31, 2002, Other Operations primarily includes unallocated corporate expenses, interest expense on the trust preferred securities and interest expense on commercial paper. As a result of the adoption of FASB Interpretation No. 46 on December 31, 2003, and the resulting deconsolidation of the trust preferred securities and the consolidation of MBP 19, Other Operations for the year ended December 31, 2003 primarily includes unallocated corporate expenses, interest expense to unconsolidated affiliate, interest expense on commercial paper and MBP 19. However, MBP 19 was deconsolidated during the first quarter of 2004. See Note 2 for a further discussion of the accounting for MBP 19. Therefore, Other Operations for the year ended December 31, 2004 primarily includes unallocated corporate expenses, interest expense to unconsolidated affiliate, interest expense on commercial paper and interest expense on long-term debt. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. The following tables summarize the results of the Company's business segments for the years ended December 31, 2004, 2003 and 2002.

2004	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	**$ 1,578.1**	**$ 3,443.9**	**$ ---**	**$ (95.4)**	**$ 4,926.6**
Fuel	**645.4**	**---**	**---**	**(49.5)**	**595.9**
Purchased power	**269.1**	**---**	**---**	**---**	**269.1**
Gas and electricity purchased for resale (B)	**---**	**3,054.3**	**---**	**(45.2)**	**3,009.1**
Natural gas purchases - other	**---**	**88.6**	**---**	**---**	**88.6**
Cost of goods sold	**914.5**	**3,142.9**	**---**	**(94.7)**	**3,962.7**
Gross margin on revenues	**663.6**	**301.0**	**---**	**(0.7)**	**963.9**
Other operation and maintenance	**301.9**	**101.5**	**(11.2)**	**---**	**392.2**
Depreciation	**122.7**	**47.6**	**8.3**	**---**	**178.6**
Impairment of assets	**---**	**7.8**	**---**	**---**	**7.8**
Taxes other than income	**47.0**	**17.5**	**3.3**	**---**	**67.8**
Operating income (loss)	**192.0**	**126.6**	**(0.4)**	**(0.7)**	**317.5**

Other income		**6.1**		**4.5**		**1.5**		**---**		**12.1**
Other expense		**(2.7)**		**(0.7)**		**(2.1)**		**---**		**(5.5)**
Interest income		**2.7**		**3.5**		**1.3**		**(2.3)**		**5.2**
Interest expense		**(37.5)**		**(37.5)**		**(23.4)**		**2.3**		**(96.1)**
Income tax expense (benefit)		**53.0**		**36.2**		**(8.7)**		**(0.3)**		**80.2**
Income (loss) from continuing operations		**107.6**		**60.2**		**(14.4)**		**(0.4)**		**153.0**
Income from discontinued operations		**---**		**0.5**		**---**		**---**		**0.5**
Net income (loss)	**$**	**107.6**	**$**	**60.7**	**$**	**(14.4)**	**$**	**(0.4)**	**$**	**153.5**
Total assets	**$**	**3,084.2**	**$**	**1,807.7**	**$**	**1,731.5**	**$**	**(1,753.1)**	**$**	**4,870.3**
Capital expenditures	**$**	**391.2**	**$**	**32.1**	**$**	**8.5**	**$**	**---**	**$**	**431.8**

(A) Natural Gas Pipeline’s operations consist of three related businesses: Transportation and Storage, Gathering and Processing and Marketing. The following table provides supplemental Natural Gas Pipeline information.

2004		Transportation and Storage		Gathering and Processing		Marketing		Eliminations		Total
(In millions)										
Operating revenues	**$**	**326.8**	**$**	**566.7**	**$**	**3,056.1**	**$**	**(505.7)**	**$**	**3,443.9**
Operating income	**$**	**60.9**	**$**	**56.2**	**$**	**9.5**	**$**	**---**	**$**	**126.6**

(B) OERI exited the power marketing business during the first quarter of 2004.

2003		Electric Utility		Natural Gas Pipeline (A)		Other Operations		Intersegment		Total
(In millions)										
Operating revenues	$	1,517.1	$	2,327.8	$	---	$	(65.9)	$	3,779.0
Fuel		544.5		---		---		(44.7)		499.8
Purchased power		292.9		---		---		---		292.9
Gas and electricity purchased for resale		---		2,019.1		---		(21.2)		1,997.9
Natural gas purchases - other		---		55.4		---		---		55.4
Cost of goods sold		837.4		2,074.5		---		(65.9)		2,846.0
Gross margin on revenues		679.7		253.3		---		---		933.0
Other operation and maintenance		294.8		91.2		(14.3)		---		371.7
Depreciation		121.8		44.2		10.9		---		176.9
Impairment of assets		---		9.2		1.0		---		10.2
Taxes other than income		46.9		17.5		2.9		---		67.3
Operating income (loss)		216.2		91.2		(0.5)		---		306.9
Other income		0.8		6.6		0.7		---		8.1
Other expense		(3.2)		(3.0)		(2.8)		---		(9.0)
Interest income		0.6		0.9		1.7		(1.9)		1.3
Interest expense		(38.8)		(39.8)		(21.3)		1.9		(98.0)
Income tax expense (benefit)		60.2		22.7		(9.2)		---		73.7
Income (loss) from continuing operations		115.4		33.2		(13.0)		---		135.6
Loss from discontinued operations		---		(0.4)		---		---		(0.4)
Income (loss) before cumulative effect of change in accounting principle		115.4		32.8		(13.0)		---		135.2
Cumulative effect on prior years of change in accounting principle, net of tax		---		(5.9)		0.5		---		(5.4)
Net income (loss)	$	115.4	$	26.9	$	(12.5)	$	---	$	129.8

Total assets	$ 2,775.2	$ 1,585.6	$ 1,745.2	$ (1,521.3)	$ 4,584.7
Capital expenditures	$ 148.7	$ 28.1	$ 4.5	$ ---	$ 181.3

(A) Natural Gas Pipeline's operations consist of three related businesses: Transportation and Storage, Gathering and Processing and Marketing. The following table provides supplemental Natural Gas Pipeline information.

2003	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	$ 249.0	$ 512.0	$ 1,964.0	$ (397.2)	$ 2,327.8
Operating income	$ 64.2	$ 14.0	$ 13.0	$ ---	$ 91.2

2002	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	$ 1,388.0	$ 1,684.0	$ ---	$ (48.1)	$ 3,023.9
Fuel	435.8	---	---	(33.6)	402.2
Purchased power	260.0	---	---	---	260.0
Gas and electricity purchased for resale	---	1,402.1	---	(14.5)	1,387.6
Natural gas purchases - other	---	70.5	---	---	70.5
Cost of goods sold	695.8	1,472.6	---	(48.1)	2,120.3
Gross margin on revenues	692.2	211.4	---	---	903.6
Other operation and maintenance	282.9	101.1	(14.0)	---	370.0
Depreciation	123.1	49.3	10.1	---	182.5
Impairment of assets	---	48.3	1.8	---	50.1
Taxes other than income	47.1	15.7	2.5	---	65.3
Operating income (loss)	239.1	(3.0)	(0.4)	---	235.7
Other income	0.7	1.5	1.5	---	3.7
Other expense	(3.1)	(0.6)	(1.0)	---	(4.7)
Interest income	1.2	1.1	19.1	(19.7)	1.7
Interest expense	(40.2)	(49.7)	(40.6)	19.7	(110.8)
Income tax expense (benefit)	71.6	(19.2)	(7.8)	---	44.6
Income (loss) from continuing operations	126.1	(31.5)	(13.6)	---	81.0
Income from discontinued operations	---	9.8	---	---	9.8
Net income (loss)	$ 126.1	$ (21.7)	$ (13.6)	$ ---	$ 90.8
Total assets	$ 2,659.9	$ 1,532.6	$ 1,820.3	$ (1,747.9)	$ 4,264.9
Capital expenditures	$ 198.7	$ 20.0	$ 14.8	$ 1.0	$ 234.5

(A) Natural Gas Pipeline's operations consist of three related businesses: Transportation and Storage, Gathering and Processing and Marketing. The following table provides supplemental Natural Gas Pipeline information.

2002	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	$ 444.6	$ 179.0	$ 1,350.5	$ (290.1)	$ 1,684.0
Operating income (loss)	$ 45.6	$ (49.5)	$ 0.9	$ ---	$ (3.0)

17. Commitments and Contingencies

Capital Expenditures

The Company's capital expenditures are estimated at approximately: 2005 – $280.0 million, 2006 – $250.9 million and 2007 — $230.4 million.

Operating Lease Obligations

The Company has operating lease obligations expiring at various dates, primarily for OG&E railcar leases (expiring March 31, 2006) and Enogex noncancellable operating leases. Future minimum payments for noncancellable operating leases are as follows:

(In millions)		2005		2006		2007		2008		2009		2010 and Beyond
Operating lease obligations												
OG&E railcars (A)	$	5.4	$	5.4	$	5.3	$	5.4	$	5.3	$	24.9
Enogex noncancellable operating leases		3.7		3.2		0.9		0.1		0.1		0.1
Total operating lease obligations	$	9.1	$	8.6	$	6.2	$	5.5	$	5.4	$	25.0

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

Payments for operating lease obligations were approximately $9.7 million, $9.8 million and $10.6 million in 2004, 2003 and 2002, respectively.

OG&E Railcar Leases

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

OG&E 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 OG&E to purchase power generated in a manufacturing process from a qualified cogeneration facility ("QF"). The rate for such power to be paid by OG&E was approved by the OCC. The rate generally consists of two components: one is a rate for actual electricity purchased from the QF by OG&E; the other is a capacity charge, which OG&E must pay the QF for having the capacity available. However, if no electrical power is made available to OG&E for a period of time (generally three months), OG&E's obligation to pay the capacity charge is suspended. The total cost of cogeneration payments is recoverable in rates from customers.

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

Fuel Minimum Purchase Commitments

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

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

Natural Gas Units

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

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

In 1998, Enogex entered into a Storage Lease Agreement (the “Agreement”) with Central Oklahoma Oil and Gas Corp. (“COOG”). Under the Agreement, COOG agreed to make certain enhancements to the Stuart Storage Facility to increase capacity and deliverability of the facility. In 1999 a dispute arose as to whether the natural gas deliverability for the Stuart Storage Facility was being provided by COOG and these issues were submitted to arbitration in October and November 2001. In July 2002, the Oklahoma District Court affirmed the arbitration award and entered judgment against COOG and in favor of Enogex in the amount of approximately $23.3 million (the “Judgment”).

On July 24, 2002, Enogex exercised the asset purchase option provided in the Agreement and title to the Stuart Storage Facility was transferred to Enogex on October 24, 2002, effective August 9, 2002 (the date COOG turned over operations of the facility to Enogex). As part of the Agreement, the Company agreed in 1998 to make up to a $12 million secured loan to Natural Gas Storage Corporation (“NGSC”), an affiliate of COOG (the “NGSC Loan”). NGSC failed and refused to repay the NGSC Loan.

On August 12, 2002, the Company received a petition in a legal proceeding filed by COOG and NGSC against the Company and Enogex in Texas. COOG and NGSC stated a claim for declaratory judgment asserting, among other things, that NGSC is not obligated to make payments on the NGSC Loan based on various theories and, that: (1) the Company was obligated to demand Enogex make the requisite payments to the Company; (2) the Company is liable to NGSC for failing to demand the requisite payments from Enogex, or alternatively, NGSC is entitled to a reduction in the amount it owes to the Company; (3) Enogex was and is obligated to make the payments to the Company until the indebtedness of NGSC to the Company is reduced to zero; (4) Enogex is not entitled to set off the Judgment against the lease payments that it originally owed to COOG and now owes to the Company; (5) no event of default has occurred; and (6) under the Agreement, the only remedy Enogex had or has if the Stuart Storage Facility did not perform was to seek a modification of the lease payments based upon COOG’s expert’s analysis of the performance of the Stuart Storage Facility. COOG and NGSC have also stated claims for breach of contract relating to the same allegations in its claim for declaratory relief and include claims for attorneys’ fees.

The Company objected to being sued in Texas because the Texas Court does not have proper jurisdiction over the Company. In 2002, Enogex responded to the allegations, asserting, among other things, that the disputed issues have already been properly determined by the Arbitration Panel and the Oklahoma Court and, therefore, this action is improper.

By order dated June 19, 2003, the Texas Court granted Enogex’s request for arbitration and ordered COOG, NGSC and Enogex to arbitration. The parties participated in the Oklahoma County arbitration in May 2004 and the arbitration panel rendered a decision in the Company’s favor for approximately $5.0 million related to the outstanding NGSC Loan on July 15, 2004 and this judgment is final.

In 2003, the Company and Enogex brought separate complaints against the individual shareholders of COOG and NGSC – Enogex Inc. v John C. Thrash, John F. Thrash and Robert R. Voorhees, Jr., Case No. CIV-03-0388-L; and OGE Energy Corp. and Enogex Inc. v John C. Thrash, John F. Thrash and Robert R. Voorhees, Jr., Case No. CIV 03-0389-L – both filed in the Western District of Oklahoma Federal Court. The Company and Enogex each stated claims for (1) fraudulent transfer; (2) imposition of an equitable trust; and (3) breach of fiduciary duty. A jury trial was held from October 12 – 26, 2004. The case was submitted to the jury on October 25, 2004 and the jury ruled in favor of the Company and Enogex for approximately $6.6 million. The individual defendants have filed a motion for new trial, which is currently pending before the Court. Also in the Texas case, on October 4, 2004, the plaintiffs filed a first amended petition seeking: (i) declaratory judgment based on collusion to impair collateral; (ii) gross negligence; and (iii) declaratory judgment and confirmation of certain aspects of the arbitration award. The plaintiffs have added a request for punitive damages. A motion to strike the amended petition or alternatively refer any remaining issues to arbitration under the parties’ agreement has been filed by Enogex and the Company. The plaintiffs filed a motion to dismiss Enogex from the suit which the court granted by order dated January 26, 2005. Enogex has objected to this ruling and has requested reconsideration of the court’s ruling to properly reserve the previous rulings in this matter. A determination relating to the jurisdiction by the Texas court of the Company is pending before the court.

The Company intends to continue to vigorously pursue its rights in conjunction with the remaining amounts owed under the judgments, plus interest.

Natural Gas Measurement Cases

United States of America ex rel., Jack J. Grynberg v. Enogex Inc., Enogex Services Corporation and OG&E. (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 (“Btu”) content) purchased from federal and Indian lands which have resulted in the under-reporting and underpayment of gas royalties owed to the Federal Government; (ii) certain provisions generally found in gas purchase contracts are improper; (iii) transactions by affiliated companies are not arms-length; (iv) excess processing cost deduction; and (v) failure to account for production separated out as a result of gas processing. Grynberg seeks the following damages: (a) additional royalties which he claims should have been paid to the Federal Government, some percentage of which Grynberg, as relator, may be entitled to recover; (b) treble damages; (c) civil penalties; (d) an order requiring defendants to measure the way Grynberg contends is the better way to do so; and (e) interest, costs and attorneys’ fees.

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

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

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

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

Will Price (Price I) – On September 24, 1999, various subsidiaries of the Company 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, OG&E and Enogex Inc. were omitted from the case. Two subsidiaries of Enogex remain as defendants. The Plaintiffs' amended petition alleges that approximately 60 defendants, including two Enogex subsidiaries, have improperly measured natural gas. The amended petition reduces the claims to: (1) mismeasurement of volume only; (2) conspiracy, unjust enrichment and accounting; (3) a putative Plaintiffs' class of only royalty owners; and (4) gas measured in three specific states. Discovery on class certification is proceeding. A hearing on class certification issues is set for April 1, 2005.

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

Will Price (Price II) – On May 12, 2003, the Plaintiffs (same as those in Price I above) filed a new class action petition (Price II) in the District Court of Stevens County, Kansas, relating to wrongful Btu analysis against natural gas pipeline owners and operators, naming the same defendants as in the amended petition of the Price I case. Two Enogex subsidiaries were

served on August 4, 2003. The Plaintiffs seek to represent a class of only royalty owners either from whom the defendants had purchased natural gas or measured natural gas since January 1, 1974 to the present. The class action petition alleges improper analysis of gas heating content. In all other respects, the Price II petition appears to be the same as the amended petition in Price I. Discovery on class certification is proceeding. A hearing on class certification issues is set for April 1, 2005.

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

Agreement with Colorado Interstate Gas Company

In December 2002, Enogex entered into an agreement with Colorado Interstate Gas Company regarding reservation of firm capacity on an interstate gas pipeline that was initially proposed to be in service by August 31, 2005 (the "Cheyenne Plains Pipeline"). Under the final transportation agreement, OERI reserved 60,000 decatherms/day ("Dth/day") of capacity on the pipeline for 10 years and two months. Such reservation provides OERI access to significant additional natural gas supplies in the Rocky Mountain production basins. The Cheyenne Plains Pipeline, which began full service in February 2005, provides interstate gas transportation services in Wyoming, Colorado and Kansas with a capacity of 560,000 Dth/day. OERI pays a demand fee of approximately $7.5 million annually for this capacity. Also, Enogex expects a loss of approximately $3.0 million in 2005 related to its Cheyenne Plains' position as a result of unfavorable market conditions for the capacity primarily due to an earlier than expected in-service date for the project and the associated lack of upstream gas supply and pipeline infrastructure to deliver gas to the Cheyenne hub for 2005.

Guarantees

At December 31, 2004, in the event Moody's or Standard & Poor's were to lower Enogex's senior unsecured debt rating to a below investment grade rating, Enogex would be required to post approximately $8.2 million of collateral to satisfy its obligation under its financial and physical contracts.

Environmental Laws and Regulations

Approximately $7.0 million of the Company's capital expenditures budgeted for 2005 are to comply with environmental laws and regulations. The Company's management believes that all of its operations are in substantial compliance with present federal, state and local environmental standards. It is estimated that the Company's total expenditures for capital, operating, maintenance and other costs to preserve and enhance environmental quality will be approximately $57.8 million during 2005, compared to approximately $57.1 million in 2004. The Company continues to evaluate its environmental management systems to ensure compliance with existing and proposed environmental legislation and regulations and to better position itself in a competitive market.

OG&E

Air

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

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

Other potential air regulations also have emerged that could impact OG&E. On December 15, 2003, the Environmental Protection Agency ("EPA") proposed regulations to limit mercury emissions from coal-fired boilers. This rule is expected to be finalized by early 2005. Earliest compliance by OG&E would be 2008. Depending upon the final regulations, this could result in significant capital and operating expenditures. In addition, on January 30, 2004, the EPA proposed a Clean Air Interstate Rule. This rule is intended to control SO2 and NOX from utility boilers in order to minimize the interstate transport of air pollution. The State of Oklahoma, however, is not listed as one of the states affected by the proposed rule. This, however, could change as the EPA has indicated its intentions to review Oklahoma's impact on other states. If Oklahoma is included in the final rule reductions, this could lead to significant capital and operating expenditures by OG&E.

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

In 1999, the EPA first issued regulations concerning regional haze. These regulations are intended to protect visibility in national parks and wilderness areas throughout the United States. In Oklahoma, the Wichita Mountains would be the only area covered under the regulation. However, Oklahoma's impact on parks in other states must also be evaluated. Sulfates and nitrate aerosols (both emitted from coal-fired boilers) can lead to the degradation of

visibility. The State of Oklahoma has joined with eight other central states and has begun the process of determining what, if any, impact emission sources in Oklahoma have on national parks and wilderness areas. This study will be complete and any compliance strategies adopted by January 2008. If an impact is determined, then significant capital expenditures could be required for both the Sooner and Muskogee generating stations.

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

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

With respect to the NOX regulations of Title IV of the CAAA, OG&E 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, OG&E was eligible to exercise its option to extend the effective date of the lower emission requirements from the year 2000 until 2008. OG&E's average NOX emissions from its coal-fired boilers for 2004 were 0.337 lbs/MMBtu. The regulations require that OG&E 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 OG&E's facilities impact the air quality of the Tulsa or Oklahoma City metropolitan areas, or if Oklahoma becomes non-attainment with the fine particulate standard. Any of these scenarios would require significant capital and operating expenditures.

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

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

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

Waste

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

Water

OG&E submitted one application during 2004 to renew an Oklahoma Pollutant Discharge Elimination System ("OPDES") permit. OG&E has received three renewed wastewater permits during 2004. All permits received to date have been reasonable in their requirements, allow operational flexibility and provide reductions in operating costs.

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

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

Enogex

The construction and operation of pipelines, plants and other facilities for gathering, processing, treating, transporting or storing natural gas and other products may be subject to

federal, state and local environmental laws and regulations, including those that can impose obligations to clean up hazardous substances at the locations at which Enogex operates. In most instances, the applicable regulatory requirements relate to water and air pollution control or solid waste management measures. Appropriate governmental authorities may enforce these laws and regulations with a variety of civil and criminal enforcement measures, including monetary penalties, assessment and remediation requirements and injunctions as to future compliance. Enogex generates some materials subject to the requirements of the Federal Resource Conservation and Recovery Act and the Clean Water Act and comparable state statutes, prepares and files reports and documents pursuant to the Toxic Substance Control Act and the Emergency Planning and Community Right to Know Act and obtains permits pursuant to the Federal Clean Air Act and comparable state air statutes.

Environmental regulation can increase the cost of planning, design, initial installation and operation of Enogex's facilities. Historically, Enogex's total expenditures for environmental control facilities and for remediation have not been significant in relation to its results of operations or financial condition. The Company believes, however, that it is reasonably likely that the trend in environmental legislation and regulations will continue to be towards stricter standards.

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

Other

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

18. Rate Matters and Regulation

Regulation and Rates

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

31, 2004, approximately 87 percent of OG&E'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 OG&E to reorganize into a subsidiary of the Company. The order required that, among other things, (i) the Company permit the OCC access to the books and records of the Company and its affiliates relating to transactions with OG&E; (ii) the Company employ accounting and other procedures and controls to protect against subsidization of non-utility activities by OG&E's customers; and (iii) the Company refrain from pledging OG&E assets or income for affiliate transactions.

Recent Regulatory Matters

2002 Settlement Agreement

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

OCC Order Confirming Savings

The Settlement Agreement required that, if OG&E did not acquire the New Generation by December 31, 2003, OG&E 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 OG&E 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, OG&E entered into a power purchase agreement with the McClain Plant that delivered the savings guaranteed to OG&E's customers. OG&E 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 OG&E would not be required to begin crediting its customers. On April 28, 2004, the OCC issued an order confirming that OG&E was delivering savings to its customers as required under the Settlement Agreement. The order removed any uncertainty over whether the OCC believed OG&E had to reduce its rates, effective January 1, 2004, while it awaited action by the FERC on its application to purchase the McClain Plant. A party to the OCC proceeding has appealed the OCC's order to the Oklahoma Supreme Court. OG&E currently believes that the appeal is without merit.

Recent Acquisition of Power Plant

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

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

The final approval OG&E had been waiting for was the approval from the FERC. On July 2, 2004, the FERC authorized OG&E to acquire the McClain Plant. The FERC's approval was based on an offer of settlement OG&E filed in a proceeding on March 8, 2004. Under the offer of settlement, OG&E proposed, among other things, to install certain new transmission facilities and to hire an independent market monitor to oversee OG&E's activity for a limited period. Two other parties, InterGen Services, Inc. and AES Shady Point, opposed OG&E's offer of settlement and filed competing settlement offers. In the July 2, 2004 order, the FERC: (i) approved OG&E's offer of settlement subject to conditions; (ii) rejected the competing offers of settlement; and (iii) approved OG&E's acquisition of the McClain Plant. As part of the July 2, 2004 order, OG&E agreed to undertake the following mitigation measures: (i) install a transformer at one of its facilities at a cost of approximately $9.3 million which was completed in the fourth quarter of 2004; (ii) provide a 600 MW bridge into its control area from the Redbud Energy LP ("Redbud") plant; and (iii) hire an independent market monitor to oversee OG&E's activity in its control area. The market monitoring plan is designed to detect any anticompetitive conduct by OG&E from operation of its generation resources or its transmission system. The market monitoring function is performed daily and periodic reviews are also performed. To date, the independent market monitor has filed two reports, one on October 13, 2004 covering the period from July 10, 2004 to September 30, 2004, and one on January 14, 2005 covering the period from October 1, 2004 to December 31, 2004. Based on an analysis of transmission

congestion data on OG&E's system, along with data on purchases and sales, generation dispatch data and power flows on OG&E's tie lines, the market monitor concluded that OG&E did not act in an anticompetitive manner through either dispatch of its generation or operation of its transmission system. Additionally, OG&E's operations under the ongoing mitigation measures that require OG&E to make available transmission capability available to the Redbud power plant for access to the OG&E system were analyzed. Based on this analysis, the market monitor concluded that OG&E has complied with this requirement. Further, in the review of the disposition of requests for transmission service, the independent market monitor detected no problems with access to OG&E's transmission system. OG&E expects to complete the installation and implementation of these measures by June 2005. One party has filed a request for rehearing of the FERC's July 2, 2004 order. The outcome of that request for rehearing cannot be determined at this time.

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

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

OG&E expects the acquisition of the McClain Plant, including the effects of an interim power purchase agreement OG&E had with NRG McClain LLC while OG&E was awaiting regulatory approval to complete the acquisition, will provide savings, over a three-year period, in excess of $75.0 million to its Oklahoma customers. These savings will be derived from: (i) the avoidance of purchase power contracts otherwise needed; (ii) an above market cogeneration contract with PowerSmith Cogeneration Project, L.P. ("PowerSmith") when it terminated at the end of August 2004; and (iii) fuel savings associated with operating efficiencies of the new

plant. These savings, while providing real savings to Oklahoma customers, are not expected to affect OG&E's profitability because its rates are not expected to be reduced to accomplish these savings. In the event OG&E is unable to demonstrate at least $75.0 million in savings to its customers during this 36-month period, OG&E will 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, OG&E believes that it will be able to demonstrate at least $75.0 million in savings during this period.

Contract with PowerSmith

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

FERC Section 311 2001 and 2004 Rate Cases and related FERC dockets

In December 2001, Enogex made a filing at the FERC under Section 311 of the Natural Gas Policy Act to establish rates, to establish a default processing fee and to address various other issues for the combined Enogex and Transok L.L.C. pipeline systems. In May 2003, the FERC accepted a stipulation and settlement agreement and entered an order modifying Enogex's SOC with respect to priority for dedicated gas. The settlement included a fee to be assessed under certain market conditions to process customer gas gathered behind processing plants so that it meets the heating value standards of natural gas transmission pipelines ("default processing fee"). This default processing fee, which decreases the volatility of Enogex's earnings stream by reducing Enogex's exposure to keep-whole processing arrangements, is implemented in the event the natural gas liquids revenue less the associated fuel and shrinkage costs is negative. Pursuant to Enogex's SOC that was effective through September 30, 2004, if Enogex's annual processing gross margin exceeds a specified threshold, Enogex is required to record a default processing fee refund obligation in an amount equal to the lesser of the default processing fees or the amount of the processing margin in excess of the specified threshold.

During the third and fourth quarters of 2003, the Company established approximately a $4.9 million reserve to cover such refund obligations. During April 2004, the Company refunded its default processing fee refund obligation under the SOC to the applicable customers. For the year ended December 31, 2004, the Company billed default processing fees of approximately $0.2 million, which has been recorded as deferred revenue. For the year ended December 31, 2003, the Company recorded net default processing fee revenue, that is, net of the $4.9 million reserve discussed above, of approximately $0.3 million. The Company records any default processing fees billed to customers as deferred revenue until it becomes probable that the processing gross margin threshold in Enogex's SOC will not be exceeded. Based on the 2004 processing gross margin, the default processing fees billed to customers in 2004 were recorded

as deferred revenue as the 2004 processing gross margin exceeded the 2004 processing gross margin threshold in the SOC. During April 2005, the Company expects to refund its 2004 default processing fee refund obligation under the SOC to the applicable customers. Also, during the years ended December 31, 2004 and 2003, respectively, the Company recognized revenue of approximately $0.5 million and $0.7 million of low flow meter charges.

On September 1, 2004, Enogex made a filing at the FERC to revise its previously approved SOC to permit, among other things, the unbundling, effective October 1, 2004, of its previously bundled gathering and transportation services. Thereafter, the FERC will regulate Enogex's Section 311 transportation and any regulation of gathering will be pursuant to Oklahoma statute. Several parties challenged the SOC changes and the filing is currently under review at the FERC. On September 30, 2004, Enogex made a filing at the FERC to update Enogex's Section 311 maximum transportation rate. Certain parties challenged aspects of the rate filing. In addition, on September 29, 2004, Enogex filed an updated fuel factor with the FERC for the last quarter of 2004. One party protested the fourth quarter 2004 fuel filing. The FERC Staff served data requests concerning the revised SOC, the rate filing, and the fourth quarter 2004 fuel filing on December 3, 2004. An initial technical conference in these dockets was held on January 13, 2005. At the conference, the parties agreed to brief one aspect of the Enogex filing now and to seek an extension of time for resolution of the filing in which to attempt to settle the rate case. Enogex and nearly all of the intervening parties filed a joint unopposed motion for an extension of time on January 25, 2005. Enogex and certain intervenors filed individual initial comments on January 26, 2005 and reply comments on February 2, 2005 seeking policy guidance from the FERC. The FERC has not yet acted on either the motion or the comments.

Finally, on November 15, 2004, Enogex filed an updated fuel factor for fuel year 2005 (calendar year 2005)**.** The filing is the annual filing made by Enogex that establishes the fixed fuel percentage for natural gas shipped on the Enogex system. One intervenor has challenged the annual fuel factor filing. There has been no discovery or FERC action on this annual fuel filing and the timing of such action is uncertain.

Security Enhancements

On April 8, 2002, OG&E 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, OG&E filed testimony with the OCC outlining proposed expenditures and related actions for security enhancement and a proposed recovery rider. Attempting to make security investments at the proper level, OG&E has developed a set of guidelines intended to minimize long-term or widespread outages, minimize the impact on critical national defense and related customers, maximize the ability to respond to and recover from an attack, minimize the financial impact on OG&E that might be caused by an attack and accomplish these efforts with minimal impact on ratepayers. The OCC Staff retained a security expert to review the report filed by OG&E. 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 OG&E's infrastructure; and (ii) a security rider should be authorized to recover costs as these projects are completed. On August 4, 2004, OG&E 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 OG&E's customers for security enhancement. The hearing in this case was held on November 9, 2004, at which time the administrative law judge approved the stipulation agreement between all parties. On December 21, 2004 the OCC issued an order approving the security rider.

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

Cogeneration Credit Rider

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

Pending Regulatory Matters

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

Gas Transportation and Storage Agreement

As part of the Settlement Agreement, OG&E also agreed to consider competitive bidding as a basis to select its provider for gas transportation service to its natural gas-fired generation facilities pursuant to the terms set forth in the Settlement Agreement. The prescribed bidding

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

On April 29, 2003, as required by the Settlement Agreement, OG&E filed an application with the OCC in which OG&E advised the OCC that, after careful consideration, competitive bidding for gas transportation was rejected in favor of a new intrastate 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 OG&E's natural gas-fired generation facilities. OG&E 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, OG&E supplies system fuel in-kind for its pro-rata share of actual fuel and loss and unaccounted for gas on the transportation system. To the extent OG&E transports gas in quantities in excess of the prescribed MDQs or MHQs, it pays an overrun service charge. During the years ended December 31, 2004, 2003 and 2002, OG&E paid Enogex approximately $49.6 million, $44.7 million and $36.9 million, respectively, for gas transportation and storage services.

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

OG&E filed rebuttal testimony on August 16, 2004 in this case. Hearings in this case before an administrative law judge occurred from September 16-22, 2004. On October 22, 2004, the administrative law judge overseeing the proceeding recommended approximately $41.9

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

Southwest Power Pool

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

Currently, the regional state committee, which is comprised of commissioners regulating the state regulatory jurisdictional SPP members, is in the process of formulating a methodology for funding transmission expansion in the SPP's control area by allocating costs of transmission expansion to the SPP members who benefit. The SPP plans to make a filing at the FERC in February 2005 related to this matter. Also, the SPP is in the process of developing a process, required by the FERC, to create an imbalance energy market which will require cash settlements for over or under generation. Each SPP member will be responsible for monitoring its generation in its control area on an hourly basis and periodically submitting this information to the SPP, who will then provide settlement statements to each of the SPP members. The imbalance energy market requirements are planned to be effective October 1, 2005.

FERC Standards of Conduct

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

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

On September 21, 2004, Ozark filed a request for clarification of the FERC's Order 2004 regulations to permit Ozark to share a common gas control group with its energy affiliates. Granting the request would eliminate the need for Ozark to establish a separate gas control group. On November 26, 2004, the FERC granted Ozark's request.

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

Market-Based Rate Authority

On December 22, 2003, OG&E and 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.

OG&E and OERI submitted a compliance filing to the FERC on February 7, 2005 which shows the impact of the new requirements on OG&E and OERI. In the compliance filing, OG&E and OERI passed the pivotal supplier screen but failed to pass the market share screen. OG&E 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. OG&E and OERI do not know when the FERC will act on the filing or what action the FERC will take.

Department of Energy Blackout Report

On April 5, 2004, the U.S. Department of Energy issued its final report regarding the August 14, 2003 electric blackout in the eastern United States, which did not have an adverse affect on OG&E'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 OG&E, 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, OG&E filed its report on vegetation management practices with the FERC. During 2004, OG&E spent less than $0.2 million related to the implementation of blackout report recommendations. Implementation of the blackout report recommendations and the FERC policy statement could increase future transmission costs, but the extent of the increased costs is not known at this time.

Redbud Tariff Filing

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

National Energy Legislation

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

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

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

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

Although efforts to increase competition at the state level have been stalled, there have been several initiatives implemented at the federal level to increase competition in the wholesale markets for electricity. The National Energy Policy Act of 1992 ("Energy Act"), among other things, promoted the development of independent power producers ("IPP"). The Energy Act was followed by FERC Order 888 and Order 889, which facilitated third-party utilization of the transmission grid for sales of wholesale power. The Energy Act, Orders 888 and 889, and other FERC policies and initiatives have significantly increased competition in the wholesale power

market. Utilities, including OG&E, have increased their own in-house wholesale marketing efforts and the number of entities with whom they historically traded. While power marketers became an increasingly important presence in the industry, their importance has declined following the bankruptcy of Enron and the financial troubles of other significant power marketers. These entities typically arbitrage wholesale price differentials by buying power produced by others in one market and selling it in another. IPPs also are becoming a more significant sector of the electric utility industry. In both Oklahoma and Arkansas, significant additions of new power plants have been announced and, in some cases completed, almost all of it from IPPs.

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

In July 2002, the FERC issued a Notice of Proposed Rulemaking on Standard Market Design Rulemaking for regulated utilities. If implemented as proposed, the rulemaking will substantially change how wholesale electric markets operate throughout the United States. The proposed rulemaking expands the FERC's intent to unbundle transmission operations from integrated utilities and ensure robust competition in wholesale markets. The proposed rule contemplates that all wholesale and retail customers will take transmission service under a single network transmission service tariff. The rule also contemplates the implementation of a bid-based system for buying and selling energy in wholesale markets. RTOs or Independent Transmission Providers will administer the market. RTOs will also be responsible for regional plans that identify opportunities to construct new transmission, generation or demand side programs to reduce transmission constraints and meet regional energy requirements. Finally, the rule envisions the development of Regional Market Monitors responsible for ensuring the individual participants do not exercise unlawful market power. On April 28, 2003, the FERC issued a White Paper, "Wholesale Market Platform", in which the FERC indicated that it will change the proposed rule as reflected in the White Paper and following additional regional technical conferences. The FERC committed in the White Paper to work with interested parties including state commissions to find solutions that will recognize regional differences within

regions subject to the FERC's jurisdiction. Thus far, the FERC has held conferences in Boston, Omaha, Wilmington, Tallahassee, Phoenix, New York, Dallas, Atlanta and San Francisco.

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

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

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

State Legislative Initiatives

Oklahoma

As previously reported, the Oklahoma legislature originally adopted the Electric Restructuring Act of 1997 (the "1997 Act") to provide retail customers in Oklahoma with a choice of their electric supplier. The scheduled start date for customer choice has been indefinitely postponed. In the 2003 legislative session, attempts to repeal the 1997 Act were initiated, but the session ended without repeal of the 1997 Act. It is unknown at this time whether the 1997 Act will be repealed.

In the 2004 legislative session, legislation was enacted requiring a study to determine the feasibility of providing investor-owned utilities an incentive to enter into purchase power agreements in Oklahoma by allowing the utilities to earn a return on purchased power. The study committee held its first meeting in August and continued holding two meetings a month

through November. At the conclusion of the meetings, the study committee determined that the final report would make no recommendations to the legislature in January 2005.

During the 2004 legislative session, the Oklahoma state legislature passed a bill amending the Oklahoma Gas Gathering Act (the "Gathering Act") and the Governor signed the bill into law in April 2004. Previously, Oklahoma law established a complaint procedure by which producers of natural gas could file a complaint with the OCC, asserting that a gatherer's proposed fees or terms and conditions of service were unfair or discriminatory, and request that the OCC set the fee or terms. The amendments to the Gathering Act maintained the complaint driven form of regulation by the OCC, but modified certain procedural aspects by which the complaint is handled. In particular, the amendments relate to the discovery process, and the OCC's ability to require parties and non-parties to produce documents and contracts related to the complaint at issue. However, under the amendments, processing natural gas remains unregulated. Additionally, the amendments do not allow the OCC to abrogate existing contracts between producers and gatherers.

Arkansas

In April 1999, Arkansas passed the Restructuring Law calling for restructuring of the electric utility industry at the retail level. The Restructuring Law, which had initially targeted customer choice of electricity providers by January 1, 2002, was repealed in March 2003 before it was implemented. As part of the repeal legislation, electric public utilities were permitted to recover transition costs. OG&E 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 OG&E to recover approximately $1.9 million in transition costs over an 18-month period beginning February 2004.

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

As discussed above, legislation was enacted in Oklahoma and Arkansas that was to restructure the electric utility industry in those states. The Arkansas legislation was repealed and implementation of the Oklahoma restructuring legislation has been delayed and seems unlikely to proceed during the near future. Yet, if and when implemented, this legislation could

deregulate OG&E's electric generation assets and cause OG&E to discontinue the use of SFAS No. 71 with respect to its related regulatory balances. This may result in either full recovery of generation-related regulatory assets (net of related regulatory liabilities) or a non-cash, pre-tax write-off as an extraordinary charge, depending on the transition mechanisms developed by the legislature for the recovery of all or a portion of these net regulatory assets.

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

Summary

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

19. Fair Value of Financial Instruments

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

	2004		2003	
(In millions)	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Price Risk Management Assets				
Energy Trading Contracts	**$ 130.3**	**$ 130.3**	$ 67.2	$ 67.2
Interest Rate Swaps	**7.9**	**7.9**	7.6	7.6
Price Risk Management Liabilities				
Energy Trading Contracts	**$ 109.5**	**$ 109.5**	$ 51.4	$ 51.4
Long-Term Debt and Preferred Securities				
Senior Notes	**$ 810.9**	**$ 864.1**	$ 571.8	$ 611.8
Industrial Authority Bonds	**135.4**	**135.4**	135.4	135.4
Enogex Notes	**514.1**	**556.3**	576.0	674.7
Unconsolidated Affiliate	---	---	206.2	217.8

The carrying value of the financial instruments on the Consolidated 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 swaps and energy trading contracts was determined primarily based on quoted market prices. However, in certain instances where market quotes are not available, other valuation techniques or models are used to estimate market values. The valuation of instruments also considers the credit risk of the counterparties and the potential impact of liquidating the position in an orderly manner over a reasonable period of time. The fair value of the Company's long-term debt is based on quoted market prices and management's estimate of current rates available for similar issues with similar maturities.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
OGE Energy Corp.

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

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

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

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

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 23, 2005

Supplementary Data

Interim Consolidated Financial Information (Unaudited)

In the opinion of the Company, the following quarterly information includes all adjustments, consisting of normal recurring adjustments, necessary to fairly present the Company's consolidated results of operations for such periods:

Quarter ended *(In millions, except per share data)*		Dec 31	Sep 30	Jun 30	Mar 31
Operating revenues (A)	**2004**	**$ 1,404.8**	**$ 1,324.7**	**$ 1,155.4**	**$ 1,041.7**
	2003	816.2	1,060.0	852.6	1,050.2
Operating income (A) (B) (C)	**2004**	**$ 41.7**	**$ 162.6**	**$ 82.2**	**$ 31.0**
	2003	15.3	187.3	76.6	27.7
Net income (loss) (B (C))	**2004**	**$ 9.7**	**$ 94.6**	**$ 39.0**	**$ 10.2**
	2003	(1.6)	99.5	32.2	(0.3)
Basic earnings (loss) per average common share	**2004**	**$ 0.10**	**$ 1.08**	**$ 0.44**	**$** 0.12
	2003	(0.03)	1.21	0.41	---
Diluted earnings (loss) per average common share	**2004**	**$ 0.10**	**$ 1.07**	**$ 0.44**	**$** 0.12
	2003	(0.03)	1.20	0.41	---

(A) These amounts have been restated due to Enogex's exploration and production assets, NuStar and Belvan being reported as discontinued operations during 2003.
(B) In the fourth quarter of 2003, the Company recognized a pre-tax impairment loss of approximately $9.2 million and $1.0 million in the Natural Gas Pipeline segment and Other Operations, respectively. The impairment loss in the Natural Gas Pipeline segment related to natural gas compression assets. The impairment loss in Other Operations related to the Company's aircraft.
(C) In the third quarter of 2004, the Company recognized a pre-tax impairment loss of approximately $8.6 million in the Natural Gas Pipeline segment related to four of Enogex's non-contiguous pipeline asset segments located in West Texas.

Dividends

COMMON STOCK

Common quarterly dividends paid (as declared) in 2004, 2003, and 2002 were $0.33 ¼.
Present rate – $0.33 ¼
Payable 30th of January, April, July, and October

Security Ratings*

	Moody's	Standard & Poor's	Fitch's
OG&E Senior Notes	A2	BBB+	AA-
Enogex Notes	Baa3	BBB+	BBB
OGE Energy Corp. Senior Notes	Baa1	BBB	A
OGE Energy Corp. Commercial Paper	P-2	A-2	F1

* 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 rating of the OG&E Senior Notes, Enogex Notes and OGE Energy Corp. commercial paper.

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.

Market Prices

	2004		2003	
NEW YORK STOCK EXCHANGE	**High**	**Low**	High	Low
Common				
First Quarter	**$ 26.70**	**$ 23.03**	$ 19.37	$ 15.99

Second Quarter	**26.80**	**22.85**	22.25	17.36
Third Quarter	**26.48**	**24.10**	22.75	19.50
Fourth Quarter	**26.95**	**25.17**	24.34	21.96

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

None.

Item 9A. Controls and Procedures.

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

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

Management's Report on Internal Control Over Financial Reporting

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

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

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

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
OGE Energy Corp.

We have audited management's assessment, included in the accompanying Management's Report on Internal Control Over Financial Reporting, that OGE Energy Corp. maintained effective internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). OGE Energy Corp.'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 OGE Energy Corp. maintained effective internal control over financial reporting as of December 31, 2004, is fairly stated, in all material respects, based on the COSO criteria. Also, in our opinion, OGE Energy Corp. maintained, in all

material respects, effective internal control over financial reporting as of December 31, 2004, based on the COSO criteria.

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

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 23, 2005

Item 9B. Other Information.

None.

PART III

Item 10. Directors and Executive Officers of the Registrant.

CODE OF ETHICS POLICY

The Company maintains a code of ethics for our chief executive officer and senior financial officers, including the chief financial officer and chief accounting officer, which is available for public viewing on the Company's web site address *www.oge.com* under the heading "Investors", "Corporate Governance." The code of ethics will be provided, free of charge, upon request. The Company intends to satisfy the disclosure requirements under Section 5, Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of the code of ethics by posting such information on its web site at the location specified above.

Item 11. Executive Compensation.

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

Approve Payout of 2004 Annual Incentive Awards

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

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

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

For Mr. Steven E. Moore, Chairman and Chief Executive Officer, Mr. A.M. Strecker, former Executive Vice President and Chief Operating Officer, and Mr. Peter B. Delaney, Executive Vice President and Chief Operating Officer, the three most senior executive officers of the Company at the time the corporate goals were established, the corporate goals were based: (i) 50% on a Company consolidated earnings per share target established by the Committee

(the "2004 Earnings Target"), (ii) 25% on a combined operating and maintenance expense and capital expenditure target for the Company and OG&E established by the Committee (the "2004 O&M/Capital Target"), and (iii) 25% on consolidated net income of Enogex and its subsidiaries (the "2004 Unregulated Income

Target”). These three corporate goals were also used in establishing the corporate goals for all other executive officers. However, the weighting of the goals was slightly different for the remaining executive officers, with the corporate goals for one executive officer being based 50% on the 2004 Earnings Target and 50% on the 2004 O&M/Capital Target while for the remaining executive officers the corporate goals were based 50% on the 2004 Earnings Target, with the remaining 50% allocated between the 2004 O&M/Capital Target and the 2004 Unregulated Income Target based on the responsibilities of the individual’s position.

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

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

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

2005 Compensation for Executive Officers

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

Salary

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

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

Annual Incentive Awards

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

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

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

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

Long-Term Awards

For 2005, the Committee made awards of performance units. The number of performance units granted was determined by taking the amount of the executive’s long-term award to be delivered in performance units (adjusted on a present value basis), as determined by

the Committee, and dividing that amount by the closing price for the Company’s Common Stock on January 3, 2005 with a vesting factor applied. This resulted in executives receiving performance units with an expected value at the date of grant of from 25% to 150% of their 2005 base salaries. The value of the performance units is substantially dependent upon the changing value of the Company’s Common Stock in the marketplace. Each executive officer is entitled to receive from 0% to 200% of the performance units contingently awarded to the executive depending upon corporate performance. For 75% of the performance units, this corporate performance will be based on the Company's total shareholder return over a three-year period (defined as share price increase plus dividends paid, divided by share price at beginning of the period) measured against the total shareholder return for such period by a peer group selected by the Committee. For the remaining 25% of the performance units, the corporate performance will be based upon the growth in the Company's earnings per share compared to specified targets selected by the Committee.

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

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

Director Compensation

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

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

Equity Compensation Plan Information

The following table provides certain information as of December 31, 2004 with respect to the shares of the Company's Common Stock that may be issued under the existing equity compensation plans:

	A	B	C
Plan Category	Number of Securities to be Issued upon Exercise of Outstanding Options	Weighted Average Price of Outstanding Options	Number of Securities Remaining Available for future issuances under equity compensation plans (excluding securities reflected in Column A)
Equity Compensation Plans Approved by Shareowners (A)	2,827,914	$22.16	2,209,763 (B)
Equity Compensation Plans Not Approved by Shareowners	0	N/A	N/A

(A) Consists of the OGE Energy Corp. Stock Incentive Plan, which was approved by shareowners at the 1998 annual meeting and OGE Energy Corp. 2003 Stock Incentive Plan, which was approved by shareowners at the 2003 annual meeting.

(B) Awards under the Stock Incentive Plan can take the form of stock options, stock appreciation rights, restricted stock or performance units.

N/A – not applicable

Item 13. Certain Relationships and Related Transactions.

Item 14. Principal Accounting Fees and Services.

Items 10, 11, 12, 13 and 14 (other than Item 10 information regarding the Code of Ethics, Item 11 information relating to recent executive officer and director compensation matters and Item 12 information required by Item 201(d) of Regulation S-K) are omitted pursuant to General Instruction G of Form 10-K, since the Company will file copies of a definitive proxy statement with the Securities and Exchange Commission on or about March 31, 2005. Such proxy statement is incorporated herein by reference. In accordance with General Instruction G of Form 10-K, the information required by Item 10 relating to Executive Officers has been included in Part I, Item 4, of this Form 10-K.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

(a) 1. Financial Statements

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

- Consolidated Balance Sheets at December 31, 2004 and 2003
- Consolidated Statements of Capitalization at December 31, 2004 and 2003
- Consolidated Statements of Income for the years ended December 31, 2004, 2003 and 2002
- Consolidated Statements of Retained Earnings for the years ended December 31, 2004, 2003 and 2002
- Consolidated Statements of Comprehensive Income for the years ended December 31, 2004, 2003 and 2002
- Consolidated Statements of Cash Flows for the years ended December 31, 2004, 2003 and 2002
- Notes to Consolidated 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 Consolidated Financial Information

2. Financial Statement Schedule (included in Part IV)	**Page**
Schedule II - Valuation and Qualifying Accounts	185

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 consolidated financial statements or notes thereto.

3. Exhibits

Exhibit No.	**Description**
2.01	Purchase Agreement, dated as of May 14, 1999, by and between Tejas Gas, LLC and Enogex Inc. (Filed as Exhibit 2.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 1999 (File No. 1-12579) and incorporated by reference herein)
2.02	Asset Purchase Agreement, dated as of August 18, 2003 by and between OG&E 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 OGE Energy's Form 8-K dated August 18, 2003 (File No. 1-12579) and incorporated by reference herein)
2.03	Amendment No. 1 to Asset Purchase Agreement, dated as of October 22, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.03 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No.1-12579) and incorporated by reference herein)
2.04	Amendment No. 2 to Asset Purchase Agreement, dated as of October 27, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.04 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.05	Amendment No. 3 to Asset Purchase Agreement, dated as of November 25, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.05 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.06	Amendment No. 4 to Asset Purchase Agreement, dated as of January 28, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.06 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.07	Amendment No. 5 to Asset Purchase Agreement, dated as of February 13, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.07 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)

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

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

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

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

2.12 Amendment No. 10 to Asset Purchase Agreement, dated as of June 17, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.03 to OGE Energy'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 3.01 to OGE Energy's Form 10-K for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)

3.02 Copy of Amended By-laws.

4.01 Trust Inde nture dated October 1, 1995, from OG&E 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 OG&E's Form 8-K dated October 23, 1995 (File No. 1-1097) and incorporated by reference herein)

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

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

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

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

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

4.08 Indenture dated as of November 1, 2004 between OGE Energy Corp. and UMB Bank, N.A., as trustee. (Filed as Exhibit 4.01 to OGE Energy's Form 8-K filed on November 12, 2004 (File No. 1-12579) and incorporated by reference herein)

4.09 Supplemental Indenture No. 1 dated as of November 9, 2004 between OGE Energy Corp. and UMB Bank, N.A., as trustee. (Filed as Exhibit 4.02 to OGE Energy's Form 8-K filed on November 12, 2004 (File No. 1-12579) and incorporated by reference herein)

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

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

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

10.04 OGE Energy Corp. Restoration of Retirement Income Plan, as amended by Amendments No. 1 and No. 2. (Filed as Exhibit 10.12 to OGE Energy'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 OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.13 to OGE Energy'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 OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.14 to OGE Energy's Form 10-K for the year ended December 31, 2000 (File No. 1-12579) and incorporated by reference herein)

10.07 OGE Energy Corp. Supplemental Executive Retirement Plan, as amended by Amendment No. 1.

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

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

10.10 Copy of Amended and Restated Rights Agreement, dated as of October 10, 2000 between OGE Energy Corp. and Chase Mellon Shareholder Services, LLC, as Rights Agent. (Filed as Exhibit 4.1 to OGE Energy's Form 8-K filed on November 1, 2000 (File No. 1-12579) and incorporated by reference herein)

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

10.12 Copy of Employment Agreement with Peter B. Delaney. (Filed as Exhibit 10.15 to OGE Energy's Form 10-K for the year ended December 31, 2002 (File No. 1-12579) and incorporated by reference herein)

10.13 Copy of Severance Agreement with Roger A. Farrell. (Filed as Exhibit 10.16 to OGE Energy's Form 10-K for the year ended December 31, 2002 (File No. 1-12579) and incorporated by reference herein)

10.14 Revolving Note Agreement as amended by Amendments No. 1 and No. 2, dated April 6, 2002 between OGE Energy Corp. and Bank of Oklahoma, N.A. (Filed as Exhibit 10.19 to OGE Energy's Form 10-K for the year ended December 31, 2002 (File No. 1-12579) and incorporated by reference herein)

10.15 Revolving Note Agreement as amended by Amendment No. 3, dated April 6, 2003 between OGE Energy Corp. and Bank of Oklahoma, N.A. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12579) and incorporated by reference herein)

10.16 Fourth Amendment to Loan Agreement, dated April 6, 2004 between OGE Energy Corp. and Bank of Oklahoma, N.A. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein)

10.17 Consulting Agreement, dated as of June 30, 2004 by and between OGE Energy Corp. and Al Strecker. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)

10.18 Amended and Restated Facility Operating Agreement for the McClain Generating Facility dated as of July 9, 2004 between OG&E and the Oklahoma Municipal Power Authority. (Filed as

Exhibit 10.03 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)

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

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

10.21 Credit agreement dated October 20, 2004, by and between the Company, Wachovia Bank, National Association, JPMorgan Chase Bank, Citibank, N.A., The Royal Bank of Scotland plc and Union Bank of California, N.A. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K dated October 25, 2004 (File No. 1-12579) and incorporated by reference herein)

10.22 Credit agreement dated October 20, 2004, by and between OG&E, 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 OGE Energy's Form 8-K dated October 25, 2004 (File No. 1-12579) and incorporated by reference herein)

10.23 Amendment No. 1 to Company's 2003 Stock Incentive Plan.

10.24 Intrastate Firm No-Notice, Load Following Transportation and Storage Services Agreement dated as of May 1, 2003 between OG&E and Enogex. [Confidential Treatment has been requested for certain portions of this exhibit.]

10.25 Firm Transportation Service Agreement Rate Schedule FT dated as of December 1, 2004 between OGE Energy Resources, Inc. and Cheyenne Plains Gas Pipeline Company, L.L.C.

10.26 Amendment No. 5 to the OGE Energy Corp. Restoration of Retirement Income Plan.

10.27 Directors' Compensation.

10.28 Executive Officer Compensation.

10.29 Form of Non--Qualified Stock Option Agreement under 2003 Stock Incentive Plan.

10.30 Form of Performance Unit Agreement under 2003 Stock Incentive Plan.

10.31 Form of Restricted Stock Agreement under 2003 Stock Incentive Plan.

10.32 Form of Split Dollar Agreement.

12.01 Calculation of Ratio of Earnings to Fixed Charges.

21.01 Subsidiaries of the Registrant.

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.

Executive Compensation Plans and Arrangements

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

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

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

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

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10.32 Form of Split Dollar Agreement.

OGE ENERGY CORP.

SCHEDULE II — Valuation and Qualifying Accounts

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

	(In millions)									
Year Ended December 31, 2002										
Reserve for Uncollectible Accounts	$	9.7	$	11.0	$	3.7	$	10.8 (A)	$	13.6
Year Ended December 31, 2003										
Reserve for Uncollectible Accounts	$	13.6	$	2.0	$	---	$	11.4 (A)	$	4.2
Year Ended December 31, 2004										
Reserve for Uncollectible Accounts	$	4.2	$	5.8	$	---	$	5.5 (A)	$	4.5

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

SIGNATURES

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

OGE ENERGY CORP.
(Registrant)

By /s/ Steven E. Moore

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

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

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

Exhibit Index

Exhibit No.	**Description**
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2.05	Amendment No. 3 to Asset Purchase Agreement, dated as of November 25, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.05 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.06	Amendment No. 4 to Asset Purchase Agreement, dated as of January 28, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.06 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.07	Amendment No. 5 to Asset Purchase Agreement, dated as of February 13, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.07 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.08	Amendment No. 6 to Asset Purchase Agreement, dated as of March 12, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.01 to OGE Energy's Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein)
2.09	Amendment No. 7 to Asset Purchase Agreement, dated as of April 15, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.02 to OGE Energy's

	Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein)
2.10	Amendment No. 8 to Asset Purchase Agreement, dated as of May 15, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
2.11	Amendment No. 9 to Asset Purchase Agreement, dated as of June 2, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.02 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
2.12	Amendment No. 10 to Asset Purchase Agreement, dated as of June 17, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.03 to OGE Energy'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 3.01 to OGE Energy's Form 10-K for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)
3.02	Copy of Amended By-laws.
4.01	Trust Inde nture dated October 1, 1995, from OG&E 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 OG&E's Form 8-K dated October 23, 1995 (File No. 1-1097) and incorporated by reference herein)

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

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

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

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

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

4.08 Indenture dated as of November 1, 2004 between OGE Energy Corp. and UMB Bank, N.A., as trustee. (Filed as Exhibit 4.01 to OGE Energy's Form 8-K filed on November 12, 2004 (File No. 1-12579) and incorporated by reference herein)

4.09 Supplemental Indenture No. 1 dated as of November 9, 2004 between OGE Energy Corp. and UMB Bank, N.A., as trustee. (Filed as Exhibit 4.02 to OGE Energy's Form 8-K filed on November 12, 2004 (File No. 1-12579) and incorporated by reference herein)

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

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

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

10.04 OGE Energy Corp. Restoration of Retirement Income Plan, as amended by Amendments No. 1 and No. 2. (Filed as Exhibit 10.12 to OGE Energy'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 OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.13 to OGE Energy'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 OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.14 to OGE Energy's Form 10-K for the year ended December 31, 2000 (File No. 1-12579) and incorporated by reference herein)

10.07 OGE Energy Corp. Supplemental Executive Retirement Plan, as amended by Amendment No. 1.

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

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

10.10 Copy of Amended and Restated Rights Agreement, dated as of October 10, 2000 between OGE Energy Corp. and Chase Mellon Shareholder Services, LLC, as Rights Agent. (Filed as

Exhibit 4.1 to OGE Energy's Form 8-K filed on November 1, 2000 (File No. 1-12579) and incorporated by reference herein)

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

10.12 Copy of Employment Agreement with Peter B. Delaney. (Filed as Exhibit 10.15 to OGE Energy's Form 10-K for the year ended December 31, 2002 (File No. 1-12579) and incorporated by reference herein)

10.13 Copy of Severance Agreement with Roger A. Farrell. (Filed as Exhibit 10.16 to OGE Energy's Form 10-K for the year ended December 31, 2002 (File No. 1-12579) and incorporated by reference herein)

10.14 Revolving Note Agreement as amended by Amendments No. 1 and No. 2, dated April 6, 2002 between OGE Energy Corp. and Bank of Oklahoma, N.A. (Filed as Exhibit 10.19 to OGE Energy's Form 10-K for the year ended December 31, 2002 (File No. 1-12579) and incorporated by reference herein)

10.15 Revolving Note Agreement as amended by Amendment No. 3, dated April 6, 2003 between OGE Energy Corp. and Bank of Oklahoma, N.A. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended March 31, 2003 (File No. 1-12579) and incorporated by reference herein)

10.16 Fourth Amendment to Loan Agreement, dated April 6, 2004 between OGE Energy Corp. and Bank of Oklahoma, N.A. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein)

10.17 Consulting Agreement, dated as of June 30, 2004 by and between OGE Energy Corp. and Al Strecker. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)

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

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

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

10.21 Credit agreement dated October 20, 2004, by and between the Company, Wachovia Bank, National Association, JPMorgan Chase Bank, Citibank, N.A., The Royal Bank of Scotland plc and Union Bank of California, N.A. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K dated October 25, 2004 (File No. 1-12579) and incorporated by reference herein)

10.22 Credit agreement dated October 20, 2004, by and between OG&E, 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 OGE Energy's Form 8-K dated October 25, 2004 (File No. 1-12579) and incorporated by reference herein)

10.23 Amendment No. 1 to Company's 2003 Stock Incentive Plan.

10.24 Intrastate Firm No-Notice, Load Following Transportation and Storage Services Agreement dated as of May 1, 2003 between OG&E and Enogex. [Confidential Treatment has been requested for certain portions of this exhibit.]

10.25 Firm Transportation Service Agreement Rate Schedule FT dated as of December 1, 2004 between OGE Energy Resources, Inc. and Cheyenne Plains Pipeline Company, L.L.C.

10.26 Amendment No. 5 to the OGE Energy Corp. Restoration of Retirement Income Plan.

10.27 Directors' Compensation.

10.28 Executive Officer Compensation.

10.29 Form of Non - -Qualified Stock Option Agreement under 2003 Stock Incentive Plan.

10.30 Form of Performance Unit Agreement under 2003 Stock Incentive Plan.

10.31 Form of Restricted Stock Agreement under 2003 Stock Incentive Plan.

10.32 Form of Split Dollar Agreement.

12.01 Calculation of Ratio of Earnings to Fixed Charges.

21.01 Subsidiaries of the Registrant.

23.01 Consent of Ernst & Young LLP.

24.01 Power of Attorney.

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

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

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

Exhibit 3.02

BY-LAWS
of
OGE ENERGY CORP.

(Effective as of January 19, 2005)

ARTICLE 1.
AMENDMENTS

Section 1.1. Amendment of By-Laws. Subject to the provisions of the Corporation’s Restated Certificate of Incorporation, these By-laws may be amended or repealed at any regular meeting of the shareholders (or at any special meeting thereof duly called for that purpose) by the holders of at least a majority of the voting power of the shares represented and entitled to vote thereon at such meeting at which a quorum is present; provided that in the notice of such special meeting notice of such purpose shall be given. Subject to the laws of the State of Oklahoma, the Corporation’s Restated Certificate of Incorporation and these By-laws, the Board of Directors may by majority vote of those present at any meeting at which a quorum is present amend these By-laws, or adopt such other Bylaws as in their judgment may be advisable for the regulation of the conduct of the affairs of the Corporation.

ARTICLE 2.
OFFICES

Section 2.1. Registered Office. The Corporation shall continuously maintain a registered office in the State of Oklahoma which may, but need not be, the same as its place of business, and a registered agent whose business office is identical with such registered office.

Section 2.2. Other Offices. The Corporation may also have offices at such other places both within and without the State of Oklahoma as the Board of Directors may from time to time determine or the business of the corporation may require.

ARTICLE 3.
SHARES

Section 3.1. Form of Shares. Shares either shall be represented by certificates or shall be uncertificated shares.

3.1.1. Signing of Certificates. Certificates representing shares of the corporation shall be signed by the appropriate officers and may be sealed with the seal or a facsimile of the seal of the Corporation if the corporation uses a seal. If a certificate is countersigned by a transfer agent or registrar, other than an employee of the corporation, any other signatures may be facsimile. Each certificate representing shares shall be consecutively numbered or otherwise identified, and shall also state the name of the person to whom issued, the number and class of shares (with designation of series, if any), the date of issue, that the corporation is organized under Oklahoma

law, and any other information required by law.

3.1.2. Uncertificated Shares. Unless prohibited by the Restated Certificate of Incorporation, the Board of Directors may provide by resolution that some or all of any class or series of shares shall be uncertificated shares. Any such resolution shall not apply to shares represented by a certificate until the certificate (or such documentation as may be allowed under Section 3.2 below) has been surrendered to the Corporation. Within a reasonable time after the issuance or transfer of uncertificated shares, the Corporation shall send the registered owner thereof a written notice of all information that would appear on a certificate. Except as otherwise expressly provided by law, the rights and obligations of the holders

of uncertificated shares shall be identical to those of the holders of certificates representing shares of the same class and series.

3.1.3. Identification of Shareholders. The name and address of each shareholder, the number and class of shares held and the date on which the shares were issued shall be entered on the books of the Corporation. The person in whose name shares stand on the books of the Corporation shall be deemed the owner thereof for all purposes as regards the Corporation.

Section 3.2. Lost. Stolen or Destroyed Certificates. If a certificate representing shares has allegedly been lost, stolen or destroyed, the Board of Directors may in its discretion, except as may be required by law, direct that a new certificate be issued upon such identification and other reasonable requirements as it may impose.

Section 3.3. Transfers of Shares. Transfer of shares of the Corporation shall be recorded on the books of the Corporation. Transfer of shares represented by a certificate, except in the case of a lost or destroyed certificate, shall be made on surrender for cancellation of the certificate for such shares. A certificate presented for transfer must be duly endorsed and accompanied by proper guaranty of signature or other appropriate assurances that the endorsement is effective. Transfer of an uncertificated share shall be made on receipt by the Corporation of an instruction from the registered owner or other appropriate person. The instruction shall be in writing or a communication in such form as may be agreed upon in writing by the Corporation.

ARTICLE 4.
SHAREHOLDERS

Section 4.1. Annual Meeting. The annual meeting of the shareholders for the election of directors and the transaction of any other proper business shall be held at a time and date to be annually designated by the Board of Directors.

Section 4.2. Special Meetings. Except as otherwise mandated by Oklahoma law and except as may otherwise be provided in or fixed by or pursuant to the provisions of Article IV of the Corporation’s Restated Certificate of Incorporation relating to the rights of the holders of any class or series of stock having a preference over the Common Stock as to dividends or upon liquidation to elect directors under specified circumstances, special meetings of shareholders of the Corporation may be called only by the Board of Directors pursuant to a resolution approved by a majority of the entire Board of Directors or by the President of the Corporation.

Section 4.3. Place of Meeting. The Board of Directors may designate the place of meeting for any annual or special meeting of shareholders. In the absence of any such designation, the place of meeting shall be the principal place of business of the Corporation.

Section 4.4. Notice of Meetings. For all meetings of shareholders, a written or printed notice of the meeting shall be delivered, personally or by mail, to each shareholder of record entitled to vote at such meeting, which notice shall state the place, date and hour of the meeting. For all special meetings and when and as otherwise required by law, the notice shall state the purpose or purposes of the meeting. The notice of the meeting shall be given not less than 10 nor more than 60 days before the date of the meeting, or in the case of a meeting involving a merger, consolidation, share exchange, dissolution or sale, lease or an exchange of all or substantially all, of the property or assets of the corporation not less than 20 nor more than 60 days before the date of such meeting. If mailed, such notice shall be deemed to have been delivered when deposited in the United States mail, postage prepaid, directed to the shareholder at his or her address as it appears on the records of the corporation. When a meeting is adjourned to another time or place, notice need not be given of the adjourned meeting if the time and place thereof are announced at the meeting at which the adjournment is taken unless otherwise required by law.

Section 4.5. Quorum of Shareholders. The holders of a majority of the outstanding shares of the corporation entitled to vote on a matter, present in person or represented by proxy, shall constitute a quorum for consideration of such matters at any meeting of shareholders unless a greater or lesser number is required by the certificate of incorporation. At any adjourned meeting at which a quorum is present or represented, any business may be transacted which might have been transacted at the original meeting, unless otherwise required by law. Withdrawal of shareholders from any meeting shall not cause failure of a duly constituted quorum at the meeting, unless otherwise required by law.

Section 4.6. Manner of Acting. The affirmative vote of holders of a majority of the shares represented at a meeting and entitled to vote on a matter at which a quorum is present shall be valid action by the shareholders, unless voting by a greater number of shareholders or voting by class or classes of shareholders is required by law or the certificate of incorporation.

Section 4.7. Fixing of Record Date. If no record date is fixed for the determination of shareholders entitled to notice of or to vote at a meeting of shareholders, or shareholders entitled to receive payment of a dividend, or in order to make a determination of shareholders for any other proper purpose, the date on which notice of the meeting is mailed or the date on which the resolution of the Board of Directors declaring such dividend is adopted, as the case may be, shall be the record date for such determination of shareholders. If a record date is specifically set for the purpose of determining shareholders entitled to notice of or to vote at any meeting of shareholders, or shareholders entitled to receive payment of any dividend, or in order to make a determination of shareholders for any other proper purpose, the Board of Directors may fix in advance a date as the record date for any such determination of shareholders, such date in any case to be not more than 60 days (or such longer period as is then permitted by Oklahoma law) and, for a meeting of shareholders, not less than 10 days, or in the case of a merger, consolidation, share exchange, dissolution or sale, lease or exchange of assets, not less than 20 days, immediately preceding such meeting. When a determination of shareholders entitled to

vote at any meeting of shareholders has been made as provided in this Section, such determination shall apply to any adjournment thereof.

Section 4.8. Voting Lists. The officer or agent having charge of the transfer book for shares of the Corporation shall make, within 20 days after the record date for a meeting of shareholders or 10 days before such meeting, whichever is earlier, a complete list of the shareholders entitled to vote at such meeting, arranged in alphabetical order, with the address of and the number of shares held by each, which list, for a period of 10 days prior to such meeting, shall be kept on file at the registered office of the corporation and shall be subject to inspection by any shareholders, and to copying at the shareholder's expense, at any time during usual business hours. Such list shall also be produced and kept open at the time and place of the meeting and shall be subject to the inspection of any shareholder during the whole time of the meeting. The original share ledger or transfer book, or a duplicate thereof kept in the State of Oklahoma, shall be prima facie evidence as to who are the shareholders entitled to examine such list or share ledger or transfer book or to vote at any meeting of shareholders.

Section 4.9. Proxies. A shareholder may appoint a proxy to vote or otherwise act for him or her by signing an appointment form and delivering it to the person so appointed. All appointments of proxies shall be in accordance with Oklahoma law. An appointment of a proxy is revocable by the shareholder unless the appointment form conspicuously states that it is irrevocable and the appointment is coupled with an interest in the shares or in the corporation generally.

Section 4.10. Voting of Shares by Certain Holders. Shares of a corporation held by the Corporation in a fiduciary capacity may be voted and shall be counted in determining the total number of outstanding shares entitled to vote at any given time.

4.10.1. Shares Held by Corporation. Shares registered in the name of another corporation, domestic or foreign, may be voted by any officer, agent, proxy or other legal representative authorized to vote such shares under the laws of the state of incorporation of such corporation. This Corporation shall treat the president or other person holding the chief executive office of such other corporation as authorized to vote such shares. However, such other corporation may designate any other person or any other holder of an office of the corporate shareholder to this corporation as the person or officeholder authorized to vote such shares. Such persons or offices indicated shall be registered by this Corporation on the transfer books for shares and included in any voting list prepared in accordance with Section 4.8 of this Article.

4.10.2. Shares Held by Fiduciary. Shares registered in the name of a deceased person, a minor ward or a person under legal disability may be voted by his or her administrator, executor, or court appointed guardian, either in person or by proxy, without a transfer of such shares into the name of such administrator, executor, or court appointed guardian. Shares registered in the name of a trustee may be voted by him or her, either in person or by proxy.

4.10.3. Shares Held by Receiver. Shares registered in the name of a receiver may be voted by such receiver, and shares held by or under the control of a receiver may be voted by such receiver without the transfer thereof into his or her name if authority to do so is contained in an

appropriate order of the court by which such receiver was appointed.

4.10.4. Shares Pledged. A shareholder whose shares are pledged shall be entitled to vote such shares until the shares have been transferred into the name of the pledgee, and thereafter the pledgee shall be entitled to vote the shares so transferred.

Section 4.11. Inspectors. At any meeting of shareholders, the chairman of the meeting may, or upon the request of any shareholder shall, appoint one or more persons as inspectors for such meeting. Inspectors shall:

4.11.1. Vote Count and Report. Determine the validity and effect of proxies; ascertain and report the number of shares represented at the meeting; count all votes and report the results; and perform such other acts as are required and appropriate to conduct all elections with impartiality and fairness to the shareholders.

4.11.2. Written Reports. Each report shall be in writing and such report shall be signed by the inspector or by a majority of them if there be more than one inspector acting at such meeting. If there is more than one inspector, the report of a majority shall be the report of the inspectors. The report of the inspector or inspectors on the number of shares represented at the meeting and the results of the voting shall be prima facie evidence thereof.

Section 4.12. Informal Action by Shareholders. Any action required or permitted to be taken by the shareholders of the Corporation must be effected at a duly called annual or special meeting of such holders and, except as otherwise mandated by Oklahoma law, may not be effected without such a meeting by any consent in writing by such holders.

Section 4.13. Waiver of Notice. Whenever any notice whatever is required to be given under the provisions of the law, the certificate of incorporation or these By-laws, a waiver thereof in writing signed by the person or persons entitled to such notice, whether before or after the time stated therein, shall be deemed equivalent to the giving of such notice. Attendance at any meeting shall constitute waiver of notice thereof unless the person at the meeting objects to the holding of the meeting because proper notice was not given.

Section 4.14. Notice of Shareholder Business. At an annual meeting of the shareholders, only such business shall be conducted as shall have been properly brought before the meeting. To be properly brought before an annual meeting, business must be (a) specified in the notice of meeting (or any supplement thereto) given by or at the direction of the Board of Directors, (b) otherwise properly brought before the meeting by or at the direction of the Board of Directors, or (c) otherwise properly be requested to be brought before the meeting by a shareholder. For business to be properly requested to be brought before an annual meeting by a shareholder, the shareholder must have given timely notice thereof in writing to the Secretary of the Corporation. To be timely, a shareholder's notice must be delivered to or mailed and received at the principal executive offices of the Corporation, not less than 90 days prior to the meeting; provided, however, that in the event that the date of the meeting is not publicly announced by the Corporation by mail, press release or otherwise more than 90 days prior to the meeting, notice by the shareholder to be timely must be delivered to the Secretary of the Corporation not later than

the close of business on the seventh day following the day on which such announcement of the date of the meeting was communicated to shareholders. A shareholder's notice to the Secretary shall set forth as to each matter the shareholder proposes to bring before the annual meeting (a) a brief description of the business desired to be brought before the annual meeting and the reasons for conducting such business at the annual meeting, (b) the name and address, as they appear on the Corporation's books, of the shareholder proposing such business, (c) the class and number of shares of the Corporation which are beneficially owned by the shareholder, and (d) any material interest of the shareholder in such business. Notwithstanding anything in the By-laws to the contrary, no business shall be conducted at an annual meeting except in accordance with the procedures set forth in this Section 4.14. The Chairman of an annual meeting shall, if the facts warrant, determine and declare to the meeting that business was not properly brought before the meeting and in accordance with the provisions of this Section 4.14, and if he should so determine, he shall so declare to the meeting that any such business not properly brought before the meeting shall not be transacted.

ARTICLE 5.
DIRECTORS

Section 5.1. General Powers and Qualification. The business and affairs of the Corporation shall be managed by or under the direction of the Board of Directors. Directors need not be residents of the State of Oklahoma or shareholders of the Corporation.

Section 5.2. Number. Tenure and Resignation. The number of directors of the Corporation shall be fixed from time to time by the Board of Directors, but shall be no fewer than 9 and no more than 15; provided, however, that no decrease in the number of directors shall have the effect of shortening the term of any incumbent director. Except as may otherwise be provided in or fixed by or pursuant to the provisions of Article IV of the Corporation's Restated Certificate of Incorporation relating to the rights of the holders of any class or series of stock having a preference over the Corporation's Common Stock as to dividends or upon liquidation to elect directors under specified circumstances, the directors shall be classified, with respect to the time for which they severally hold office, into three classes, as nearly equal in number as possible, as determined by the Board of Directors, one class to be originally elected for a term expiring at the annual meeting of shareholders to be held in 1996, another class to be originally elected for a term expiring at the annual meeting of shareholders to be held in 1997, and another class to be originally elected for a term expiring at the annual meeting of shareholders to be held in 1998, with each class to hold office until its successor is elected and qualified. At each annual meeting of the shareholders and except as may otherwise be provided in or fixed by or pursuant to the provisions of Article IV of the Corporation's Restated Certificate of Incorporation relating to the rights of the holders of any class or series of stock having a preference over the Corporation's Common Stock as to dividends or upon liquidation to elected directors under specified circumstances, the successors of the class of directors whose term expires at that meeting shall be elected to hold office for a term expiring at the annual meeting of shareholders held in the third year following the year of their election.

Advance notice of shareholder nominations for the election of directors shall be given in the manner provided in Section 5.3 of this Article 5.

Except as may otherwise be provided in or fixed by or pursuant to the provisions of Article IV of the Corporation's Restated Certificate of Incorporation relating to the rights of the holders of any class or series of stock having a preference over the Corporation's Common Stock as to dividends or upon liquidation to elect directors under specified circumstances: (i) newly created directorships resulting from any increase in the number of directors and any vacancies on the Board of Directors resulting from death, resignation, disqualification, removal or other cause shall be filled by the affirmative vote of a majority of the remaining directors then in office, even though less than quorum of the Board of Directors, (ii) any director elected in accordance with the preceding clause (i) shall hold office for the remainder of the full term of the class of directors in which the new directorship was created or the vacancy occurred and until such director's successor shall have been elected and qualified and (iii) no decrease in the number of directors constituting the Board of Directors shall shorten the term of any incumbent director.

Except as may otherwise be provided in or fixed by or pursuant to the provisions of Article IV of the Corporation's Restated Certificate of Incorporation relating to the rights of the holders of any class or series of stock having a preference over the Corporation's Common Stock as to dividends or upon liquidation to elect directors under specified circumstances, any director may be removed from office, with or without cause, only by the affirmative vote of the holders of at least 80% of the combined voting power of the then outstanding shares of the Corporation's stock entitled to vote generally (as defined in Article VII of the Corporation's Restated Certificate of Incorporation), voting together as a single class.

Section 5.3. Notification of Nominations. Except as may otherwise be provided in or fixed by or pursuant to the provisions of Article IV of the Corporation's Restated Certificate of Incorporation relating to the rights of the holders of any class or series of stock having a preference over the Corporation's Common Stock as to dividends or upon liquidation to elect directors under specified circumstances, nominations for the election of directors may be made by the Board of Directors or a committee appointed by the Board of Directors or by any shareholder entitled to vote in the election of directors generally. However, any shareholder entitled to vote in the election of directors generally may nominate one or more persons for election as directors at a meeting only if written notice of such shareholder's intent to make such nomination or nominations has been given, either by personal delivery or by United States mail, postage prepaid, to the Secretary of the Corporation not later than (i) with respect to an election to be held at an annual meeting of shareholders, 90 days in advance of such meeting, and (ii) with respect to an election to be held at a special meeting of stockholders for the election of directors, the close of business on the seventh day following the date on which notice of such meeting is first given to shareholders. Each such notice shall set forth (a) the name and address of the shareholder who intends to make the nomination and of the person or persons to be nominated; (b) a representation that the shareholder is a holder of record of stock of the Company entitled to vote at such meeting and intends to appear in person or by proxy at the meeting to nominate the person or persons specified in the notice; (c) a description of all arrangements or understandings between the shareholder and each nominee and any other person or persons (naming such person or persons) pursuant to which the nomination or nominations are to be made by the shareholder; (d) such other information regarding each nominee proposed by such shareholder as would be required to be included in a proxy statement filed pursuant to the

proxy rules of the Securities and Exchange Commission, had the nominee been nominated, or intended to be nominated, by the Board of Directors; and (e) the consent of each nominee to serve as a director of the Corporation if so elected. The Chairman of the meeting may refuse to acknowledge the nomination of any person not made in compliance with the foregoing procedure. A director may resign at any time by written notice to the board, its chairman, or the president or secretary of the Corporation. The resignation is effective on the date it bears, or its designated effective date.

Section 5.4. Quorum of Directors. A majority of the number of directors fixed in Section 5.2 of this Article shall constitute a quorum for the transaction of business at any meeting of the Board of Directors; provided, however, that if less than a majority of the number of directors fixed in Section 5.2 of this Article is present at a meeting, a majority of the directors present may adjourn the meeting at any time without further notice, unless otherwise required by law.

Section 5.5. Manner of Acting. The act of a majority of the directors present at a meeting at which a quorum is present shall be the act of the Board of Directors, unless the act of a greater number is required by law or these By-laws.

Section 5.6. Regular Meetings. Regular meetings of the Board of Directors may be held without notice at such time and place as shall from time to time be determined by the Board of Directors.

Section 5.7. Special Meetings. Special meetings of the Board of Directors may be called by or at the request of the president or any two directors. The person or persons authorized to call special meetings of the Board of Directors may fix the place for holding any special meeting of the Board of Directors called by them.

Section 5.8. Notice. Notice of any special meeting of the Board of Directors shall be given at least one day prior to the meeting by written notice delivered personally, by mail, cable, facsimile, telegram, or telex to each director at his or her business address. Neither the business to be transacted at, nor the purpose of, any regular or special meeting of the Board of Directors need be specified in the notice or waiver of notice of such meeting. The attendance of a director at any meeting shall constitute a waiver of notice of such meeting, except where a director attends a meeting for the express purpose of objecting to the transaction of any business because the meeting is not lawfully called or convened.

Section 5.9. Presumption of Assent. A director of the Corporation who has been present at a meeting of the Board of Directors at which action on any corporate matter is taken shall be conclusively presumed to have assented to the action taken, unless his or her dissent shall have been entered in the minutes of the meeting or unless he or she shall have filed his or her written dissent to such action with the person acting as the secretary of the meeting before the adjournment thereof, or shall have forwarded such dissent by registered mail or certified mail to the secretary of the Corporation immediately after the adjournment of the meeting. No director who voted in favor of any action may dissent from such action after adjournment of the meeting.

Section 5.10. Committees. A majority of the directors may, by resolution passed by a majority of the number of directors fixed by the shareholders under Section 5.2 of this Article, create one or more committees and appoint members of the board to serve on the committee or committees. Each committee shall have two or more members, who serve at the pleasure of the board. To the extent specified in the resolution of the Board of Directors establishing a committee each committee shall have and exercise all the authority of the Board of Directors, provided, however, that no such committee shall have the authority to take any action that under Oklahoma law can only be taken by the Board of Directors. Sections 5.4, 5.5, 5.6, 5.7, 5.8 and 5.9 shall also apply to committees and their members.

Section 5.11. Informal Action by Directors. Any action required by the Oklahoma General Corporation Act to be taken at a meeting of the Board of Directors of the Corporation, or any other action which may be taken at a meeting of the Board of Directors or a committee thereof, may be taken without a meeting if a consent in writing, setting forth the action so taken, shall be signed by all of the directors entitled to vote with respect to the subject matter thereof, or by all members of such committee, as the case may be.

5.11.1. Effective Date. The consent shall be evidenced by one or more written approvals, each of which sets forth the action taken and bears the signature of one or more directors. All the approvals evidencing the consent shall be delivered to the secretary to be filed in the corporate records. The action taken shall be effective when all the directors have approved the consent unless the consent specifies a different effective date.

5.11.2. Effect of Consent. Any consent signed by all the directors or all the members of a committee shall have the same effect as a unanimous vote, and may be stated as such in any document filed with the Secretary of State under the Oklahoma General Corporation Law.

Section 5.12. Meeting by Conference Telephone. Members of the Board of Directors or of any committee of the Board of Directors may participate in and act at any meeting of the board or committee by means of conference telephone or other communications equipment through which all persons participating in the meeting can hear each other. Participation in such a meeting shall be equivalent to attendance and presence in person at the meeting of the person or persons so participating.

Section 5.13. Compensation. The Board of Directors, by the affirmative vote of a majority of the directors then in office, and irrespective of any personal interest of any of its members, shall have authority to establish reasonable compensation of all directors for services to the Corporation as directors, officers, or otherwise.

ARTICLE 6.
OFFICERS

Section 6.1. Number. The officers of the Corporation may consist of a president, one or several vice presidents, a treasurer, one or more assistant treasurers (if elected by the Board of Directors), a secretary, one or more assistant secretaries (if elected by the Board of Directors), and such other officers (including, if so directed by a resolution of the Board of Directors, a

Chairman of the Board) as may be elected in accordance with the provisions of this Article. Any two or more offices may be held by the same person.

Section 6.2. Election and Term of Office. The officers of the Corporation shall be elected annually by the Board of Directors at the first meeting of the Board of Directors held after each annual meeting of shareholders. If the election of officers shall not be held at such meeting, such election shall be held as soon thereafter as reasonably practicable. Subject to the provisions of Section 6.3 hereof, each officer shall hold office until the last to occur of the next annual meeting of the Board of Directors or until the election and qualification of his or her successor.

Section 6.3. Removal of Officers. Any officer elected or appointed by the Board of Directors may be removed by the Board of Directors whenever in its judgment the best interests of the Corporation would be served thereby, but such removal shall be without prejudice to the contract rights, if any, of the person so removed.

Section 6.4. Vacancies; New Offices. A vacancy occurring in any office may be filled and new offices may be created and filled, at any time, by the Board of Directors.

Section 6.5. President and Chief Executive Officer. The president shall be the chief executive officer of the Corporation. He or she shall be in charge of the day to day business and affairs of the Corporation, subject to the direction and control of the Board of Directors. He or she shall preside at all meetings of the Board of Directors. He or she shall have the power to appoint such agents and employees as in his or her judgment may be necessary or proper for the transaction of the business of the Corporation. He or she may sign: (i) with the secretary or other proper officer of the Corporation thereunto authorized by the Board of Directors, stock certificates of the Corporation the issuance of which shall have been authorized by the Board of Directors; and (ii) any contracts, deeds, mortgages, bonds, or other instruments which the Board of Directors has authorized to be executed, according to the requirements of the form of the instrument.

Section 6.6. Vice President(s). The vice president (or in the event there is more than one vice president, each of them) shall assist the president in the discharge of his or her duties as the president may direct, and shall perform such other duties as from time to time may be assigned to him or her (or them) by the president or the Board of Directors. In the absence of the president, the vice president (or vice presidents, in the order of their election), shall perform the duties and exercise the authority of the president.

Section 6.7. Treasurer. The treasurer shall have charge and custody of and be responsible for all funds and securities of the Corporation, receive and give receipts for moneys due and payable to the Corporation from any source whatsoever, and deposit all such moneys in the name of the Corporation in such banks, trust companies or other depositaries as shall be selected in accordance with the provisions of Article 8 of these Bylaws, have charge of and be responsible for the maintenance of adequate books of account for the Corporation, and, in general, perform all duties incident to the office of treasurer and such other duties not inconsistent with these By-laws as from time to time may be assigned to him or her by the president or the Board of Directors.

Section 6.8. Secretary. The secretary shall keep the minutes of the shareholders' and the Board of Directors' meetings, see that all notices are duly given in accordance with the provisions of these By-laws or as required by law, have general charge of the corporate records and of the seal of the Corporation, have general charge of the stock transfer books of the Corporation, keep a register of the post office address of each shareholder which shall be furnished to the secretary by such shareholder, sign with the president, or any other officer thereunto authorized by the Board of Directors, certificates for shares of the Corporation, the issuance of which shall have been authorized by the Board of Directors, and any contracts, deeds, mortgages, bonds, or other instruments which the Board of Directors has authorized to be executed, according to the requirements of the form of the instrument, and, in general, perform all duties incident to the office of secretary and such other duties not inconsistent with these By-laws as from time to time may be assigned to him or her by the president or the Board of Directors.

Section 6.9. Assistant Treasurers and Assistant Secretaries. The Board of Directors may elect one or more than one assistant treasurer and assistant secretary. In the absence of the treasurer, or in the event of his or her inability or refusal to act, the assistant treasurers, in the order of their election, shall perform the duties and exercise the authority of the treasurer. In the absence of the secretary, or in the event of his or her inability or refusal to act, the assistant secretaries, in the order of their election, shall perform the duties and exercise the authority of the secretary. The assistant treasurers and assistant secretaries, in general, shall perform such other duties not inconsistent with these By-laws as shall be assigned to them by the treasurer or the secretary, respectively, or by the president or the Board of Directors.

Section 6.10. Compensation. The compensation of all directors and officers shall be fixed from time to time by the Board of Directors. No officer shall be prevented from receiving such compensation by reason of the fact that he or she is also a director of the Corporation. All compensation so established shall be reasonable and solely for services rendered to the Corporation.

ARTICLE 7.
FISCAL MATTERS

Section 7.1. Fiscal Year. The fiscal year of the Corporation shall begin on the first day of January in each year.

Section 7.2. Contracts. The Board of Directors may authorize any officer or officers, agent or agents, to enter into any contract or execute and deliver any instrument, in the name of and on behalf of the Corporation, and such authority may be general or confined to specific instances.

Section 7.3. Loans and Indebtedness. No substantial or material loans shall be contracted on behalf of the Corporation and no evidences of indebtedness shall be issued in its name unless authorized by a resolution of the Board of Directors. Such authority may be general or confined to specific instances.

Section 7.4. Checks. Drafts. Etc. All checks, drafts or other orders for the payment of money,

notes or other evidences of indebtedness issued in the name of the Corporation shall be signed by such officer or officers, agent or agents of the Corporation as the Board of Directors shall from time to time designate.

Section 7.5. Deposits. All funds of the Corporation not otherwise employed shall be deposited from time to time to the credit of the Corporation in such banks, trust companies or other depositaries as the Board of Directors may select.

ARTICLE 8.
GENERAL PROVISIONS

Section 8.1. Dividends and Distributions. The Board of Directors may from time to time declare or otherwise authorize, and the Corporation may pay distributions in money, shares or other property on its outstanding shares in the manner and upon the terms, conditions and limitations provided by law or certificate of incorporation.

Section 8.2. Corporate Seal. The Board of Directors may provide a corporate seal which shall be in the form of a circle and shall have inscribed thereon the name of the Corporation and the words "Corporate Seal, Oklahoma." The seal may be used by causing it or a facsimile thereof to be impressed or affixed or in any manner reproduced.

Section 8.3. Waiver of Notice. Whenever any notice is required to be given by law, certificate of incorporation or under the provisions of these By-laws, a waiver thereof in writing, signed by the person or persons entitled to such notice, whether before or after the time stated therein, shall be deemed equivalent to the giving of such notice.

Section 8.4. Headings. Section or paragraph headings are inserted herein only for convenience of reference and shall not be considered in the construction of any provision hereof.

Exhibit 10.07

OGE ENERGY CORP.
SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN
(As Amended and Restated Effective March 1, 2002)

Purpose

The purpose of this Supplemental Executive Retirement Plan is to promote the best interests of the Company by enabling the Company: (a) to attract to its key management positions persons of outstanding ability, and (b) to retain in its employ those persons of outstanding competence who occupy key executive positions and who in the past contributed and who continue in the future to contribute materially to the success of the business by their ability, ingenuity and industry. This Supplemental Executive Retirement Plan was established to accomplish such purpose effective January 1, 1993, by Oklahoma Gas and Electric Company and assumed by the Company on November 18, 1998. The Company hereby amends and restates the Supplemental Executive Retirement Plan effective March 1, 2002, as provided herein. It is intended to be a plan which is unfunded and is maintained by the Company primarily for the purpose of providing deferred compensation for a select group of management or highly compensated employees.

ARTICLE 1

Definitions

The following words and phrases as used herein shall have the following meanings, unless a different meaning is plainly required from time to time.

1.1 "Board of Directors" means the Board of Directors of OGE Energy Corp. as constituted from time to time.

1.2 "Committee" means the Compensation Committee of the Board of Directors.

1.3 "Company" means OGE Energy Corp. and any of its domestic subsidiaries and divisions, as designated by the Board of Directors, and any successor of OGE Energy Corp. under the terms of Section 7.3.

1.4 "Company's Pension Plan" means the OGE Energy Corp. Retirement Plan, as amended from time to time.

1.5 “Compensation” means, at any date, the Participant’s Compensation as defined under the Company’s Pension Plan as in effect with respect to that Participant on such date.

1.6 “Effective Date” means January 1, 1993.

1.7 “Final Average Compensation” means the monthly average of the Participant’s Compensation earned during the last 36 consecutive months of employment with the Company. If the Participant does not have 36 consecutive months of employment, “Final Average Compensation” shall be the average Compensation for his period of employment with the Company.

1.8 “Normal Retirement Date” means the first day of the month coinciding with or following the Participant’s 65th birthday.

1.9 “Other Pension Benefits” means benefits paid or payable to a Participant from the Company’s Pension Plan, the Company Restoration of Retirement Income Plan, the qualified or nonqualified pension plans of any prior employer unrelated to the Company, or any governmental or church pension plan as defined in Sections 3(32) and 3(33) of the Employee Retirement Income Security Act of 1974, as amended (“ERISA”); excluding, however, any portion of such benefits attributable to the Participant’s own contributions as determined by the plan’s administrator or other responsible agent. Regardless of the form, amount or timing of payment, “Other Pension Benefits” shall be calculated, based on actuarial assumptions approved from time to time by the Committee, by the Company’s actuary as of the Participant’s commencement of benefits under this Plan on the basis of a 100% joint and survivor annuity for married Participants, and on the basis of a 10-year certain and life annuity for unmarried Participants.

1.10 “Participant” means an employee of the Company specifically designated by the Committee to be covered under this Plan and who continues to fulfill all requirements for participation.

1.11 “Plan” means the Supplemental Executive Retirement Plan as herein set forth and as it may be amended from time to time.

1.12 “Service” means, at any date, the Participant’s “Credited Service” as determined under the Company’s Pension Plan, as in effect with respect to such Participant on that date, plus service with any immediate predecessor company which was acquired, merged, or consolidated with the Company, as permitted in the sole discretion of the Committee.

1.13 “Social Security Benefits” means the annual primary insurance amount estimated by the Committee to be payable to the Participant at his social security retirement age under the Federal Social Security Act.

1.14 “Surviving Spouse” means the spouse to whom the Participant is lawfully married at the time of his death before commencement of benefits under this Plan, or to whom the Participant was lawfully married both at the time of his commencement of benefits under this Plan and at the time of his death.

1.15 "Totally and Permanently Disabled" means that the Participant is eligible to receive disability retirement benefits under the Company's Pension Plan.

ARTICLE 2

Retirement Benefits

2.1 Normal Retirement Benefit

(a) Upon a vested Participant's termination of employment with the Company on or after his Normal Retirement Date, the Company shall pay retirement benefits to the Participant in such amounts and at such times as hereinafter described.

(b) The normal retirement benefit payable to the Participant in monthly amounts during his lifetime and commencing when benefits commence (or are made if payable in a lump sum) to him under the Company's Pension Plan shall equal 65% of the Participant's Final Average Compensation, offset or reduced by the following:

(i) Other Pension Benefits; and

(ii) Social Security Benefits.

(c) Benefit payments which have commenced under the terms of this Plan shall not be affected by any subsequent change in Other Pension Benefits under a plan of the Company, except that if such benefits are reduced, the benefits payable under this Plan shall be increased by an actuarially equivalent amount of the reduction in such benefits.

2.2 Early Retirement Benefit

(a) Any vested Participant who terminates employment with the Company prior to his Normal Retirement Date shall be entitled to commence benefits under this Plan when benefits commence (or are made if payable in a lump sum) to him under the Company's Pension Plan; provided, however, that in no event shall benefits commence under this Plan before the Participant attains age 55. If benefits commence prior to the Participant's Normal Retirement Date, the amount of the Participant's benefit under this Plan shall be reduced according to the following schedule:

Age at Commencement of Benefits	Benefit as a % of Final Average Compensation
55	32%
56	38%
57	44%
58	50%
59	54%
60	58%
61	60%
62	62%
63	63%
64	64%

(b) Benefits payable under Section 2.2(a) shall be reduced or offset as described in Section 2.1(b).

2.3 Disability Retirement Benefit

A vested Participant who becomes Totally and Permanently Disabled shall be entitled to benefits under this Plan as set forth in Section 2.1 when he commences benefits (or when benefits are paid to him if payable in a lump sum) under the Company's Pension Plan.

ARTICLE 3

Death Benefits

3.1 The following death benefits shall be payable to a Surviving Spouse under the Plan:

(a) Upon the death of a vested Participant prior to his commencement of benefits under this Plan, the Participant's Surviving Spouse shall receive a life annuity equal to 100% of the Participant's Normal or Early Retirement Benefit as calculated under Section 2.1 or 2.2, whichever is applicable, based on the Participant's age at date of death, except that if the Participant is less than age 55 at death, (i) the death benefit payable to the Surviving Spouse hereunder shall not commence until the Participant would have attained age 55 had the Participant survived and (ii) the death benefit payable shall be equal to 100% of the Early Retirement Benefit as calculated under Section 2.2 as if the Participant were age 55 at death.

(b) Upon the death of a vested Participant after commencement of benefits under this Plan, the Participant's Surviving Spouse shall receive a life annuity equal to 100% of the monthly benefit payable to the Participant under this Plan.

(c) Benefits payable under this Plan to a Surviving Spouse shall be terminated at the end of the month in which the death of the Surviving Spouse occurs.

(d) If the Surviving Spouse is more than ten years younger that the Participant at the time of the Participant's death, benefits payable to the Surviving Spouse under the Plan shall be reduced by 50%.

3.2 The Surviving Spouse's benefits provided herein shall be in addition to any pre- or post-retirement life insurance benefits under the Company's insurance programs.

3.3 In the event of the death of a Participant receiving a 10-year certain and life annuity prior to receiving payment under the Plan for 120 months, benefits under this Plan shall be payable to the Participant's estate or as assigned by the legal representative of the estate until ten years have passed from the date the Participant started receiving benefits.

ARTICLE 4

Vesting

4.1 Any participant having completed a minimum of 10 years of Service with the Company and attained age 55 while employed by the Company shall be considered vested in rights to retirement benefits as provided in this Plan, subject to the provisions of Section 7.2 of this Plan.

4.2 By written action of the Committee and in its sole discretion, the requirement of 10 years of Service with the Company and/or attainment of age 55 for vesting purposes under the terms of this Plan may be partially or fully waived for a specified Participant on such terms as the Committee may determine.

ARTICLE 5

Method of Payment of Benefits

5.1 Benefits under this Plan for a Participant who is not married when benefits commence to him under this Plan shall be payable monthly for the life of the Participant in the form of a 10-year certain and life annuity. Benefits under this Plan for a Participant who is married when benefits commence to him under this

Plan shall be payable in the form of a 100% joint and survivor annuity for the life of the Participant and his spouse. Lump sum payments shall not be permitted under the Plan.

5.2 The undertakings of the Company herein constitute an unsecured promise of the Company to make the payments as provided in the Plan. This Plan is unfunded and no current beneficial interest in any asset of the Company shall accrue to any Participant or other person under the terms of this Plan. All Participants shall be entitled to the benefits provided by the Plan. It is the intent of the Company that the total cost of providing the benefits under this Plan will be borne by the Company.

ARTICLE 6

Administration

6.1 The Committee shall have sole and absolute discretionary power and authority to interpret, construe and administer this Plan, to adopt appropriate procedures and to make all decisions, including deciding all questions of fact, necessary or proper in its judgment to carry out the terms of this Plan. The Committee's interpretation and construction hereof, and actions hereunder, including any valuation of the amount or recipient of the payments to be made thereunder, shall be binding and conclusive on all persons for all purposes. The Company's Chief Accounting Officer, shall act as the

Committee's agent in administering this Plan. Neither the Company, or its officers, employees or directors, nor the Committee or any member thereof shall be liable to any person for any action taken or omitted in connection with the interpretation and administration of this Plan.

6.2 Each Participant shall furnish to the Committee such information as it may from time to time request for the purpose of the proper administration of this Plan.

6.3 The OGE Energy Corp., by action of the Board of Directors, reserves the exclusive right to amend, modify, alter or terminate this Plan in whole or in part without notice to the Participants. No such termination, modification or amendment shall terminate or diminish the amount of benefits then being paid, or to be paid on subsequent termination of employment, to any Participant or Surviving Spouse.

6.4 OGE Energy Corp. shall be the "Administrator" of the Plan for purposes of ERISA.

ARTICLE 7

General Provisions

7.1 This Plan shall not be deemed to give any Participant or other person in the employ of the Company any right to be retained in the employment of the Company, or to interfere with the right of the Company to terminate any Participant or such other person at any time and to treat him without regard to the effect which such treatment might have upon him as a Participant in the Plan.

7.2 In the event a Participant is discharged for cause involving illegal or fraudulent acts, such discharge may result in forfeiture of all benefits and rights under the Plan, in the sole discretion of the Committee.

7.3 The rights, privileges, benefits and obligations under this Plan are intended to be, and shall be treated as, legal obligations of the Company and binding upon the Company, its successors and assigns, including successors by corporate merger, consolidation, reorganization or otherwise.

7.4 Copies of this Plan, together with copies of any approved procedures for administration will be furnished to each Participant together with an annual statement of benefits over the signature of the Chairman of the Board or his designee.

7.5 This Plan was approved initially by resolution of the Board of Directors of Oklahoma Gas and Electric Company at a regular meeting on November 9, 1993 to be effective as of January 1, 1993 and was subsequently assumed and amended by resolutions of the Board of Directors.

7.6 The provisions of this Plan shall be construed according to the law of the State of Oklahoma excluding the provisions of any such laws that would require the application of the laws of another jurisdiction.

7.7 The masculine pronoun wherever used shall include the feminine. Wherever any words are used herein in the singular, they shall be construed as though they were also used in the plural in all cases where they shall so apply.

7.8 The titles to articles and headings of sections of this Plan are for convenience of reference and in case of any conflict the text of this Plan, rather than such titles and headings, shall control.

ARTICLE 8

Claims Procedure

8.1 Initial Claims Procedure

The Participant or his Surviving Spouse shall follow such procedures for making a claim as are provided by the Committee. The Committee shall make a decision upon each claim within 90 days of its receipt of such claim. If the claim is approved, the Committee shall determine the extent of benefits and initiate payment thereof. In the event that no action is taken on the applicant's initial application for benefits within the period specified in this Section 8.1, the claim shall be deemed denied, and the applicant's appeal rights under Section 8.3 will be in effect as of the end of such period.

8.2 Notice of Denial of Claim

If an application for benefits under Section 8.1 is denied in whole or in part, the Committee shall provide the applicant with a written notice of denial, setting forth: (a) the specific reason or reasons the claim was denied, (b) a specific reference to pertinent provisions of the Plan upon which the denial was based, (c) a description of the additional material or information (if any) necessary to perfect the claim, together with an explanation of why such material or information is necessary, and (d) an explanation of the Plan's review procedure. This written notice of denial shall be furnished within 90 days after receipt of the claim by the Committee unless specific circumstances require an extension of time for processing. If an extension is required, written notice of the extension shall be furnished prior to the termination of the initial 90-day period. If no event shall such extension exceed a period of 90 days from the end of such initial period. The extension notice shall indicate the special circumstances requiring an extension of time and the date by which the Committee expects to render the final decision.

8.3 Claims Review Procedure

Within 60 days after receipt of a notice of denial, the applicant or his duly authorized representative may file a written notice of appeal of such denial with the Committee. Such notice of appeal must set forth the specific reasons for the appeal. In addition, within such appeal period the applicant or his duly authorized representative shall be provided, upon written request and free of charge, reasonable access to, and copies of, all documents, records, and other information relevant to the claim for benefits and may submit written comments, documents, records and other information relating to the claim. The 60-day period within which the request for review must be filed may be extended if the nature of the benefit which is the subject of the claim and other attendant circumstances so warrant and the 60-day limitations period would otherwise be unreasonable. In its sole discretion, the Committee may grant the applicant an oral hearing on his

appeal. In considering the claim on review, the Committee will take into account all documents and information related to the claim that were submitted by the applicant and shall deliver to the applicant, or authorized representative, a written decision on the claim within 60 days after the receipt of the request for review, except that if there are special circumstances which require an extension of time, the 60-day period may be extended to 120 days. If such extension is required, written notice shall be furnished to the applicant, or authorized representative, prior to the termination of the initial 60-day period. The decision shall be written in a manner calculated to be understood by the claimant, include the specific reason or reasons for the decision and contain a specific reference to the pertinent Plan provisions upon which the decision is based, a statement that an applicant, or his/her authorized representative, shall have reasonable access to, and be entitled to receive, upon request and free of charge, copies of, all documents, records, and other information relevant to the applicant's claim for benefits, and a statement describing the claimant's right to bring an action under Section 502(a) of ERISA.

AMENDMENT NO. 1
TO THE OGE ENERGY CORP.
SUPPLEMENTAL EXECUTIVE RETIREMENT PLAN
(As Amended and Restated Effective March 1, 2002)

OGE Energy Corp., an Oklahoma corporation (the "Company"), in accordance with the authority reserved to the Company under Section 6.3 of the OGE Energy Corp. Supplemental Executive Retirement Plan (As Amended and Restated Effective March 1, 2002) (the "Plan"), hereby amends the Plan, effective as of December 31, 2004, in the following respects:

1. By adding the phrase "prior to January 1, 2005" after the phrase "designated by the Committee" where it appears in Section 1.10 of the Plan.

2. By adding a new Section 2.4 to the Plan after Section 2.3 as follows:

"2.4 Limitations

Notwithstanding the foregoing provisions of this Article 2 or of Article 3 or any other provision of this Plan, benefits shall cease to accrue under this Plan as of December 31, 2004 and the benefits payable under this Plan to any Participant who terminates employment with the Company after December 31, 2004 or his Surviving Spouse or other person entitled to death benefits under Article 3, as computed in accordance with the foregoing provisions of this Article 2 or of Article 3, as applicable, shall be limited to and shall not exceed the amount that is payable to the recipient with respect to the amounts determined by the Committee to have been deferred under the Plan by the Participant before January 1, 2005 within the meaning of Section 885(d) of the American Jobs Creation Act of 2004 and the regulations and guidance issued thereunder with respect to Section 409A of the Code (the "Grandfathered Benefit")."

IN WITNESS WHEREOF, OGE Energy Corp. has caused this instrument to be executed in its name by its duly authorized officer as of the 31st day of December, 2004.

OGE Energy Corp.

By: /s/ Peter B. Delaney

Title: Executive Vice President and

Chief Operating Officer

Exhibit 10.23

OGE ENERGY CORP.
AMENDMENT NO. 1 TO THE OGE ENERGY CORP.
2003 STOCK INCENTIVE PLAN
DATED NOVEMBER 17, 2004

OGE Energy Corp., an Oklahoma corporation (the "Company"), by action of its Board of Directors taken in accordance with the authority granted to it by Section 11 of the OGE Energy Corp. 2003 Stock Incentive Plan (the "Plan"), hereby amends the Plan in the following respect effective as of November 17, 2004:

1. Section 10 is deleted in its entirety and the following is inserted in lieu thereof:

“Section 10. Loans.

The Company shall not make any loan to any participant in connection with the exercise of Stock Options under the Plan or otherwise in connection with any other Awards under the Plan."

IN WITNESS WHEREOF, OGE Energy Corp. has caused this instrument to be signed in its name by a duly authorized officer on this 17th day of November, 2004.

OGE Energy Corp.

By: /s/ Carla D. Brockman

Carla D. Brockman
Corporate Secretary

Exhibit 10.24

INTRASTATE
FIRM NO-NOTICE, LOAD FOLLOWING TRANSPORTATION AND STORAGE
SERVICES AGREEMENT

This Intrastate Firm No-Notice, Load Following Transportation and Storage Services Agreement (this “Agreement”) is made and entered into as of this 1st day of May, 2003, between **ENOGEX INC**., hereinafter referred to as “TRANSPORTER” and **OKLAHOMA GAS & ELECTRIC COMPANY**, hereinafter referred to as SHIPPER”. TRANSPORTER and SHIPPER may be referred to sometimes as “Party” and collectively as “Parties”. All Exhibits referred to in this Agreement are attached hereto and incorporated herein by reference.

W I T N E S S E T H:

WHEREAS, TRANSPORTER represents it is an intrastate pipeline within the meaning of Section 2(16) of the Natural Gas Policy Act of 1978 (“NGPA”);

WHEREAS, SHIPPER operates electric power generation plants (“Generation Plants”) located in Oklahoma, and further defined in Exhibit “B” hereto;

WHEREAS, TRANSPORTER operates facilities for the transportation and storage of natural gas in the State of Oklahoma (“Transportation System”);

WHEREAS, effective April 30, 2002, the Parties entered into that certain Binding Letter Agreement for firm no-notice, load following transportation services on the Transportation System, whereby the Parties agreed to set forth the provisions and conditions of such services in a definitive agreement;

WHEREAS, effective August 9, 2002, TRANSPORTER purchased and began operations of certain storage facilities and assets located near Stuart, Oklahoma in Hughes County, Oklahoma, from Central Oklahoma Oil and Natural Gas Corporation;

WHEREAS, SHIPPER desires TRANSPORTER to provide additional firm no-notice, load following transportation and storage services, not previously contracted for or contemplated in the Binding Letter Agreement;

WHEREAS, the Parties execute and enter into this Agreement as the Intrastate Firm Service Agreement referenced in the Binding Letter Agreement; and,

WHEREAS, SHIPPER has requested that TRANSPORTER receive, transport, store and redeliver certain quantities of gas available to SHIPPER, and TRANSPORTER is agreeable to providing such firm no-notice, load following transportation and storage services in accordance with the terms hereof.

NOW, THEREFORE, in consideration of the premises and of the mutual covenants herein contained, the Parties hereto covenant and agree as follows:

1. <u>Transportation of Gas.</u>

a. SHIPPER shall have the right, but not the obligation, to transport on the Transportation System, on any day covered by this Agreement, a Maximum Daily Quantity (“MDQ”) of gas as set forth on Exhibit “B”. TRANSPORTER agrees to deliver such quantities of gas as SHIPPER shall require at the Point(s) of

Delivery as described on Exhibit "B" hereto, each day, not to exceed a quantity which, after reduction for System Fuel (as defined in Section 4 herein), is equal to the total quantities of gas nominated at the Point(s) of Receipt by SHIPPER and confirmed by TRANSPORTER, which quantities are referred to herein as the "Confirmed Supply Nomination Quantity", plus the Daily Storage Service Quantity, as set forth in Exhibit "G" hereto.

b. Subject to the limitations contained herein, SHIPPER shall have the right to receive on the Transportation System during any hour of any day covered hereby, such amount of gas as SHIPPER shall require during such hour at the Point(s) of Delivery, up to the MHQ, as specified in Exhibit "B". However, in no event shall the flow rate (expressed in MMBtu per day) exceed the Confirmed Supply Nomination Quantity, plus the Hourly Storage Service Quantity.

c. The service provided hereunder shall be firm and without interruption during the entire term of this Agreement, subject to the terms herein. It is understood that no shipper shall have any higher level of firm transportation or storage service than SHIPPER. In addition, the service shall be available on a "no-notice", load following basis, allowing SHIPPER to receive unscheduled quantities of natural gas at the Point(s) of Delivery for the daily and hourly swings related to the generation of electricity, subject to the terms herein.

2. Overrun Service.

a. Authorized Overrun Service — SHIPPER may, if authorized by TRANSPORTER, transport gas in excess of the quantities set forth in Section 1 hereof, or exceed the Storage Service Quantities set forth in Exhibit "G" hereto, on an interruptible basis as set forth in this Section 2(a). The gas transported, injected or withdrawn in excess of the quantities described herein pursuant to this Section 2(a) shall be considered "Authorized Overrun Gas" to be transported, injected or withdrawn on an interruptible basis under the provisions of TRANSPORTER'S Statement of Operating Conditions ("Statement of Operating Conditions"), which are incorporated herein.

Each day that Authorized Overrun Gas service is provided to SHIPPER, SHIPPER agrees to pay TRANSPORTER an Authorized Overrun Gas charge per MMBtu of the maximum allowable rate as authorized by FERC for Section 311 service on the Transportation System, as may be amended from time to time, plus System Fuel applied to the Authorized Overrun Gas received by TRANSPORTER. For any Authorized Overrun Gas for storage, SHIPPER agrees to pay TRANSPORTER an Authorized Overrun Gas charge of $0.60 per MMBtu, or such other amount as the Parties may mutually agree, for each MMBtu injected which causes the inventory to exceed 8,300,000 MMBtu, as shown on Exhibit "G" hereto.

b. Excess Receipts or Deliveries — In the event receipts or deliveries to SHIPPER are greater than the service defined herein, then such quantities shall be considered "Excess Receipts or Deliveries". TRANSPORTER is not obligated to allow SHIPPER to exceed the receipts or deliveries set forth herein.

Each day that Excess Deliveries occur, SHIPPER agrees to pay TRANSPORTER for such Excess Deliveries a price per MMBtu as set forth below. Each day that Excess Receipts occur, TRANSPORTER agrees to pay SHIPPER for such Excess Receipts a price per MMBtu as set forth below:

SHIPPER'S Excess Deliveries	**SHIPPER'S Excess Receipts**
Greater of actual cost or 125% of Delivery Index Price	Lesser of actual resale price or 75% of Receipt Index Price

"Delivery Index Price" shall mean the highest of the Midpoint daily index prices, as published in *Gas Daily*, for Reliant — West, and Panhandle, Tx.-Okla., as published on the day of flow and the subsequent two (2) business days. For any day(s) that the Delivery Index Price is not published by *Gas Daily*, the Delivery Index Price for such day(s) shall be determined by the prices published by *Gas Daily* immediately subsequent to such day(s).

"Receipt Index Price" shall mean the lowest of the Midpoint daily index prices, as published in *Gas Daily*, for Reliant — West, and Panhandle, Tx,-Okla., as published on the day of flow and the subsequent two (2) business days. For any day(s) that the Receipt Index Price is not published by *Gas Daily*, the Receipt Index Price for such day(s) shall be determined by the prices published by *Gas Daily* immediately subsequent to such day(s).

c. If TRANSPORTER fails to deliver quantities of gas on any day that it is required to deliver hereunder, unless excused by the terms hereof, TRANSPORTER will pay SHIPPER for quantities not delivered an amount equal to the greater of SHIPPER'S actual cost to procure delivered replacement gas or purchased power or 125% of the Delivery Index Price, as defined in Section 2(b) above. TRANSPORTER shall not assess any discount or penalty against SHIPPER for any Excess Receipts or Deliveries on the Transportation System due to TRANSPORTER'S failure to perform hereunder. It is understood that no shipper shall have any higher level of firm transportation or storage service than SHIPPER.

3. Point(s) of Receipt and Delivery. Gas delivered by SHIPPER hereunder shall be delivered to TRANSPORTER at the point or points which are hereinafter referred to as the "Point(s) of Receipt" and which are specifically set forth and identified in Exhibit "A" hereto, at as constant a rate as practicable. Gas delivered hereunder by TRANSPORTER shall be delivered to SHIPPER'S Generation Plants which are hereinafter referred to as the "Point(s) of Delivery" and which are specifically set forth and identified in the Exhibit "B" hereto, at a pressure no less than the minimum pressure as set forth in Exhibit "B".

[Confidential information has been omitted and filed separately with the Securities and Exchange Commission.]

If SHIPPER desires to deliver supplies of gas to other SHIPPER operated power generation plants located on intrastate pipelines other than the Transportation System, then SHIPPER may, if authorized by TRANSPORTER, transport gas on an interruptible basis under the terms and conditions of this Agreement for deliveries to the available intrastate pipeline interconnection points on the Transportation System. SHIPPER acknowledges and understands that any quantities of gas transported pursuant to this paragraph shall be for the sole and exclusive use and consumption at SHIPPER'S operated power generation plants, and SHIPPER shall not resell any such quantities. Additionally, SHIPPER shall be solely responsible for, and indemnify TRANSPORTER from and against, any pipeline imbalance charges, fees or penalties assessed as a result of transporting quantities of gas pursuant to this paragraph.

In the event retroactive adjustments or reallocations of quantities received or delivered hereunder are made by TRANSPORTER, and to the extent SHIPPER relies on measurement information provided by TRANSPORTER to determine the quantities received or delivered pursuant to this Agreement, TRANSPORTER agrees to waive any charges that may be assessed pursuant to Section 2(b) above.

4. Rates and Charges. SHIPPER agrees to pay TRANSPORTER each month, during the term of this Agreement, (i) Demand Fees as set forth on Exhibit "C" hereto, and (ii) the maximum allowable System Fuel, as defined below, and as approved by FERC from time to time, applied to the volumes received by TRANSPORTER at the Point(s) of Receipt. The System Fuel referenced herein and in Section 1 above is in addition to the Demand Fees.

"System Fuel" shall mean and equal SHIPPER'S pro-rata share of the actual fuel and loss and unaccounted for gas on the Transportation System, as approved by FERC from time to time, which pro-rata share shall be calculated based on the volumes of gas received by TRANSPORTER at the Point(s) of Receipt. SHIPPER shall provide the System Fuel in-kind to TRANSPORTER.

5. **Term.** Subject to the other provisions of this Agreement, this Agreement is effective as of April 30, 2002, and will remain in full effect for a primary term of seven (7) years, ending April 30, 2009 ("Primary Expiration Date"). The services contracted for in the Binding Letter Agreement became effective as of April 30, 2002. The additional transportation and storage services being provided herein that were not contracted for or contemplated in the Binding Letter Agreement have the following effective dates: storage services — effective August 1, 2002; additional transportation services (additional MDQ and MHQ above the amounts set forth in the Binding Letter Agreement) — effective date May 1, 2003. After the Primary Expiration Date, this Agreement will remain in effect from year to year thereafter unless terminated prior to the commencement of the next succeeding annual period by either Party on 180 days prior written notice to the other Party.

6. **General Terms for Intrastate Service.**

a. TRANSPORTER'S Statement of Operating Conditions on file with the Federal Energy Regulatory Commission ("FERC"), as may be amended from time to time by

TRANSPORTER, is hereby incorporated into this Agreement and made a part hereof for all purposes applicable to Intrastate Service. The incorporation of the Statement of Operating Conditions is for the convenience of the Parties only, and shall not imply or serve as evidence that either TRANSPORTER or this Agreement is subject to any authority of the FERC. If the Statement of Operating Conditions or any respective amendment thereto, conflicts with the terms set forth in this Agreement, the terms of this Agreement shall control.

b. SHIPPER represents and warrants that neither the receipt, transportation nor delivery of gas under this Agreement shall subject TRANSPORTER or its facilities, or any entity with whom TRANSPORTER has contracted in order to provide transportation service hereunder, or such entity's facilities, to regulation under the Natural Gas Act of 1938 or the NGPA. Shipper further represents and warrants that any gas transported to the Point(s) of Receipt by an interstate pipeline shall be transported by said interstate pipeline pursuant to Section 311 of the NGPA.

7. **Authority.** SHIPPER represents and warrants that it has the requisite corporate authority to enter into this Agreement and incur the obligations herein.

8. **Notices.** Except as herein otherwise provided, any notice, request, demand, statement, routine communications, invoice or bill provided for under this Agreement or the Exhibits hereto shall be in writing and delivered to the Parties at the addresses or facsimile numbers identified on Exhibits "D" and "E" attached hereto. Notice shall be deemed given when physically delivered to the other Party in person, when transmitted to the other Party by confirmed facsimile transmission, or when deposited in the U. S. Mail or with a delivery service, postage prepaid. Either Party may change its address or facsimile number by providing notice of same in accordance herewith. Notices under this Agreement are to be made to the persons designated by each Party on Exhibits "D" or "E" until each Party designates other persons to receive such notices.

9. **Government Regulations.** The Parties hereto recognize that this Agreement has been entered into by TRANSPORTER in the good faith understanding that all acts, obligations, and intrastate services performed or to be performed by TRANSPORTER hereunder, and the charges therefore, are exempt from the regulation of FERC or any successor federal governmental authority, and SHIPPER warrants to TRANSPORTER that the transportation or status of the gas prior to and after the transportation service by TRANSPORTER will not subject TRANSPORTER to such regulations. TRANSPORTER reserves the right to terminate the Agreement immediately if, in the opinion of counsel for TRANSPORTER, any act shall occur or be threatened which is in any way inconsistent with such understanding.

10. **Previous Agreements.** This Agreement replaces and supersedes any prior discussions, negotiations, representations or agreements, whether oral or written, between TRANSPORTER and SHIPPER, if any, with respect to the transportation, and, if applicable, compression of gas from any source of supply identified on Exhibit "A." The Parties agree that such previous agreements are terminated as of May 1, 2003; provided, however, that any outstanding gas balances or payment obligations related to said previous agreements shall be resolved between the Parties pursuant to the terms of such previous agreements. Any ending balances or inventories, as of May 1, 2003, shall be transferred to this Agreement. Any change,

modification or alteration of this Agreement shall be in writing, signed by the Parties hereto, and no course of dealing between the Parties and no course of performance of said previous agreements shall be construed to alter the terms hereof, except as expressly stated herein. The previous agreements between the Parties that are terminated by this Agreement are as indicated on Exhibit "F".

11. **Damages.** NEITHER PARTY SHALL BE LIABLE OR OTHERWISE RESPONSIBLE TO THE OTHER PARTY FOR PUNITIVE, SPECIAL CONSEQUENTIAL OR INCIDENTAL DAMAGES OR FOR LOST PROFITS WHICH ARISE OUT OF OR RELATE TO THIS AGREEMENT OR THE PERFORMANCE OR BREACH THEREOF.

12. **Confidentiality.** Neither Party shall disclose the terms of this Agreement to a third party (other than the Party's representatives with a need to know such information, such as, counsel, financial advisors and analysts, risk managers, accountants and lenders who have agreed to keep such terms confidential) except in order to comply with any applicable law, order, regulation, or exchange rule; provided, that each Party shall notify the other Party of any proceeding of which it is aware which may result in disclosure and use reasonable efforts to prevent or limit the disclosure. Such confidentiality obligations shall terminate one year after termination of this Agreement.

13. **Assignment.** This Agreement shall be binding upon and inure to the benefit of the Parties and their respective successors and assigns. However, this Agreement shall not be transferred or assigned by either Party to any third party (whether that transfer be by virtue of assignment or change of ownership or control) without the prior written consent of the other Party, which consent shall not be withheld if the proposed assignee has a credit rating from Moody's of at least "Baa3" or Standard and Poor of at least "BBB-", or if the proposed assignee is not rated, then the proposed assignee must meet the credit standards of the non-assigning Party as such standards are employed in the ordinary course of the non-assigning Party's business. No such assignment shall release the assigning Party of its duties and obligations under this Agreement without the non-assigning Party's express written consent, which shall not be unreasonably withheld.

14. **Choice of Law.** The Parties agree that the Agreement shall be governed by and construed in accordance with the laws of the State of Oklahoma, excluding any conflicts of law, rule, or principle that might refer such construction to the laws of another state and that venue shall be in Oklahoma County, Oklahoma, with respect to any cause of action brought under or with respect to this Agreement.

IN WITNESS WHEREOF, the Parties have caused this Intrastate Firm No-Notice, Load Following Transportation and Storage Services Agreement to be executed in duplicate originals as of the date first herein above written.

ENOGEX INC.
("TRANSPORTER")

/s/ E. Keith Mitchell

Name: E. Keith Mitchell

Title: Vice President Sales Support

OKLAHOMA GAS & ELECTRIC COMPANY
("SHIPPER")

/s/ Jack T. Coffman

Name: Jack T. Coffman

Title: Senior Vice President Power Supply

EXHIBIT "A"
POINT(S) OF RECEIPT

This Exhibit "A" to Intrastate Firm No-Notice, Load Following Transportation and Storage Services Agreement by and between ENOGEX INC. ("TRANSPORTER") and OKLAHOMA GAS & ELECTRIC COMPANY ("SHIPPER"), dated May 1, 2003, is for all purposes made a part of said Agreement.

POINT(S) OF RECEIPT

All active intrastate and interstate pipeline interconnects, processing plant tailgates and producer or shipper pools on TRANSPORTER'S Transportation System.

EXHIBIT "B"
POINT(S) OF DELIVERY

This Exhibit "B" to Intrastate Firm No-Notice, Load Following Transportation and. Storage Services Agreement by and between ENOGEX INC. ("TRANSPORTER") and OKLAHOMA GAS & ELECTRIC COMPANY ("SHIPPER"), dated May 1, 2003, is for all purposes made a part of said Agreement.

Gas redelivered by TRANSPORTER to SHIPPER hereunder shall be delivered at the outlet of the Transportation System at the following Point(s) of Delivery:

*[Confidential information has been omitted and filed separately with the Securities and Exchange Commission.]

Point of Delivery	**Station No.**	**MDQ**	**MHQ**	**Minimum Delivery Pressure***
Horseshoe Lake Station Units 9-10	740300	20,000	1,042	*
Horseshoe Lake Station Other Units	740300	160,000	8,625	*
Mustang Station	740500	110,000	5,683	*
Muskogee Station	740700			
* May - Sept. & Dec.- Feb.		55,000	2,558	*
* All other months		15,000	2,558	*
Seminole Station	740800			
* May - Sept.				

& Dec.- Feb.		260,000	16,525[1]	*
* All other months		190,000	16,525[2]	*
Enid Station	740200			
* May - Sept.				
& Dec.- Feb.		11,000	967	*
* All other months		0	0	*
Woodward Station	740900			
* May - Sept.				
& Dec.- Feb.		2,200	217	*
* All other months		0	0	*

[1] Any hourly deliveries to Seminole Station in excess of 12,000 shall be provided by the storage service quantities set forth in Exhibit "G" hereto.

[2] Any hourly deliveries to Seminole Station in excess of 8,000 shall be provided by the storage service quantities set forth in Exhibit "G" hereto.

EXHIBIT "C"
RATES AND CHARGES

This Exhibit "C" to Intrastate Firm No-Notice, Load Following Transportation and Storage Services Agreement by and between ENOGEX INC. ("TRANSPORTER") and OKLAHOMA GAS & ELECTRIC COMPANY ("SHIPPER"), dated May 1, 2003, is for all purposes made a part of said Agreement.

1) SHIPPER shall pay TRANSPORTER **Demand Fees** on a monthly basis, as follows:

(a) $32,300,000 annually, payable in equal monthly installments for transportation services contracted for in the Binding Letter Agreement, effective April 30, 2002;
(b) $12.679.000 annually, payable in equal monthly installments for storage services hereunder, effective August 1, 2002; and,
(c) $1,820,940 annually, payable in equal monthly installments for additional transportation services (additional MDQ and MHQ above the amounts set forth in the Binding Letter Agreement), effective May 1, 2003.

2) SHIPPER shall provide **System Fuel** in-kind to TRANSPORTER as set forth in Section 4 of this Agreement.

3) SHIPPER shall pay TRANSPORTER for **Authorized Overrun Gas** as set forth in Section 2(a) of this Agreement.

4) SHIPPER shall pay TRANSPORTER for **Excess Deliveries** as set forth in Section 2(b) of this Agreement.

5) TRANSPORTER shall pay SHIPPER for **Excess Receipts** as set forth in Section 2(b) of this Agreement.

6) TRANSPORTER shall pay SHIPPER as set forth in Section 2(c) of this Agreement.

EXHIBIT "D"
NOTICES TO TRANSPORTER

This Exhibit "D" to Intrastate Firm No-Notice, Load Following Transportation and Storage Services Agreement by and between ENOGEX INC. ("TRANSPORTER") and OKLAHOMA GAS & ELECTRIC COMPANY ("SHIPPER"), dated May 1, 2003, is for all purposes made a part of said Agreement.

TRANSPORTER:

NOTICES:

Manager, Contract Management
ENOGEX INC.
P. 0. Box 24300
Oklahoma City, OK 73124-0300
Telephone No.: (405) 525-7788
Facsimile No.: (405) 558-4610

Scheduling and Nominations:
ATTN: Manager, Volume Control
Telephone No.: (405) 525-7788
Facsimile No.: (405) 557-7981

PAYMENTS:

By Check Only:
ENOGEX INC.
Dept. # 960045
Oklahoma City, OK 73196-0045

By Electronic Transfer Only:
Bank of Oklahoma
Oklahoma City, OK
ABA #103900036

For Credit To: Enogex Inc.
Account # 814072709

EXHIBIT "E"
NOTICES TO SHIPPER

This Exhibit "E" to Intrastate Firm No-Notice, Load Following Transportation and Storage Services Agreement by and between ENOGEX INC. ("TRANSPORTER") and OKLAHOMA GAS & ELECTRIC COMPANY ("SHIPPER"), dated May 1, 2003, is for all purposes made a part of said Agreement.

"SHIPPER":

Notices:
Manager - Operations, Dispatch & Fuels
OKLAHOMA GAS & ELECTRIC COMPANY
P.O. Box 321, M/C GB58
Oklahoma City, OK 73101-0321
Telephone No.: (405) 553-2778
Facsimile No.: (405) 553-2115

Scheduling and Nominations:
ATTN: Gas Supply Representative
Telephone No.: (405) 553-2803
Facsimile No.; (405) 553-2115

Invoices/Statements:
ATTN: Operations Accounting (M/C 803)
Telephone No.: (405) 553-3618
Facsimile No.: (405) 553-2115

Payments by Electronic Transfer:
Bank of America
Oklahoma City, OK
ABA #103000017
Account #362070101204295

EXHIBIT "F"
TERMINATED AGREEMENTS

This Exhibit "F" to Intrastate Firm No-Notice, Load Following Transportation and Storage Services Agreement by and between ENOGEX INC. ("TRANSPORTER") and OKLAHOMA GAS & ELECTRIC COMPANY ("SHIPPER"), dated May 1, 2003, is for all purposes made a part of said Agreement.

The following agreements shall be replaced and superseded upon execution of this Agreement by the Parties:

1) Binding Letter Agreement — Intrastate Firm Services, between Enogex Inc. and Oklahoma Gas & Electric Company, dated June 4, 2001; and,

2) Natural Gas Storage Agreement, between Oklahoma Gas & Electric Company and Central Oklahoma Oil and Natural Gas Corporation, dated November 7, 1996, as amended.

3) Natural Gas Storage Operating Agreement between Oklahoma Gas & Electric Company and Central Oklahoma Oil and Natural Gas Corporation, dated July 18, 1998.

EXHIBIT "G"
STORAGE SERVICE

This Exhibit "G" to Intrastate Firm No-Notice, Load Following Transportation and Storage Services Agreement by and between ENOGEX INC. ("TRANSPORTER") and OKLAHOMA GAS & ELECTRIC COMPANY ("SHIPPER"), dated May 1, 2003, is for all purposes made a part of said Agreement.

Inventory * (MMBtu)	Daily Injection Quantity (MMBtu/day)	Daily Withdrawal Quantity (MMBtu/day)	Hourly Injection Quantity (MMBtu/day)	Hourly Withdrawal Quantity NOV. - APR. (MMBtu/day)	Hourly Withdrawal Quantity MAY - OCT. (MMBtu/day)
5,300,001 - 5,800,000	(150,000)	150,000	(220,000)	260,000	260,000
5,800,001 - 6,300,000	(150,000)	160,000	(220,000)	280,000	280,000
6,300,001 - 6,800,000	(150,000)	170,000	(220,000)	280,000	300,000
6,800,001 - 7,300,000	(150,000)	180,000	(220,000)	280,000	320,000

7,300,001 - 7,800,000	(150,000)	190,000	(220,000)	280,000	340,000
7,800,001 - 8,300,000	(150,000)	200,000	(220,000)	280,000	360,000

*** SHIPPER shall maintain an inventory of no less than 5,300,000 MMBtu, and no greater than 8,300,000 MMBtu, unless as authorized by Section 2(a) of this Agreement.**

Exhibit 10.25

Contract No. 21004000A — Revised 11/10/04

Firm Transportation Service Agreement
Rate Schedule FT

between

Cheyenne Plains Gas Pipeline Company, L.L.C.

and

OGE Energy Resources, Inc.

Dated: **April 14, 2004, amended and restated as of: December 1, 2004**

Transportation Service Agreement

Rate Schedule TF-1

The Parties identified below, in consideration of their mutual promises, agree as follows:

1. ***Transporter:*** **CHEYENNE PLAINS GAS PIPELINE COMPANY, L.L.C.**

2. ***Shipper:*** **OGE ENERGY RESOURCES, INC.**

3. ***Applicable Tariff:*** Transporter’s FERC Gas Tariff, Original Volume No. 1, as the same is approved by the FERC subsequent to the issuance of a Certificate of Public Convenience and Necessity for the Cheyenne Plains Pipeline and as it may be amended or superseded from time to time (“the Tariff”).

4. ***Incorporation by Reference:*** This Agreement in all respects shall be subject to the provisions of Rate Schedule FT and to the applicable provisions of the General Terms and Conditions of the Tariff as filed with, and made effective by, the FERC as same may change from time to time.

5. ***Transportation Service:*** Transportation Service at and between Primary Receipt Point(s) and Primary Delivery Point(s) shall be on a firm basis. Receipt and Delivery of quantities at Secondary Receipt Point(s) and/or Secondary Delivery Point(s) shall be in accordance with the Tariff.

6. ***Receipt and Delivery Points:*** Shipper agrees to tender Gas for transportation service and Transporter agrees to accept receipt quantities at the Primary Receipt Point(s) identified in Exhibit “A.” Transporter agrees to provide transportation service and deliver gas to Shipper (or for Shipper’s account) at the Primary Delivery Point(s) identified in Exhibit “A.” Minimum and maximum receipt and delivery pressures, as applicable, are listed on Exhibit “A.”

7. ***Rates and Surcharges:*** As set forth in Exhibit “B.” Shipper shall pay the applicable maximum tariff rate unless otherwise provided. Transporter and Shipper may mutually agree to a discounted rate pursuant to the rate provisions of Rate Schedule FT.

8. ***Negotiated Rate Agreement****:* Yes _X_ No___

9. ***Term of Agreement:***

Beginning:	The first day the Pipeline is ready to free flow gas.
Extending through:	10 years, 2 months from the first day of the month following the date the Pipeline is fully operational (the "In-Service Date")

10. ***Effect on prior Agreement:*** When this Agreement becomes effective, it shall amend and restate the following agreement between the Parties: The Firm Transportation Service Agreement between Transporter and Shipper dated September 1, 2004, referred to as Transporter's Agreement No. 21004000.

11. ***Maximum Daily Quantity (MDQ):***

MDQ (Dth/d)	Effective
41,786	The first day the Pipeline is ready to free flow gas
60,000	The first day of the month following the date the Cheyenne Plains Pipeline is fully operational (the "In-Service Date")

12. ***Notices, Statements, and Bills:***

To Shipper:

Invoices for Transportation:
OGE Energy Resources, Inc.
515 Central Park Drive, Suite 408
Oklahoma City, Oklahoma 73105
Attention: Gas Accounting

All Notices:
OGE Energy Resources, Inc.
515 Central Park Drive, Suite 408
Oklahoma City, Oklahoma 73105
Attention: Vice President

To Transporter:
See Payments, Notices, and Contacts sheet in the Tariff.

13. ***Changes in Rates and Terms:*** Transporter shall have the right to propose to the FERC changes in its rates and terms of service, and this Agreement shall be deemed to include any changes which are made effective pursuant to FERC Order or regulation or provisions of law, without prejudice to Shipper's right to protest the same.

14. ***Governing Law***. Transporter and Shipper expressly agree that the laws of the State of Colorado shall govern the validity, construction, interpretation, and effect of this

Agreement and of the applicable Tariff provisions. This Agreement is subject to all applicable rules, regulations, or orders issued by any court or regulatory agency with proper jurisdiction.

15. ***Construction of Facilities***. The parties recognize that Transporter must construct additional facilities in order to provide transportation service for Shipper under this Agreement. Transporter's obligations under this Agreement are subject to: (i) the receipt and acceptance by Transporter of a FERC certificate for the additional facilities, as well as the receipt by Transporter of all other necessary regulatory approvals, permits, and other authorizations for the additional facilities in form and substance satisfactory to Transporter in its sole discretion; (ii) the approval of the appropriate management, management committee, and/or board of directors of Transporter and/or its parent companies to approve the level of expenditures for the additional facilities; and (iii) Shipper shall provide evidence of creditworthiness in a manner satisfactory to Transporter equal to at least one year of Shipper's reservation and commodity charges under the Agreement (satisfactory evidence of creditworthiness may include a Letter of Credit, a guarantee from a creditworthy party, or a satisfactory review of the financial status of the Shipper by Transporter). The one-year requirement shall remain in effect until Transporter has been reimbursed for the cost of the facilities or this Agreement terminates, whichever occurs sooner. Transporter shall construct a 36-inch pipeline capable of transporting 560 MDth per day and shall make good faith efforts to achieve an in-service date by August 31, 2005, subject to timely receipt by Transporter of the FERC Certificate and all other necessary permits and authorization for the construction and operation of the Cheyenne Plains Pipeline. If the In-Service Date referenced above has not occurred by August 31, 2005, and Cheyenne Plains is not proceeding with reasonable diligence towards an In-Service Date at that time, Shipper shall be relieved of its obligations hereunder by providing notice as provided herein.

16. ***Sharing of Interruptible and Short Term Firm Transportation Revenue and Authorized Overrun Charges.*** Under this negotiated rate agreement, Shipper shall receive fifty percent (50%) of a pro rata share of the revenues received by Transporter from Interruptible and Short-Term Firm Transportation Services (net of variable costs and surcharges) until such time as the FERC modifies the treatment of the costs and revenues of such service. In addition, Shipper shall receive fifty percent (50%) of a pro rata share of any Authorized Overrun charges collected by Transporter (net of variable costs and surcharges) until such time as the FERC modifies the treatment of Authorized Overrun Charges. Shipper's pro rata share shall be determined and paid annually and shall be based upon the relationship of the total payments received by Transporter from the Shipper and the total revenues received by the Transporter.

17. ***Most-favored Nations Rate Provision.*** From October 18, 2002 through the term of this Agreement, if a future shipper on an expansion of the Pipeline executes a transportation service agreement for service from the Cheyenne to the Greensburg area for the same length of service or shorter that has a negotiated or discounted rate that is lower on a 100 percent load factor basis than the negotiated rate contained herein, then the rate established in this Agreement shall be reduced to the same level as such other comparable negotiated or discounted rate. Rates for

services using capacity release, discounts granted to Secondary Points, or rates resulting from the exercise of a ROFR right will not trigger this most favored nation provision.

18. ***Execution of Replacement Agreement.*** In the event the Pro Forma Transportation Service Agreement approved by the FERC as part of the Tariff of the Cheyenne Plains Pipeline varies in form from this Agreement, the Parties agree to execute a replacement agreement in the form of the pro forma agreement in the Tariff. Any substantive difference between this Agreement and the approved pro forma agreement, which remains in effect at the time the replacement agreement is prepared shall be reflected in the replacement agreement.

19. ***Assignment:*** Prior to the earlier of the In-Service Date of the Cheyenne Plains Pipeline, or August 31, 2005, neither party may assign its rights or obligations under this Agreement without the written consent of the other party, which consent shall not be unreasonably withheld.

IN WITNESS WHEREOF, the parties hereto have executed this Agreement.

Transporter:

CHEYENNE PLAINS GAS PIPELINE COMPANY, L.L.C.

By: /s/ Thomas L. Price
Thomas L. Price
Vice President

Accepted and agreed to this
15th day of November, 2004

Shipper:

OGE ENERGY RESOURCES, INC.

By: /s/ G. Rankin Schurman

Name: G. Rankin Schurman

Title: Vice President

Accepted and agreed to this
19th day of November, 2004

Exhibit "A"

Firm Transportation Service Agreement
between
Cheyenne Plains Gas Pipeline Company, L.L.C.
and
OGE Energy Resources, Inc.

Dated: **April 14, 2004, amended and restated as of: December 1, 2004**

1. Shipper's Maximum Delivery Quantity ("MDQ"): On the first day the Pipeline is ready to free flow gas (*i.e.*, before the amine plant and compression facilities are fully operational) the Shipper's MDQ shall be equal to **41,786** Dth per Day (Shipper's pro rata share (based on full MDQ) of the available free-flow capacity of the Cheyenne Plains Pipeline). Commencing upon the first day of the month following the date the Cheyenne Plains Pipeline is fully operational Shipper's MDQ shall be **60,000** Dth per Day

Primary Receipt Point(s) (Note 1)	*Effective Dates*	*Primary Receipt Point(s) Quantity (Dth per Day) (Note 2)*	*Minimum Pressure (p.s.i.g.)*	*Maximum Pressure (p.s.i.g.)*
Curley	On the first day the pipeline is ready to free flow gas	10,446	920	1,000
Thunder Chief	On the first day the pipeline is ready to free flow gas	31,340	920	1,000
Curley	The first day of the month following the date the Cheyenne Plains Pipeline is fully operational	15,000	920	1,000
Thunder Chief	The first day of the month following the date the Cheyenne	45,000	920	1,000

	Plains Pipeline is fully operational			

Exhibit "A"

Primary Delivery Point(s) (Notes 1 and 4)	*Effective Dates*	*Primary Delivery Point(s) Quantity (Dth per Day) (Note 3)*	*Minimum Pressure (p.s.i.g.)*	*Minimum Pressure (p.s.i.g.)*
Greensburg	On the first day the pipeline is ready to free flow gas	20,893	LP	Not to exceed 880
South Rattlesnake Creek	On the first day the pipeline is ready to free flow gas	20,893	LP	Not to exceed 880
Greensburg	The first day of the month following the date the Cheyenne Plains Pipeline is fully operational	50,000	LP	Not to exceed 880
South Rattlesnake Creek	The first day of the month following the date the Cheyenne Plains Pipeline is fully operational	10,000	LP	Not to exceed 880

NOTES:

(1) Information regarding receipt point(s) and delivery point(s), including legal descriptions, measuring Parties, and interconnecting Parties, shall be posted on Transporter's Electronic Bulletin Board. Transporter shall update such information from time to time to include additions, deletions, or any other revisions deemed appropriate by Transporter.

(2) Each receipt point quantity may be increased by an amount equal to Transporter's Fuel Reimbursement percentage. Shipper shall be responsible for providing such Fuel Reimbursement at each receipt point on a pro rata basis based on the quantities received on any Day at a receipt point divided by the total quantity delivered at all delivery point(s) under this Transportation Service Agreement.

(3) The sum of the delivery quantities at delivery point(s) shall be equal to Shipper's MDQ.

(4) Cheyenne Plains shall install delivery facilities to Southern Star with meter capacities capable of flowing 560 MDth provided the delivery pressure equals or exceeds 810 p.s.i.g. (recognizing that the current take-away capacity at the proposed point of interconnection with Southern Star is approximately 400 MDth per Day). Cheyenne Plains shall install delivery facilities to ANR, PEPL, NNG and NGPL with meter capacities capable of flowing the lesser of (i) the maximum deliverability of the Cheyenne Plains pipeline at the point of interconnection, or (ii) the current take-away capacity at the point of interconnection, or (iii) 1000 MDth (provided the delivery pressure equals or exceeds 810 p.s.i.g.).

Exhibit “B”

Firm Transportation Service Agreement
between
Cheyenne Plains Gas Pipeline Company, LLC
and
OGE Energy Resources, Inc.

Dated: **April 14, 2004, amended and restated as of: December 1, 2004**

Primary Receipt Point(s)	*Primary Delivery Point(s)*	*Reservation Rate*	*Commodity Rate*	Term of Rate	*Fuel Reimbursement*	*Surcharges*
As listed on Exhibit "A"	As listed on Exhibit "A"	$0.00	$0.10/Dth	Commencing upon the first day the Pipeline is ready to free flow gas until the first day of the month following the date the Pipeline is fully operational	(Note 2)	(Note 3)
As listed on Exhibit "A"	As listed on Exhibit "A"	(Note 1)	(Note 1)	Commencing upon the first day of the month following the date the Cheyenne Plains Pipeline is fully operational and continuing for a term of ten (10) years, 2 months	(Note 2)	(Note 3)

Secondary Receipt Point(s)	*Secondary Delivery Point(s)*	*Reservation Rate*	*Commodity Rate*	*Term of Rate*	*Fuel Reimbursement*	*Surcharges*
All	All	$0.00	$0.10/Dth	Commencing upon the first day the Pipeline is ready to free flow gas until the first day of the month following the date the Pipeline is fully operational	(Note 2)	(Note 3)

Exhibit “B”

Secondary Receipt Point(s)	*Secondary Delivery Point(s)*	*Reservation Rate*	*Commodity Rate*	*Term of Rate*	*Fuel Reimbursement*	*Surcharges*
All	All	(Note 1)	(Note 1)	Commencing upon the first day the month following the date the Cheyenne Plains Pipeline is fully	(Note 2)	(Note 3)

operational and
continuing for a
term of ten (10)
years, 2 months

NOTES:

(1) Shipper shall pay negotiated reservation rates of $10.3417 per month. (The monthly reservation charge is equivalent to a rate of $0.34 per Dth per day on a 100% load factor basis.) Under the negotiated rates, there will be no commodity or usage charge, unless Transporter is required by the FERC to assess such a commodity charge, in which event the commodity charge shall be set at the minimum permissible level, and the reservation rate described above shall be reduced to a level that causes the combined commodity and reservation rates to equal a 100% load factor rate of $0.34. Should the FERC or a court with jurisdiction issue a ruling that has the effect of prohibiting Transporter from collecting, or penalizing Transporter for collecting the rates and revenues provided for herein, then the parties agree to enter into a substitute lawful arrangement, such that the parties are placed in the same economic position as if Transporter had collected such rates. The negotiated rate shall be applicable to revised primary receipt or delivery points, and Transporter shall agree to all requests for changes to primary receipt or delivery point changes if capacity is available at such points and the change can be made without adversely affecting system operations or other firm obligations.

(2) From the first day the Pipeline is ready to free flow gas until the first day of the month following the date the Pipeline is fully operational, no fuel will be consumed in pipeline operations. Accordingly, during such period the fuel reimbursement shall be limited to a collection of lost and unaccounted for gas. Following the first day of the month following the date the Cheyenne Plains Pipeline is fully operational Fuel Reimbursement shall be as stated on Transporter's Statement of Rates sheet in the Tariff, as they may be changed from time to time, unless otherwise agreed between the Parties.

(3) Surcharges, if applicable: All applicable surcharges, unless otherwise specified, shall be the maximum surcharge rate as stated on the Statement of Rates sheet, as they may be changed from time to time, unless otherwise agreed to by the Parties.

Exhibit 10.26

AMENDMENT NO. 5
TO THE OGE ENERGY CORP.
RESTORATION OF RETIREMENT INCOME PLAN
(As Amended and Restated Effective January 1, 1994)

OGE Energy Corp., an Oklahoma corporation (the "Company"), in accordance with the authority reserved to the Company under Section 9 of the OGE Energy Corp. Restoration of Retirement Income Plan (As Amended and Restated Effective January 1, 1994), as heretofore amended (the "Plan"), hereby amends the Plan, effective as of December 31, 2004, in the following respect:

1. By adding a new paragraph at the end of Section 5 of the Plan as follows:

"Notwithstanding the foregoing provisions of this Section 5 or any other provision of this Plan, benefits shall cease to accrue under this Plan as of December 31, 2004 and the benefits payable under this Plan to any participant who terminates employment with the Company or other Employer after December 31, 2004 or his beneficiary or beneficiaries, as computed in accordance with the foregoing provisions of this Section 5, shall be limited to and shall not exceed the amount that is payable to the recipient with respect to the amounts determined by the Retirement Committee to have been deferred under the Plan by the participant before January 1, 2005 within the meaning of Section 885(d) of the American Jobs Creation Act of 2004 and the regulations and guidance issued thereunder with respect to Section 409A of the Code (the "Grandfathered Benefit"), and employees employed by the Company or other Employer on or after January 1, 2005 who are not entitled to a Grandfathered Benefit as a result of the foregoing limitation (or their beneficiary or beneficiaries) shall not be entitled to any benefits under this Plan."

IN WITNESS WHEREOF, OGE Energy Corp. has caused this instrument to be executed in its name by its duly authorized officer as of the 31st day of December, 2004.

OGE Energy Corp.

By: /s/ Peter B. Delaney

Title: Executive Vice President and

Chief Operating Officer

Exhibit 10.27

OGE ENERGY CORP.
DIRECTORS' COMPENSATION

For 2005, compensation of non-officer directors of the Company will consist of an annual retainer fee of $66,000, of which $24,000 will be payable monthly in cash and $42,000 will be deposited in the director's account under the deferred compensation plan. The chairman of the audit committee will receive an additional annual retainer of $10,000, the chairman of the compensation committee and nominating and corporate governance committees will each receive additional annual retainers of $5,000 and the lead director will receive an additional annual retainer of $10,000. All non-officer directors will receive a fee of $1,200 for each board and committee meeting attended.

Under the Directors' Deferred Compensation Plan (the "Plan"), non-officer directors may defer payment of all or part of their attendance fees and the cash portion of their annual retainer fee, which deferred amounts are credited to their account on the date the deferred amounts otherwise would have been paid.

Amounts credited to the accounts are assumed to be invested in one or more of the investment options permitted under the Plan. During 2004, those investment options included a Company Common Stock fund, whose value was determined based on the stock price of the Company's Common Stock, a money market fund, a bond fund and several stock funds.

When an individual ceases to be a director of the Company, all amounts credited under the Plan are paid in cash in a lump sum or installments.

Historically, for those directors who retired from the Board of Directors after 10 years or more of service, the Company and OG&E continued to pay their annual cash retainer until their death. In November 1997, the Board eliminated this retirement policy for directors. Directors who retired prior to 1997, however, will continue to receive benefits under the former policy.

Exhibit 10.28

OGE ENERGY CORP.
EXECUTIVE OFFICER COMPENSATION

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

Salary

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

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

Annual Incentive Awards

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

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

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

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

Long-Term Awards

For 2005, the Committee made awards of performance units. The number of performance units granted was determined by taking the amount of the executive's long-term award to be delivered in performance units (adjusted on a present value basis), as determined by the Committee, and dividing that amount by the closing price for the Company's Common Stock on January 3, 2005 with a vesting factor applied. This resulted in executives receiving performance units with an expected value at the date of grant of from 25% to 150% of their 2005 base salaries. The value of the performance units is substantially dependent upon the changing value of the Company's Common Stock in the marketplace. Each executive officer is entitled to receive from 0% to 200% of the performance units contingently awarded to the executive depending upon corporate performance. For 75% of the performance units, this corporate performance will be based on the Company's total shareholder return over a three-year period (defined as share price increase plus dividends paid, divided by share price at beginning of the period) measured against the total shareholder return for such period by a peer group selected by the Committee. For the remaining 25% of the performance units, the corporate performance will be based upon the growth in the Company's earnings per share compared to specified targets selected by the Committee.

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

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

Other Benefits

Virtually all of our employees, including executive officers, are eligible to participate in the Retirement Savings Plan and pension plan. Both the Retirement Savings Plan and pension plan have supplemental restoration plans that enable executive officers to receive the same benefits that they would have received in the absence of limitations imposed by the federal tax

laws on contributions or payouts. In addition, a Supplemental Executive Retirement Plan (the "SERP"), which was adopted in 1993, offers attractive pension benefits to lateral hires. No officer, other than Mr. Delaney, participated in the SERP during 2004. The SERP is not expected to benefit other existing executive officers generally who remain employed by the Company or OG&E until age 65. The restoration plans for the Retirement Savings Plan and pension plan contain provisions requiring their immediate funding in the event of certain mergers, consolidations or tender offers involving the Company.

The executive officers also receive certain personal benefits, including reimbursement for tax and estate planning and club memberships. The value of these personal benefits is less than $50,000 for each of the named executive officers other than Mr. Moore. Mr. Moore utilized the services of a corporate-leased aircraft for travel to and from a medical institution for treatment. The use of the aircraft for this purpose was approved by the Compensation Committee. Mr. Moore reimbursed the Company for the amount that would have been included in his income under applicable Internal Revenue Code regulations, which amount for 2004 was approximately $2,102.44 less than the out-of-pocket expenses to the Company.

The Company and OG&E also have entered into employment agreements with each officer of the Company and OG&E. Under the agreements, the officer is to remain an employee for a three-year period following a change of control of the Company (the "Employment Period"). During the Employment Period, the officer is entitled to (i) an annual base salary in an amount at least equal to his or her base salary prior to the change of control, (ii) an annual bonus in an amount at least equal to his or her highest bonus in the three years prior to the change of control and (iii) continued participation in the incentive, savings, retirement and welfare benefit plans. The officer also is entitled to payment of expenses and provision of fringe benefits to the extent paid or provided to (a) such officer prior to the change of control or (b) other peer executives of the Company.

If, during the Employment Period, the officer's employment is terminated by the employer for reasons other than cause or disability or by such officer due to a change in employment responsibilities, the officer is entitled to the following payments: (i) all accrued and unpaid compensation and (ii) a severance payment equal to 2.99 times the sum of such officer's (a) annual base salary and (b) highest recent annual bonus. The officer also is entitled to continued welfare benefits for three years and outplacement services. If the payment of the foregoing benefits, when taken together with any other payments to the officer, would result in the imposition of the excise tax on excess parachute payments under Section 4999 of the Internal Revenue Code of 1986, as amended, then the severance benefits will be reduced if such reduction results in a greater after-tax payment to the officer. The officer is entitled to receive such amounts in a lump-sum payment within 30 days of termination. A change of control encompasses certain mergers and acquisitions, changes in Board membership and acquisition of securities of the Company.

The form of Change of Control Agreement is filed as Exhibit 10.01 to this Form 10-K.

Exhibit 10.29

OGE ENERGY CORP.
FORM OF NON-QUALIFIED STOCK OPTION AGREEMENT
UNDER 2003 STOCK INCENTIVE PLAN

(pursuant to the OGE Energy Corp. Incentive Stock Plan)

AGREEMENT executed as of ______, by and between OGE Energy Corp., an Oklahoma corporation (the "Company"), and (name) ("the Participant").

WITNESSETH:

WHEREAS, on January 21, 1998, the Board of Directors of the Company (the "Board") established the OGE Energy Corp. Incentive Stock Plan (the "Plan"); and

WHEREAS, the committee appointed by the Board to administer the Plan (the "Committee") has determined that the Participant is eligible under the Plan and that it is to the advantage and interest of the Company to grant the option provided for herein (the "Option") to the Participant as an incentive for Participant's increased efforts on behalf of the Company; and

NOW THEREFORE,

1. **Grant of Option**. The Company hereby grants to the Participant an option to purchase an aggregate of (___) shares of the Company's common stock, par value $0.1 per share (the "Common Stock"), at the price of $______ per share (being not less than the Fair Market Value (as defined in Section 1(p) of the Plan) of the Common Stock on the date the Option is granted) upon the terms and conditions hereinafter set forth and as set forth in the Plan.

2. **Period of Option**. The Option shall expire at 5:00 p.m. Central Time, on _______, unless it sooner terminates as provided in paragraph 5 hereof.

3. **Who May Exercise**. The Option may be exercised solely by the Participant, except as provided in paragraph 11 hereof. The Option and any rights and privileges pertaining thereto shall not be transferred, other than in accordance with paragraph 11 hereof and may not be assigned, pledged or hypothecated by the holder thereof in any way, whether by operation of law or otherwise, and shall not be subject to execution, attachment or similar process.

4. **Exercise of Option**.

(a) Except to the extent otherwise provided in this Agreement and the Plan, the Option is not immediately exercisable and will become exercisable in three annual installments as follows:

The Option may be exercised as to _(1/3 #)_shares after ________.

The Option may be exercised as to _(1/3 #)_shares after _______.

The Option may be exercised as to _(1/3 #)_shares after _______.

(b) The Option, or any part of it, shall be exercised by written notice directed to the Secretary of the Company. Such notice must satisfy the following requirements:

(i) The notice must state the date of grant, the number of shares of Common Stock subject to the grant, the number of shares of Common Stock with respect to which the Option is being exercised, the person in whose name the stock certificate or certificates for such shares of Common Stock is to be registered and the person's address and Social Security number (or if more than one person, the names, addresses and Social Security numbers of such persons).

(ii) The notice shall be accompanied by full payment of the exercise price for the number of shares specified in the notice, in the form of a check, bank draft, money order or other cash payment or by delivery of a certificate or certificates acceptable to the Committee, properly endorsed, for shares of Common Stock equivalent in Fair Market Value (as defined in Section 1(p) of the Plan) on the date of exercise to such exercise price, or by a combination of cash and shares.

(iii) The notice shall contain such representations and agreements as to the holder's investment intent with respect to such shares of Common Stock as may be satisfactory to the Committee.

(iv) The notice must be signed by the person or persons entitled to exercise the Option and, if the Option is being exercised by any person or persons other than the Participant, be accompanied by proof, satisfactory to the Committee, of the right of such person or persons to exercise the Option.

If permitted by applicable law, the payment of the option price may also be made by delivering a properly executed exercise notice to the Company, together with a copy of irrevocable instructions to a broker to deliver promptly to the Company the amount of sale or loan proceeds to pay the option price, and, if requested by the Company, the amount of any federal, state, local or foreign withholding taxes.

The exercise may be with respect to any one or more shares of Common Stock covered by the Option (to the extent then exercisable), reserving the remainder for a subsequent timely exercise. The Company shall make prompt delivery of such shares; provided that, if any law or regulation requires the Company to delay, or to take any action with respect to such shares before, the issuance thereof, then the date of delivery of such shares shall be extended for the period necessary until such requirement is met; and provided further that the Company shall have no obligation to deliver any such certificate unless and until appropriate provision has been made for any withholding taxes in respect of such exercise. The Participant may elect to surrender shares of Common Stock previously acquired by him/her or to have the Company withhold

shares that would have otherwise been issued pursuant to the exercise of the Option in order to satisfy all or a portion of any such tax withholding obligation.

5. **Exercise in the Event of Death, Disability, Retirement or Other Termination**.

(a) *Termination of Employment By Death*. Unless otherwise determined by the Committee, if Participant's employment is terminated by reason of death, the Option will become immediately exercisable and may thereafter be exercised by the holder for a period of one year from the date of death or until the expiration of the stated term of the Option, whichever period is shorter.

(b) *Termination of Employment By Reason of Disability*. Unless otherwise determined by the Committee, if Participant's employment is terminated by reason of Disability (as defined in Section 1(1) of the Plan), the Option will become immediately exercisable and may thereafter be exercised by the Participant for a period of three years from the date of such termination or until the expiration of the stated term of the Option, whichever period is shorter; *provided, however*, that if the Participant dies within such three-year period and prior to the expiration of the stated term of the Option, any unexercised portion of the

Option shall, notwithstanding the expiration of such three-year period, continue to be exercisable for a period of 12 months from the date of death or until the expiration of the stated term of the Option, whichever period is shorter.

(c) *Termination of Employment By Reason of Retirement*. Unless otherwise determined by the Committee, if Participant's employment is terminated by reason of retirement, on or after the participant reaches age 55, the Option will become immediately exercisable and may thereafter be exercised by Participant for a period of three years from the date of such retirement or until the expiration of the stated term of the Option, whichever period is shorter, *provided, however,* that if the Participant dies within such three-year period and prior to the expiration of the stated term of the Option, any unexercised portion of the Option shall, notwithstanding the expiration of such three-year period, continue to be exercisable for a period of 12 months from the date of death or until the expiration of the stated term of the Option, whichever period is shorter.

(d) *Other Termination of Employment*. Unless otherwise determined by the Committee, if for any reason other than death, retirement after reaching age 55, or Disability, Participant's employment is terminated, the Option shall thereupon terminate, except that the Option, to the extent then exercisable, or on such accelerated basis as the Committee may determine, may be exercised for the lesser of three months from the date of such termination or the balance of the Option's stated term if such termination is involuntary; *provided, however*, that if the Participant dies within such three-month period, any unexercised portion of the Option shall, notwithstanding the expiration of such three-month period, continue to be exercisable to the extent to which it was exercisable at the time of death for a period of 12 months from the date of such death or until the expiration of the stated term of the Option, whichever period is shorter. Notwithstanding the foregoing, if the Participant's employment is terminated at or after a Change of Control (as defined in Section 9(b) of the Plan), other than by reason of death, retirement after reaching age 55, or Disability, the Option shall be exercisable for the lesser of

(1) six months and one day from the date of such termination, or (2) the balance of the Option's stated term.

6. **Change of Control.**

In the event of a Change of Control (as defined in Section 9(b) of the Plan), the Option shall become fully exercisable and vested. In addition, during the 60-day period from and after the Change of Control (as defined in Section 9(b) of the Plan), subject to Section 13(i) of the Plan, the Participant has the right, whether or not the Option is fully exercisable and in lieu of the payment of the option price for the shares being purchased under the Option and by giving notice to the Company, to elect (within such 60-day period) to surrender all or part of the Option to the Company and to receive cash, within 30 days of such notice, in an amount equal to the amount by which the Change of Control Price (as defined in Section 9(c) of the Plan) per share on the date of such election shall exceed the option price per share under the Option multiplied by the number of shares under the Option as to which this right is being exercised.

7. **Adjustment Provisions.**

In the event of any change in corporate capitalization, such as a stock split, or a corporate transaction, such as any merger, consolidation, share exchange, separation, including a spin-off, or other distribution of stock or property of the Company, any reorganization (whether or not such reorganization comes within the definition of such term in Section 368 of the Internal Revenue Code of 1986, as amended) or any partial or complete liquidation of the Company, the Committee shall adjust equitably (i) the number and class of shares or other securities that are subject to the Option and (ii) the exercise price and other price determinations applicable to the Option. All determinations with respect to such adjustments shall be made by the Committee and, when made by the Committee, shall be conclusive and binding.

8. **No Rights in Stock**. The holder of the Option shall have no rights as a shareowner in respect of any shares unless and until a certificate or certificates representing such shares shall have been delivered to him.

9. **Effect Upon Employment**. Neither the granting of the Option nor any term or provision hereof shall constitute or be evidence of any understanding, express or implied, on the part of the Company or any of its subsidiaries to employ or continue to employ the Participant for any period.

10. **Restrictions on Exercise**. Notwithstanding any other provision of the Plan or this Agreement, the Company shall not be required to issue or deliver any certificate or certificates for shares of Common Stock under the Option prior to fulfillment of all of the following conditions:

(a) The listing or approval for listing upon notice of issuance, of such shares on the New York Stock Exchange, Inc., or such other securities exchange as may at the time be the principal market for the Common Stock;

(b) Any registration or other qualification of such shares of the Company under any state or Federal law or regulation, or the maintaining in effect of any such registration or other qualification which the Committee shall, in its absolute discretion upon the advice of counsel, deem necessary or advisable; and

(c) The obtaining of any other consent, approval, or permit from any state or Federal governmental agency which the Committee shall, in its absolute discretion after receiving the advice of counsel, determine to be necessary or advisable.

11. **Transferability**. (a) The Option shall not be transferable by the Participant other than (i) by will or by the laws of descent and distribution or (ii) pursuant to a gift to Participant's children, whether directly or indirectly or by means of a trust or partnership or otherwise. The Option shall be exercisable, during the Participant's lifetime, only by the Participant or by the guardian or legal representative of the Participant.

(b) Following any such permitted transfer, the Option shall continue to be subject to the terms and conditions of this Agreement, including those specified in paragraph 4 herein, as were applicable immediately prior to the transfer. The treatment of the Option upon termination set forth in paragraph 5 herein shall continue to be applied with respect to the Participant, following which the Option shall be exercisable by the transferee only to the extent, and for the periods specified in paragraph 5.

(c) Prior to transferring all or any portion of the Option, the Participant shall notify the Company in writing of the name, address and relationship to the Participant of the intended transferee.

12. **Notices**. All notices to the Company shall be addressed to OGE Energy Corp., 321 N. Harvey, Oklahoma City, Oklahoma 73102, to the attention of the Secretary, and all notices to the Participant shall be addressed to him at his address shown at that time on the payroll records of the Company or of a subsidiary, or to such other address as either may designate to the other in writing. Notice may be delivered in person or by mail.

13. **<u>Headings</u>**. Headings are set forth in this instrument solely for convenience of reference and shall have no bearing upon its interpretation or construction.

14. **<u>Option Subject to Terms of Plan</u>**. The granting of the Option is being made pursuant to the Plan and the Option shall be exercisable only in accordance with the applicable terms of the Plan. The Plan contains certain definitions, restrictions, limitations and other terms and conditions all of which shall be applicable to the Option. **ALL THE PROVISIONS OF THE PLAN ARE INCORPORATED HEREIN BY REFERENCE AND ARE MADE A PART OF THIS AGREEMENT IN THE SAME MANNER AS IF EACH AND EVERY SUCH PROVISION WERE FULLY WRITTEN INTO THIS AGREEMENT.** Should the Plan become void or unenforceable by operation of law or judicial decision, this Agreement shall have no force or effect. Nothing set forth in this Agreement is intended, nor shall any of its provisions be construed, to limit or exclude any definition, restriction, limitation or other term or condition of the Plan as is relevant to this Agreement and as may be specifically applied to it by

the Committee. In the event of a conflict in the provisions of this Agreement and the Plan, as a rule of construction, the terms of the Plan shall be deemed superior and apply. The Participant acknowledges receipt of a copy of the Plan.

15. **<u>Severability.</u>** If any provision or portion of this Agreement shall be determined to be invalid or enforceable for any reason, the remaining provisions of this Agreement shall be unaffected and shall remain in full force and effect in such jurisdiction, and any such invalid or unenforceable provision shall not be considered invalid or unenforceable in any other jurisdiction.

IN WITNESS WHEREOF, the Company has caused these presents to be signed by its duly authorized officer and its corporate seal to be hereunto affixed and the Participant has hereunto set his hand on the day and year first above written.

OGE ENERGY CORP.

By ______________________________

Its Chairman of the Board, President
And Chief Executive Officer

Attest:

____

Its Secretary

____

Participant's Signature

____

Printed or typed name

____

Street Address

____

City, State, Zip Code

____

Social Security Number

____

Telephone Number

Exhibit 10.30

OGE ENERGY CORP.
FORM OF PERFORMANCE UNIT AGREEMENT
UNDER 2003 STOCK INCENTIVE PLAN

OGE Energy Corp. (the "Company") hereby awards, at target, to (____) (the "Participant") (#) Performance Units pursuant to the 2003 OGE Energy Corp. Stock Incentive Plan (the "Plan"), the definitions and provisions of which are incorporated herein by reference.

The specific terms and conditions of the award are set forth hereinafter.

1. Performance Units and Award Cycle. Each Performance Unit represents and is equal to the value of one share of Company Common Stock. Subject to the provisions of the Plan, the Performance Units awarded to the Participant may not be sold, assigned, transferred, pledged, hypothecated or otherwise encumbered or disposed of during the award cycle established with respect thereto beginning on _____ and ending on _____ (the "Award Cycle").

2. Performance Goal Condition. The Performance Units are contingently awarded subject to the condition that the number of Performance Units, if any, earned by the Participant upon the expiration of the Award Cycle is dependent (in the manner hereinafter set forth) on the Company's total shareholder return ("TSR") relative to the TSR of (or their successors from a merger or other combination with another company listed on the attached Exhibit A). TSR for any company, including the Company, shall include both price appreciation (depreciation) and cash dividends and shall be measured by the company's total return that shareholders receive over the Award Cycle by investment at the first day of the Award Cycle.

The number of Performance Units earned is dependent on the performance ranking of the Company's TSR for the Award Cycle, as set forth below (expressed in terms of the Company's position in the ______ Index when ranked by TSR for the Award Cycle):

COMPANY TSR PERCENTILE RANKING VS. S&P UTILITY INDEX	PERCENT OF TARGET PERFORMANCE UNITS EARNED
___th percentile	200%
___th percentile	175%
___th percentile	150%
___th percentile	125%
___th percentile	100%
___th percentile	75%
___th percentile	50%
___th percentile	25%
Below ___th percentile	0%

Performance Units earned for performance between the percentiles shown above will be determined by straight-line interpolation; provided, that, in all cases, the number of Performance Units which the Participant earns shall be a whole number (disregarding any fraction).

Any Performance Units awarded hereunder that the Participant does not earn at the end of the Award Cycle pursuant to the foregoing schedule shall be forfeited.

The provisions of this Section 2 shall not affect in any way any forfeiture under Section 4 below or Section 8 (b) of the plan or any provision regarding the earning of Performance Units at the 100% target level under Section 9 of the Plan upon the occurrence of a Change of Control.

3. Payout.

Subject to Section 9 of the Plan, as soon as practicable following the end of the Award Cycle, the Committee shall determine and certify to the number of Performance Units earned hereunder and, after the Committee certifies in writing the number of Performance Units earned, earned Performance Units, if any, will be paid to the Participant or, on the Participant's death, to the Participant's beneficiary under the Plan as follows:

Two-thirds of the earned Performance Units will be paid by issuing a certificate for shares of Common Stock equal in number to two-thirds of the earned Performance Units (disregarding any fraction); and

one-third of the earned Performance Units will be paid in cash in an amount equal to one-third of the earned Performance Units multiplied by the Fair Market Value of one share of Common Stock on ______ (or, if there are no sales of Common Stock on such date, on the next preceding trading date during which a sale occurred).

4. Forfeiture. All Performance Unit awards are subject to the terms and conditions of the Plan relating to Performance Units. If the Participant incurs a Termination of Employment for any reason on or before the end of the Award Cycle, all rights to or in respect of Performance Units awarded hereunder shall be forfeited except (a) as provided in Section 8(b)(iii) or 9(a)(iii) of the Plan.

5. Acceptance of Award. By execution of this Agreement, the Participant accepts the award, acknowledges receipt of a copy of the Plan, and represents that the Participant is familiar with the terms and provisions thereof and agrees to be bound thereby. Participant further agrees to accept as binding, conclusive and final all decisions or interpretations of the Committee with respect to any questions arising under the Plan, including any calculation of, or in connection with, the total shareholder return of the Company or any other company for the Award Cycle.

6. Taxes and Other Matter.

By execution of this Agreement, the Participant agrees that all withholding and other taxes payable with respect to Performance Units earned under this Agreement shall be

payable first from cash payments to be made hereunder and any remainder shall be payable by the Participant at such times and in such manner as the Company may request, and the Participant further agrees to comply with all Federal and State securities laws.

The Participant may elect, subject to approval of the Board of Directors or a committee composed of two or more non-employee directors within the meaning of Rule 16b-3(b)(3) of the Securities Exchange Act of 1934 or any successor provision thereto, to satisfy Participant's tax withholding requirements, in whole or in part, in excess of cash payments to be made hereunder by having the Company withhold shares having a fair market value equal to all or a portion of such amount required to be withheld. The value of the shares to be withheld is to be based upon the same price of the shares that is utilized to determine the amount of withholding tax that the Participant owes. All elections under this Section 6(b) shall be (i) irrevocable, (ii) made in writing and signed by the Participant on the form prescribed by the Company and (iii) submitted to the Board of Directors prior to the November Board of Directors meeting that immediately precedes the date the Award Cycle expires.

7. Other Condition. The award of Performance Units evidenced by this Agreement shall be subject to delivery to the Company of an executed copy of this Agreement.

OGE ENERGY CORP.

By: ____

Chairman of the Board, President
And Chief Executive Officer

ACCEPTED AND AGREED TO this _____ day of _____.

____

Participant

OGE ENERGY CORP.
PERFORMANCE UNIT AGREEMENT

OGE Energy Corp. (the "Company") hereby awards, at target, to _______________ (the "Participant") ____ Performance Units pursuant to the 2003 OGE Energy Corp. Stock Incentive Plan (the "Plan"), the definitions and provisions of which are incorporated herein by reference.

The specific terms and conditions of the award are set forth hereinafter.

1. Performance Units and Award Cycle. Each Performance Unit represents and is equal to the value of one share of Company Common Stock. Subject to the provisions of the Plan, the Performance Units awarded to the Participant may not be sold, assigned, transferred, pledged, hypothecated or otherwise encumbered or disposed of during the award cycle established with respect thereto beginning on _____ and ending on _____ (the "Award Cycle").

2. Performance Goal Condition. The Performance Units are contingently awarded subject to the condition that the number of Performance Units, if any, earned by the Participant upon the expiration of the Award Cycle is dependent (in the manner hereinafter set forth) on the company's Average Earnings Per Share Growth during the Award Cycle. For purposes of the foregoing, all percentages shall be calculated to the nearest one-

hundredth of one percent and the Company's earnings per share for any year shall be the consolidated earnings per average common share of the Company as shown on the Company's Consolidated Statement of Income for such year. The number of Performance Units earned for the Award Cycle shall be determined in accordance with the following chart:

COMPANY'S AVERAGE EARNINGS PER SHARE GROWTH	PERCENT OF TARGET PERFORMANCE UNITS EARNED
%	200%
%	175%
%	150%
%	125%
%	100%
%	75%
%	50%
Below %	0%

Performance Units earned for performance between the percentiles shown above will be determined by straight-line interpolation; provided, that, in all cases, the number of Performance Units which the Participant earns shall be a whole number (disregarding any fraction).

Any Performance Units awarded hereunder that the Participant does not earn at the end of the Award Cycle pursuant to the foregoing chart shall be forfeited.

The provisions of this Section 2 shall not affect in any way any forfeiture under Section 4 below or Section 8(b) of the Plan or any provision regarding the earning of Performance Units at the 100% target level under Section 9 of the Plan upon the occurrence of a Change of Control.

3. Payout.

Subject to Section 9 of the Plan, as soon as practicable following the end of the Award Cycle, the Committee shall determine and certify to the number of Performance Units earned hereunder and, after the Committee certifies in writing the number of Performance Units earned, earned Performance Units, if any, will be paid to the Participant, or on the Participant's death, to the Participant's beneficiary under the Plan as follows:

(a) Two-thirds of the earned Performance Units will be paid by issuing a certificate for shares of Common Stock equal in number to two-thirds of the earned Performance Units (disregarding any fraction); and

(b) one-third of the earned Performance Units will be paid in cash in an amount equal to one-third of the earned Performance Units multiplied by the Fair Market Value of one share of Common Stock on _______ (or, if there are no sales of Common Stock on such date, on the next preceding trading date during which a sale occurred).

4. Forfeiture. All Performance Unit awards are subject to the terms and conditions of the Plan relating to Performance Units. If the Participant incurs a Termination of Employment for any reason on or before the end of the Award Cycle, all rights to or in respect of Performance Units awarded hereunder shall be forfeited except as provided in Section 8(b)(iii) or Section 9(a)(iii) of the Plan.

5. Acceptance of Award. By execution of this Agreement, the Participant accepts the award, acknowledges receipt of a copy of the Plan (a copy of which is attached as Annex I), and represents that the Participant is familiar with the terms and provisions thereof and agrees to be bound thereby. Participant further agrees to accept as binding, conclusive and final all decision or interpretations of the Committee with respect to any questions arising under the Plan, including any calculation of, or in connection with, the total shareholder return of the Company or any other company for the Award Cycle.

6. Taxes and Other Matter.

(a) By execution of this Agreement, the Participant agrees that all withholding and other taxes payable with respect to Performance Units earned under this Agreement shall be payable first from cash payments to be made hereunder and any remainder shall be payable by the Participant at such times and in such manner as the Company may request, and the Participant further agrees to comply with all Federal and State securities laws.

(b) The Participant may elect, subject to approval of the Board of Directors or a committee composed of two or more non-employee directors within the meaning of Rule 16b-3(b)(3) of the Securities Exchange Act of 1934 or any successor provision thereto, to satisfy Participant's tax withholding requirements, in whole or in part, in excess of cash payments to be made hereunder by having the

Company withhold shares having a fair market value equal to all or a portion of such amount required to be withheld. The value of the shares to be withheld is to be based upon the same price of the shares that is utilized to determine the amount of withholding tax that the Participant owes. All elections under this Section 6(b) shall be (i) irrevocable, (ii) made in writing and signed by the Participant on the form prescribed by the Company and (iii) submitted to the Board of Directors prior to the November Board of Directors meeting that immediately precedes the date the Award Cycle expires.

7. Other Condition. The award of Performance Units evidenced by this Agreement shall be subject to delivery to the Company of an executed copy of this Agreement.

OGE ENERGY CORP.

By: ______________________________________

Chairman of the Compensation Committee

ACCEPTED AND AGREED TO this _____ day of _______________.

____

Participant

Exhibit 10.31

OGE ENERGY CORP.
FORM OF RESTRICTED STOCK AGREEMENT
UNDER 2003 STOCK INCENTIVE PLAN

OGE Energy Corp., (the "Company") hereby awards to _(name)_ (the "Participant") _(#)_ shares pursuant to the Stock Incentive Plan for OGE Energy Corp. (the "Plan"), the definitions and provisions of which are incorporated herein by reference.

The specific terms and conditions of the award are set forth hereinafter.

1. Number of Shares and Restriction Period. The shares awarded to Participant may not be sold, assigned, pledged, hypothecated or otherwise disposed of and shall be subject to a risk of forfeiture during the Restriction Period, beginning on the date of this Agreement and ending _____.

2. Additional Condition. In accordance with Section 7(a) of the Plan, the shares awarded hereby are subject to the additional condition that the number of shares to be received by the Participant upon the expiration of the Restriction Period is dependent upon the Company's Average Percentile Ranking for the Restriction Period (as hereinafter defined). In calculating the Company's Average Percentile Ranking for the Restriction Period, the following steps shall be taken: (i) first, the Company shall calculate, on a consolidated basis, its Return on Average Equity for each of the years ended December 31, ____, December 31, ____ and December 31, ____; and (ii) next, the Company shall calculate (to the nearest .01 of 1%) its percentile ranking for each such year by comparing the Company's return on average equity for each such year to the return on average equity for the companies listed as Annex A hereto (or their successors from a merger or other combination with another company on the list) as reported on Bloomberg for the same year (or, if such data is no longer reported on Bloomberg, from such other comparable source as selected by the Compensation Committee in its sole discretion). The Company's Average Percentile Ranking for the Restriction Period shall be the arithmetic average of the Company's percentile ranking (determined in accordance with clause (ii) above) for the year ended December 31, ____, for the year ended December 31, ____, and for the year ended December 31, ____.

The number of shares awarded hereby that the Participant shall be entitled to receive at the end of the Restriction Period shall be determined by the following schedule:

Company's Average Percentile Ranking for the Restriction Period	> ___th	____	___th	____	<___th
% of Awarded Shares to be Received by Participant	100%	75%	50%	25%	0

The number of shares awarded hereby that the Participant shall be entitled to receive for a percentile ranking between those shown above shall be determined through straight-line interpolation; provided, that, in all cases, the number of shares which a Participant is entitled to receive shall be a whole number (disregarding any fractions). Any shares awarded hereby that the Participant is not entitled to receive at the end of the Restriction Period pursuant to the foregoing schedule shall be deemed forfeited and the Company shall be authorized to cancel such shares at the end of the Restriction Period.

The provisions of this Section 2 shall not affect in any way any forfeiture under clause (c) of Section 7 of the Plan, any lapsing of the risk of forfeiture or Restriction Periods under clause (c) of Section 7 of the Plan, or any lapsing of Restriction Period(s) or other conditions under Section 7 of the Plan, or any acceleration of vesting under Section 9 of the Plan. Any such forfeiture, lapsing or acceleration shall occur to the same extent as if the provisions of this Section 2 did not exist.

3. Issuance of Certificate(s).

(a) Contemporaneously with the execution of this Agreement, the Company is issuing to the Participant a Certificate evidencing the number of shares subject to this award, and the Participant has executed a stock power in blank which, together with the Certificate, has been returned to the Company to be held in safekeeping pursuant to the Plan.

(b) As soon as practicable after the expiration or lapsing of the Restriction Period, the Company will issue to the Participant a Certificate (without legend), evidencing the number of shares that the Participant is entitled to receive under Section 2 above (less the number of shares, if any, withheld pursuant to Section 6(b) below) and with respect to which the restrictions on transfer and risk of forfeiture have lapsed.

4. Forfeiture. Except as otherwise explicitly provided in the Plan, in the event that Participant incurs a Termination of Employment due to death, disability, or retirement at or after age 62 or at or after obtaining 80 points of combined age and service under the OGE Energy Retirement Plan, then the Restriction Period shall lapse; provided, however, that if the Termination of Employment is due to retirement at or after age 62, or at or after obtaining 80 points, the applicable Performance Goals must be satisfied before the Restriction Period shall lapse. Upon occurrence of an event which pursuant to the Plan results in forfeiture of the shares then subject to a Restriction Period, the Company is authorized to cancel the Certificate evidencing such shares and return same to the Company.

5. Acceptance of Award. By execution of this Agreement, the Participant accepts the award, acknowledges receipt of a copy of the Plan (a copy of which is attached as Annex I), and represents that the Participant is familiar with the terms and provisions thereof and agrees to be bound thereby. Participant further agrees to accept as binding, conclusive and final all decisions or interpretations of the Compensation Committee with respect to any questions arising under the Plan, including any calculation of, or in connection with, the Company's Average Percentile Ranking for the Restriction Period.

6. Taxes and Other Matter.

(a) By execution of this Agreement, the Participant agrees to pay all withholding and other taxes payable with respect to the shares evidenced by this Agreement, at such times and in such manner as the Company may request and to comply with all Federal and State securities laws.

(b) Participant may elect, subject to approval of the Board of Directors or a committee composed of two or more non-employee directors within the meaning of Rule 16b-3(b)(3) of the Securities Exchange Act of 1934 or any successor provision thereto, to satisfy Participant's tax withholding requirements upon expiration or lapsing of the Restriction Period, in whole or in part, by having the Company withhold shares having a fair market value equal to all or a portion of the amount required to be withheld. The value of the shares to be withheld is to be based upon the same price of the shares that is utilized to determine the amount of withholding tax that the Participant owes. All elections under this Section 6(b) shall be (i) irrevocable, (ii) made in writing and signed by the Participant on the form attached hereto as Annex II and (iii) submitted to the Board of Directors prior to the November Board of Directors meeting that immediately precedes the date the Restriction Period expires or the shares otherwise become taxable.

7. Other Condition. The award of shares evidenced by this Agreement shall be subject to delivery to the Company of an executed copy of this Agreement, together with a stock power (in the form attached hereto), executed in blank by Participant.

Dated this _____ day of ______,___,

OGE ENERGY CORP.

BY: ______________________________

Chairman of the Board, President and
Chief Executive Officer

ACCEPTED AND AGREED TO this__________________________________ day of ______________________________

____

Participant

Exhibit 10.32

OGE ENERGY CORP.
FORM OF SPLIT DOLLAR AGREEMENT

EXHIBIT A
ENDORSEMENT

Appln. No. Contract No.,
or Policy No. Employee/Annuitant

1. The Owner of the policy will be OGE Energy Corporation Restoration and Retirement Income Benefits Rabbi Trust dated January 1, 1998. The Owner alone may exercise all policy rights, except that the Owner will not have the rights specified in 2. below.

Said Owner designates itself or its successors as direct beneficiary of the amount of the death proceeds, if any, in excess of the Employee's share of the proceeds, which share shall equal three times the Employee's annual base salary at the time of death.

The Insurer will have the right to rely on any statement signed by said Owner setting forth the amount referred to above, and any decisions made by the Insurer in reliance upon such statement will be conclusive and will fully protect the Insurer.

2. The Employee will have the rights to designate and change the beneficiaries of and assign the proceeds not payable in 1. above (This paragraph will not limit the rights of the Owner as specified in 1. above.)

Unless otherwise designated, the Employee designates his Estate as direct beneficiary of the proceeds specified in 2. above.

3. Termination of employment: In the event of termination of the Insured's employment, other than by death or retirement, said corporation will be the sole unrestricted Owner of the policy, and the Direct Beneficiary of the entire policy proceeds, and the beneficial and ownership rights vested in the Insured as stated in 2. above will terminate.

The Insurance Company will have the right to rely on any statement signed by said Owner as to termination of employment of the Insured. Any decisions made by the Insurance Company in reliance upon such statement will be conclusive and will fully protect the Insurance Company.

FOR HOME OFFICE USE

Form Recorded and Endorsement Waived — The Northwestern Mutual Life Insurance Company

Date ____________________________ By _______________________________________

Taxpayer No. : 73-1313523

Under penalties of perjury, the Owner, by signature of its duly authorized officer, below, hereby certifies (1) that the number shown on this form is its correct Employer Identification Number, and (2) that it is not subject to backup withholding because (a) it has not been notified by the IRS that it is subject to backup withholding as a result of failure to report all interest or dividends, or (b) if it ever was so notified, the IRS has notified it that it is no longer subject to backup withholding.

Date: ____

Owner

By ____

____

Witness

Officer Title

_________________________ ____

Witness

Employee

FOR HOME OFFICE USE

Form Recorded and Endorsement Waived

Date ____________________________

The Northwestern Mutual Life Insurance Company

By _______________________________________

Additional Provisions

A. This revokes all prior designations of beneficiaries of the death proceeds and elections of payment plans for them.

B. Solely for the purpose of this form, the person or entity named in 2. will be considered the "owner" of the policy rights specified in 2.

C. Any collateral assignment made by the Owner will be deducted only from the proceeds payable in 1.

D. Any assignment of the proceeds specified in 2. will be limited to the death proceeds only from the proceeds payable in 2.

E. Any indebtedness on the policy will first be deducted from the proceeds payable in 1.

F. The exercise by the Owner of the right to surrender the policy or to change the Insured will terminate the rights of the owner of the policy rights specified in 2.

G. The policy rights specified in 1. and 2. may be exercised by the respective owners named in 1. and 2. or their successors or transferees.

H. Each Owner of the proceeds specified in 1. and 2. will have the right to exercise the conversion privilege if applicable to such portion and will be the Owner of any new policy issued in lieu of such benefit.

I. In this form "Insured" means "Annuitant" when the form applies to an annuity contract.

J. If this form applies to more than one policy, it applies to the policies as a group and not to each policy individually.

K. All provisions of the policy to the contrary of this form are suspended.

L. The Company will be fully discharged on liability for any action taken by a Trustee in the exercise of any policy right and for all amounts paid to or at the direction of Trustee and will have no obligation as to the use of the amounts. In the dealings with the Trustee the Company will be fully protected against the claims of every other person. The Company will not be charged with notice of a change of trustee unless written evidence of the change is received at the Home Office.

FOR HOME OFFICE USE

Form Recorded and Endorsement Waived

Date ____________________________

The Northwestern Mutual Life Insurance Company

By _______________________________________

Exhibit 12.01

OGE Energy Corp.
S E C Method of Ratio of Earnings to Fixed Charges

	Year Ended Dec 31, 2000	Year Ended Dec 31, 2001	Year Ended Dec 31, 2002	Year Ended Dec 31, 2003	Year Ended Dec 31, 2004
Earnings:					
Pre-tax income from continuing operations	$ 205,901,058	$ 146,764,324	$ 125,499,559	$ 209,238,801	$ 233,226,761

Add Fixed Charges	139,931,555	132,199,580	115,552,863	102,194,363	101,267,858
Subtotal	345,832,613	278,963,904	241,052,422	311,433,164	334,494,619
Subtract:					
Allowance for funds used during construction	2,229,277	707,822	905,189	538,624	1,661,732
Minority interest - NOARK	1,243,067	953,181	134,579	(1,376,897)	(576,139)
Total Earnings	342,360,269	277,302,901	240,012,654	312,271,437	333,409,026
Fixed Charges:					
Long-term debt interest expense	118,720,004	115,481,869	103,492,446	92,489,615	88,092,896
Other interest expense	16,173,031	12,462,336	8,250,174	6,045,733	9,647,378
Calculated interest on leased property	5,038,520	4,255,375	3,810,243	3,659,015	3,527,584
Total Fixed Charges	$ 139,931,555	$ 132,199,580	$ 115,552,863	$ 102,194,363	$ 101,267,858
Ratio of Earnings to Fixed Charges	2.45	2.10	2.08	3.06	3.29

Exhibit 21.01

OGE Energy Corp.
Subsidiaries of the Registrant

Name of Subsidiary	Jurisdiction of Incorporation	Percentage of Ownership
Oklahoma Gas and Electric Company	Oklahoma	100.0
Enogex Inc.	Oklahoma	100.0
Enogex Products Corporation	Oklahoma	100.0
Enogex Gas Gathering, L.L.C	Oklahoma	100.0
OGE Energy Resources, Inc.	Oklahoma	100.0

The above listed subsidiaries have been consolidated in the Registrant’s financial statements.

Exhibit 23.01

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in the Registration Statement (Form S-8 No. 333-71327) pertaining to the stock incentive plan, the Registration Statement (Form S-8 No. 333-92423) pertaining to the deferred compensation plan, the Registration Statement (Form S-8 No. 333-104497) pertaining to the employees’ stock ownership and retirement savings plan, the Registration Statement (Form S-8 No. 333-115735) pertaining to the 2003 stock incentive plan, the Registration Statement (Form S-3 No. 333-118848) pertaining to debt securities, the Registration Statement (Form S-3 No. 333-104552) pertaining to debt securities, common stock and preferred share purchase rights and the Registration Statement (Form S-3 No. 333-104263) pertaining to the dividend reinvestment and stock purchase plan, of our reports dated February 23, 2005, with respect to the consolidated financial statements and schedule of OGE Energy Corp., OGE Energy Corp. management’s assessment of the effectiveness of internal control over financial reporting, and the effectiveness of internal control over financial reporting of OGE Energy Corp., included in this Annual Report (Form 10-K) for the year ended December 31, 2004.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 23, 2005

Exhibit 24.01

POWER OF ATTORNEY

WHEREAS, OGE ENERGY CORP., an Oklahoma corporation (herein referred to as the “Company”), is about to file with the Securities and Exchange Commission, under the provisions of the Securities Exchange Act of 1934, as amended, its annual report on Form 10-K for the year ended December 31, 2004; and

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

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

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

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

STATE OF OKLAHOMA)
) SS
COUNTY OF CANADIAN)

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

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

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

My Commission Expires:
May 3, 2007

Exhibit 31.01

CERTIFICATIONS

I, Steven E. Moore, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: February 25, 2005

/s/ Steven E. Moore

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

Exhibit 31.01

CERTIFICATIONS

I, James R. Hatfield, certify that:

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

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

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

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

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

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

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

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

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

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

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

Date: February 25, 2005

/s/ James R. Hatfield

James R. Hatfield
Senior Vice President and
Chief Financial Officer

Exhibit 32.01

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

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

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

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

February 25, 2005

/s/ Steven E. Moore

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

/s/ James R. Hatfield

James R. Hatfield
Senior Vice President and
Chief Financial Officer

Exhibit 99.01

OGE Energy Corp. 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 OGE Energy Corp. (the “Company”). Such statements are based on management’s beliefs as well as assumptions made by and information currently available to management. When used in the Company’s documents or oral presentations, the words “anticipate”, “estimate”, “expect”, “objective” and similar expressions are intended to identify forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause the Company’s actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following, by segment:

Consolidated (including Electric Utility and Natural Gas Pipeline Segments)

- 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 default;
- Economic conditions including availability of credit, actions of rating agencies and their impact on our ability to access the capital markets, inflation rates and monetary fluctuations;
- 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 the EPA, the ODEQ or other governing agencies 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 any of its subsidiaries 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 17 of Notes to Consolidated Financial Statements of the Company's Annual Report on Form 10-K for the year ended December 31, 2004, under the caption Commitments and Contingencies;

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

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

Electric Utility Segment

- 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;

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

Natural Gas Pipeline Segment

- Increased competition in the natural gas processing industry, including effects of decreasing margins as a result of competitive pressures and commodity exposure; and nature of competitors entering the industry;

- Cold weather extremes that may impact the ability of producing customers to maintain gas deliveries, or the quality of such deliveries, into the pipeline system;

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.