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

FORM 10-K

(Mark One)
[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2005

OR

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.Yes X No ___

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one): Large Accelerated Filer X Accelerated Filer ___ Non-Accelerated Filer ___

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

As of June 30, 2005, the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of shares of common stock held by non-affiliates was $2,605,521,218 based on the number of shares held by non-affiliates (90,031,832) and the reported closing market price of the common stock on the New York Stock Exchange on such date of $28.94.

As of January 31, 2006, 90,570,241 shares of common stock, par value $0.01 per share, were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The Proxy Statement for the Company's 2006 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, 2005

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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 related services for 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. For financial information regarding these segments, see Note 13 of Notes to Consolidated Financial Statements.

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, 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 15 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. Prior to October 31, 2005, Enogex owned, through a 75 percent interest in the NOARK Pipeline System Limited Partnership ("NOARK"), a controlling interest in and operated Ozark Gas Transmission, L.L.C. ("OGT"), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. On October 31, 2005, Enogex sold its interest in Enogex Arkansas Pipeline Corporation ("EAPC"), which held the NOARK interest. Also, during the third quarter of 2005, Enogex Compression Company, LLC ("Enogex Compression") sold it majority interest in Enerven Compression Services, LLC ("Enerven"), a joint venture focused on the rental of natural gas compression assets. The EAPC and Enerven businesses have been reported as discontinued operations in the Company's Consolidated Financial Statements and are discussed further in Note 4 of Notes to Consolidated Financial Statements.

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

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. As explained below, 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 weather-normalized basis, an annual total return in the top third of its peer group, dividend growth and maintenance of strong credit ratings.

OG&E has been focused on its Customer Savings and Reliability Plan, which provides for increased investment at the utility to improve reliability and meet load growth, replace infrastructure equipment and deploy newer technology that improves operational and environmental performance. As part of this plan, OG&E purchased a 77 percent interest in the 520 megawatt ("MW") natural gas-fired combined cycle NRG McClain Station (the "McClain Plant") in July 2004. Capacity payment savings from reduced cogeneration payments and fuel savings from the McClain Plant will be utilized to help mitigate the price increases associated with these investments. In 2005 OG&E filed a rate case to recover, among other things, its investment in, and the operating expenses of, the McClain Plant. An order was issued by the OCC on December 12, 2005 providing for a rate increase of approximately $42.3 million and OG&E implemented the new electric rates in

January 2006. For additional information regarding the McClain Plant acquisition, the new electric rates and related regulatory matters, see Note 15 of Notes to Consolidated Financial Statements.

Enogex 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 and Rocky Mountain markets. Also, in 2005, Enogex's marketing business implemented a refocused strategy that seeks to minimize the amount of capital employed and to complement better the natural gas pipeline business. Enogex's improved financial performance and increased flexibility from the reduction of its long-term debt has enabled Enogex to begin to contribute to funding the Company's dividend. As discussed above, during 2005, Enogex sold its interests in EAPC and Enerven and will continue to review its asset portfolio and seek to divest underperforming or non-strategic assets.

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, 2005, OG&E and Enogex represented approximately 66 percent and 32 percent, respectively, of the Company's consolidated assets. The remaining two 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 2005, five other communities and four rural electric cooperatives in Oklahoma and western Arkansas purchased electricity from OG&E for resale. The service area, with an estimated population of 2.0 million, covers approximately 30,000 square miles in Oklahoma and western Arkansas, including Oklahoma City, the largest city in Oklahoma, and Fort Smith, Arkansas, the second largest city in that state. Of the 269 communities that OG&E serves, 243 are located in Oklahoma and 26 in Arkansas. OG&E derived approximately 88 percent of its total electric operating revenues for the year ended December 31, 2005 from sales in Oklahoma and the remainder from sales in Arkansas.

OG&E's system control area peak demand as reported by the system dispatcher during 2005 was approximately 6,145 MW's on July 22, 2005. OG&E's load responsibility peak demand was approximately 5,766 MW's on July 22, 2005, resulting in a capacity margin of approximately 15.8 percent. As reflected in the table below and in the operating statistics on page 3, there were approximately 26.1 million megawatt-hour ("MWH") sales in 2005 as compared to approximately 24.8 million in 2004 and 25.1 million in 2003. MWH sales to OG&E's customers ("system sales") increased approximately 5.3 percent in 2005 primarily due to warmer weather during 2005. Sales to other utilities and power marketers ("off-system sales") remained flat in 2005. Variances in off-system sales are due in large part to the changing supply and demand needs on 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:

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

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

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

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 15 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)*	**2005**	2004	2003
ELECTRIC ENERGY *(Millions of MWH)*			
Generation (exclusive of station use)	**24.8**	22.6	22.5
Purchased	**3.3**	4.2	4.5
Total generated and purchased	**28.1**	26.8	27.0

Company use, free service and losses	**(2.0)**	(2.0)	(1.9)
Electric energy sold	**26.1**	24.8	25.1
ELECTRIC ENERGY SOLD *(Millions of MWH)*			
Residential	**8.5**	7.9	8.2
Commercial	**6.0**	5.7	5.8
Industrial	**7.2**	7.0	6.8
Public authorities	**2.8**	2.7	2.7
Sales for resale	**1.5**	1.4	1.5
System sales	**26.0**	24.7	25.0
Off-system sales	**0.1**	0.1	0.1
Total sales	**26.1**	24.8	25.1
ELECTRIC OPERATING REVENUES *(In millions)*			
Residential	$ **663.6**	$ 611.4	$ 601.4
Commercial	**418.9**	389.9	372.5
Industrial	**355.6**	326.7	293.4
Public authorities	**173.1**	158.5	146.1
Sales for resale	**67.7**	57.0	57.7
Provision for refund on gas transportation and storage case	**(2.0)**	(6.9)	- --
System sales revenues	**1,676.9**	1,536.6	1,471.1
Off-system sales revenues	**4.9**	0.8	4.1
Other	**38.9**	40.7	41.9
Total Electric Operating Revenues	$ **1,720.7**	$ 1,578.1	$ 1,517.1
ACTUAL NUMBER OF ELECTRIC CUSTOMERS *(At end of period)*			
Residential	**639,733**	630,736	622,527
Commercial	**81,728**	80,786	80,265
Industrial	**9,472**	9,420	8,970
Public authorities	**14,515**	14,022	13,658
Sales for resale	**45**	44	50
Total	**745,493**	735,008	725,470
AVERAGE RESIDENTIAL CUSTOMER SALES			
Average annual revenue	$ **1,043.60**	$ 975.08	$ 970.04
Average annual use (kilowatt-hour ("KWH"))	**13,445**	12,630	13,202
Average price per KWH (cents)	$ **7.76**	$ 7.72	$ 7.35

Regulation and Rates

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

Regulatory Matters

Gas Transportation and Storage Agreement

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

On July 14, 2005, the OCC issued an order in this case approving a $41.9 million annual recovery. The OCC order disallowed the recovery by OG&E of the amount that Enogex charges OG&E for the cost of fuel used, or otherwise unaccounted for, in providing natural gas transportation and storage service to OG&E. Over the last three years, this amount has ranged from $1.2 million to $3.7 million annually. This amount was approximately $1.2 million in 2005 and is projected to be approximately $0.5 million in 2006. The OCC's order required OG&E to refund to its Oklahoma customers the difference between the amounts collected from such customers in the past based on an annual rate of $46.8 million for gas transportation and storage services and the $41.9 million annual rate authorized by the OCC's order. Based on the order, OG&E's refund obligation was approximately $8.8 million. OG&E began refunding this obligation in September 2005 through its automatic fuel adjustment clause. The balance of the refund obligation was approximately $6.0 million at December 31, 2005. For further information, see Note 15 of Notes to Consolidated Financial Statements.

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

OG&E Oklahoma Rate Case Filing

On May 20, 2005, OG&E filed with the OCC an application for an annual rate increase of approximately $89.1 million to recover, among other things, its investment in, and the operating expenses of, the McClain Plant. As a result of the McClain Plant acquisition completed on July 9, 2004, and consistent with the Settlement Agreement with the OCC, OG&E had the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the acquisition and operation of

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the McClain Plant, consisting of the non-fuel operation and maintenance expenses, depreciation, cost of debt associated with the investment and ad valorem taxes. OG&E's rate case application included an estimate of $25.9 million related to the McClain Plant regulatory asset. At December 31, 2005, the actual incurred expenses included in the McClain Plant regulatory asset were approximately $24.9 million. Such costs will be recovered over a four-year time period as authorized in the OCC rate order beginning in January 2006. The OCC also authorized approximately $15.5 million of the $24.9 million regulatory asset to be included in OG&E's rate base for purposes of earning a return. The application also included, among other things, implementation of enhanced reliability programs in OG&E's system, increased fuel oil inventory, the establishment of a separate recovery mechanism for major storm expense, the establishment of new rate classes for public schools and related facilities, the establishment of a military base rider, the establishment of a new low income assistance tariff and the proposal to make the guaranteed flat bill pilot tariff permanent for residential and small business customers.

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

Southwest Power Pool

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

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

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.

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, 2005 and 2004, OG&E had regulatory assets of approximately $189.2 million and $137.3 million, respectively, and regulatory liabilities of approximately $118.1 million and $122.2 million, respectively.

As discussed in Note 15 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. 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. 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 15 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, OG&E's 2005 rate case order, security enhancements, national energy legislation and state legislative initiatives.

Rate Activities and Proposals

Since 2002, OG&E has had several different customer programs and rate options. The Guaranteed Flat Bill ("GFB") option for residential and small general service accounts allows qualifying customers the opportunity to purchase their electricity needs at a set price for an entire year. Budget-minded customers that desire a fixed monthly bill may benefit from the GFB option. The GFB option received OCC approval for permanent rate status in OG&E's recently concluded rate case. A second tariff rate option provides 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 rate offering available to commercial and industrial customers is levelized demand billing. This program is beneficial for medium to large size customers with seasonally consistent demand levels who wish to reduce the variability of their monthly electric bills. Another program being offered to OG&E's commercial and industrial customers is a voluntary load curtailment program. This program provides customers with the opportunity to curtail on a voluntary basis when 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 rate options coupled with OG&E's other 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. The revenue impacts associated with these options are indeterminate in future years since customers may choose to remain on existing rate options instead of volunteering for the new rate option choices. There was no overall material impact in 2004 or 2005 associated with these rate options, but minimal revenue variations may occur in the future based upon changes in customers' usage characteristics if they choose these programs. In 2005, the GFB pilot customers continued to renew at the 2004 renewal rate of over 90 percent.

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

Fuel Supply

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

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

The increase in the weighted average cost of fuel in 2005 and in 2004 was primarily due to increased natural gas prices and increased amounts of natural gas being burned. The increase in the weighted average cost of fuel in 2003 as compared to 2002 was primarily due to increased natural gas prices in 2003 partially offset by a lower amount of natural gas burned in 2003. The decrease in the weighted average cost of fuel in 2002 as compared to 2001 was primarily due to lower natural gas prices in 2002 partially offset by a higher amount of natural gas burned in 2002. A portion of these fuel costs is included in the base rates to customers and differs for each jurisdiction. The portion of these fuel costs that is not included in the base rates is recoverable through OG&E's regulatorily approved automatic fuel adjustment clauses. See Note 1 of Notes to Consolidated Financial Statements.

Coal

All of OG&E's coal-fired units, with an aggregate capability of approximately 2,569 MW's, are designed to burn low sulfur western coal. OG&E purchases coal primarily under long-term contracts expiring in years 2010 and 2011. During 2005, OG&E purchased approximately 9.2 million tons of coal from the following Wyoming suppliers: Kennecott Energy Company, Arch Coal Inc./Triton Coal Company, Peabody Coal Sales Company and Foundation Coal West, Inc. The combination of all coal has a weighted average sulfur content of less than 0.23 percent and can be burned in these units under existing federal, state and local environmental standards (maximum of 1.2 lbs. of sulfur dioxide per MMBtu) without the addition of sulfur dioxide removal systems. Based upon the average sulfur content, OG&E's coal units have an approximate emission rate of 0.49 lbs. of sulfur dioxide per MMBtu, well within the limitations of the provisions of the Federal Clean Air Act discussed in Note 15 of Notes to Consolidated Financial Statements.

OG&E has continued its efforts to maximize the utilization of its coal-fired units at its Sooner and Muskogee generating plants. See "Environmental Laws and Regulations" in Note 14 of Notes to Consolidated Financial Statements for a discussion of environmental matters affecting OG&E.

Coal Shipment Disruption

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

Natural Gas

OG&E utilized a request for bid ("RFB") to acquire approximately 30 percent of its projected annual natural gas requirements for 2006. All of these contracts are tied to various gas price market indices and most will expire in December

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2006. Additional natural gas supply for the summer of 2006 will be secured through a new RFB issued in the first quarter of 2006. 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. At December 31, 2005, OG&E had approximately 2.7 million MMBtu's in natural gas storage that it acquired for approximately $10.5 million.

Wind

During 2003, OG&E contracted with FPL Energy for 50 MW's of electricity generated at a wind farm near Woodward, Oklahoma. After more than one year of marketing wind power to OG&E's residential and business customers, almost 9,000 subscribed for all or part of their electricity usage. As of January 31, 2006, OG&E's current wind program is fully subscribed. 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.

On December 22, 2005, the Company issued a press release announcing that OG&E had entered into a non-binding letter of intent to purchase a 120 MW wind farm planned for construction in northwestern Oklahoma. Invenergy Wind Development Oklahoma LLC ("Invenergy LLC") would develop the new wind power-generation facility to be owned and operated by OG&E. The wind farm, north of Woodward in Harper County, is expected to cost approximately $195 million, including the cost of transmission interconnection facilities. A definitive Agreement To Engineer, Procure and Construct Wind Generation Energy System ("EPC Contract") was reached on February 20, 2006, subject to various conditions. Those conditions include agreement by the parties as to certain exhibits to the EPC Contract, approval of the EPC Contract by the OG&E Board of Directors and approval of the EPC Contract by the Manager of Invenergy LLC, all of which have to be completed on or before March 13, 2006. In addition, 90 days subsequent to the occurrence of these events, OG&E or Invenergy LLC have the unilateral right to terminate the EPC Contract if certain additional events have not occurred, including the following: (i) OCC approval of the terms of the EPC Contract and of a recovery rider providing OG&E the opportunity to recover all costs associated with the wind facility, including transmission interconnection and transmission upgrade costs; (ii) completion by the SPP of all necessary transmission studies; (iii) Invenergy LLC's acquisition of certain land agreements; (iv) Invenergy LLC's execution of a contract acceptable to OG&E with a balance of work contractor; and (v) Invenergy LLC's acquisition of certain permits. If all of these conditions are met, the new wind farm is expected to be constructed and producing power on or before December 31, 2006. OCC hearings are expected to occur in April 2006. See Note 15 of Notes to Consolidated Financial Statements for a further discussion.

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 8,300 miles of intrastate gas gathering and transportation pipelines. Prior to October 31, 2005, Enogex owned, through a 75 percent interest in NOARK, a controlling interest in and operated OGT, a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. On October 31, 2005, Enogex sold its interest in EAPC, which held the NOARK interest. Also, during the third quarter of 2005, Enogex Compression sold it majority interest in Enerven, a joint venture focused on the rental of natural gas compression assets. The EAPC and Enerven businesses have been reported as discontinued operations in the Company's Consolidated Financial Statements and are discussed further in Note 4 of Notes to Consolidated Financial Statements.

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 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 the 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. 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.

Besides the core activities described above, the transportation capabilities and markets of Enogex’s pipeline assets provide other business opportunities. These include the ability of Enogex to use its pipeline system and storage assets as a “market hub”. At December 31, 2005, Enogex was connected to 14 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. As a result, Enogex’s assets sit in a key geographic region of the United States, with sufficient capacity to provide crosshaul transportation and storage services to a variety of utility and industrial customers that need to access mid-continent natural gas 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 provides products and services that support the market hub concept and are an important element in the Company realizing the full value of its transportation and storage assets. 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 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.

On November 4, 2005, Enogex announced that it had entered into a letter of intent with El Paso Corporation (“El Paso”) that is designed to accelerate El Paso’s Continental Connector Project. The letter of intent contemplates arrangements by which El Paso or an affiliate would execute an initial lease of up to 750,000 decatherms per day (“Dth/day”) of capacity on the Enogex pipeline system, with an option to expand up to 1.5 million Dth/day, so that the leased Enogex pipeline capacity would become an integral part of the Continental Connector Project. The letter of intent also contemplates a commitment by Enogex to secure up to 500,000 Dth/day of capacity subscriptions for the project. These arrangements would significantly reduce the amount of new mainline construction required for the project, resulting in less environmental disturbance and an earlier in-service target date of winter 2007-2008.

Under the letter of intent, the Continental Connector Project will use existing or expanded El Paso pipeline systems to transport capacity-constrained natural gas from Rocky Mountain and mid-continent supply regions to Custer, Oklahoma.

At Custer, this gas and local mid-continent production will be transported on existing and expanded Enogex systems for Continental Connector under a long-term lease arrangement for re-delivery in the vicinity of Bennington, Oklahoma. From there, gas will be transported on new El Paso pipeline facilities through the Perryville, Louisiana, Hub to a termination with Tennessee and Southern Natural Pipelines at Pugh, Mississippi.

Enogex intends to work with El Paso to determine whether to advance this project. However, the commitments and obligations under the letter of intent are subject to various conditions, including definitive documentation and boards of directors' and regulatory approvals and there can be no assurance that the conditions will be satisfied. Pending satisfaction of these conditions, Enogex does not expect to incur material expenditures.

Dispositions

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.

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.

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 either contributed the assets to the joint venture described below 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 was 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 held a majority ownership in the joint venture, although the actual ownership percentages fluctuated based on the relative capital contributions of Enogex Compression and the third party member. The third party acted as the manager and conducted the daily operations of the joint venture. In April 2005, Enogex Compression received an unsolicited offer to buy its interest in Enerven. After evaluating this offer, Enogex Compression sold its interest in Enerven for approximately $7.3 million in August 2005. Enogex Compression recognized an after tax gain of approximately $1.8 million related to the sale of this business.

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.

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 were shut down and service was 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.

In January 2003, OGT 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.

Enogex regularly evaluates the long term stability, profitability and core competency of each of its businesses within the regulatory and market framework in which each business operates. Based on these evaluations, in September 2005, Enogex announced that it had entered into an agreement to sell its interest in EAPC, which held the NOARK interest. This sale was completed on October 31, 2005. The Company received approximately $177.4 million cash proceeds and recognized an after tax gain of approximately $36.7 million from the sale of this business in the fourth quarter. Enogex used approximately $31.9 million of the proceeds to repay principal and accrued interest on long-term debt and approximately $46.7 million to pay taxes associated with EAPC. The balance of the proceeds of approximately $98.8 million will be used to invest, over time, in strategic assets to diversify its asset base.

Capital Expenditures; Improvement Projects.

In 2005, Enogex completed a major upgrade of its information systems that began in 2003. 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. One information system implemented provided a single system for pipeline equipment control, data collection, management and measurement of gas volumes and pressures, which has improved Enogex's access to critical data for daily system management decisions. Another information system implemented, together with the Company's primary enterprise-wide general ledger software, has been used to accumulate and analyze financial data used in financial reporting. This change in information systems was made to eliminate previous stand alone systems and integrate them into one system.

On a company-wide basis, the Company is the process of implementing an enhanced digital asset mapping technology for both OG&E and Enogex and expects to complete the implementation of this new technology by May 2006. The new system is expected to support a significant increase in the number of members who use this technology in their jobs, expanding the productive use of geographic asset information in a variety of ways, including daily operations, maintenance, budgeting, planning, purchasing and accounting. Also, Enogex began work on a flow data access project called ProductionWatch at the end of the second quarter of 2005. Initial phases of implementation are expected to be completed by mid-year 2006 with the final phases of implementation of this project being completed by the end of 2007. ProductionWatch is a service that provides data (volume, pressure, temperature, etc.) from the Enogex meter to Enogex's customers for a fee. ProductionWatch data will be available to customers via the internet and it may also be downloaded by customers from Enogex network servers. Such data is attractive because it enables Enogex customers to increase gas production and reduce operating costs. From Enogex's perspective, ProductionWatch provides Enogex with an additional revenue stream while helping Enogex operate more efficiently.

During 2004, Enogex made improvements to the Stuart Storage Facility which reduced water encroachment in the field. During 2004, approximately $1.9 million of capital investment was made on this project. There were no capital expenditures on this project in 2005. Enogex does not expect any material future expenditures on this water encroachment project.

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, the Anadarko basin of western Oklahoma and the Panhandle of West Texas. At December 31, 2005, Enogex was connected to 14 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., El Paso Natural Gas Pipeline, Enbridge Pipelines, Oneok WesTex Transmission L.P. and Ozark Gas Transmission, L.L.C. Further, Enogex is connected to various end-users including numerous electric generation facilities in Oklahoma that are fueled by natural gas. At December 31, 2005, the net property, plant and equipment balance for Enogex's transportation and storage business was approximately $522.4 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 negotiated with each customer. Both facilities are used to support Enogex's intrastate transportation and storage services for OG&E.

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 intrastate contracts. Enogex offers interruptible service to customers when capacity is available.

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, 2007, 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 2005, 2004 and 2003, Enogex’s revenues from its firm intrastate transportation and storage contracts were approximately $95.0 million, $95.6 million and $92.2 million, respectively.

As previously discussed, in October 2005, Enogex sold its interest in EAPC, which held the NOARK interest.

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 $34.9 million, $34.3 million and $33.5 million, respectively, during 2005, 2004 and 2003. The amount collected from OG&E by Enogex under the current contract for storage services was approximately $12.7 million, $15.3 million and $11.2 million, respectively, during 2005, 2004 and 2003. In July 2005, OG&E received an OCC order related to its application to recover the costs of gas transportation and storage services provided to OG&E by Enogex pursuant to the contract between OG&E and Enogex. See Note 15 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. Enogex’s approved Section 311 rate structure includes a provision for Enogex to charge a fixed fuel percentage for the fuel usage for natural gas shipped on its system. The fixed fuel percentage is adjusted annually and is in effect for a calendar fuel year (unless Enogex files with the FERC to adjust it more frequently). The mechanism used to recover such fuel is a fuel tracker that establishes a fixed fuel factor (expressed as a percentage of natural gas shipped) that is trued-up over a two year period and based on the value of the gas at the time of usage.

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. As a result, effective October 1, 2004, the FERC regulates Enogex’s Section 311 transportation and any regulation of gathering is pursuant to Oklahoma statute.

On September 30, 2004, Enogex made its required triennial filing at the FERC to update its Section 311 maximum interruptible transportation rate. On September 29, 2004, Enogex filed an updated fuel factor with the FERC for the last quarter of 2004. Finally, on November 15, 2004, Enogex filed its annual updated fuel factor for fuel year 2005 (calendar year 2005).

Various parties intervened and protested the four filings but, after three technical conferences and various settlement discussions, reached a unanimous settlement that the FERC approved without modification or condition, by order of September 19, 2005. The Settlement established new maximum interruptible Section 311 zonal rates for an East Zone and a West Zone on the Enogex system, confirmed that Enogex could unbundle its gathering and transportation services and permitted the fuel factor percentages for the last quarter of 2004 and for fuel year 2005 to become effective, as filed. The FERC order concluded all four proceedings which resulted in no refunds being due. Because the FERC requires all intrastate pipeline offering 311 service to file a rate case every three years, Enogex must file its next rate case no later than October 1, 2007.

As required by the fuel tracker provisions of the SOC, Enogex made its annual fuel filing for the 2006 fuel year on November 15, 2005. As agreed in the Settlement, the fuel filing for the first time proposed an East Zone fuel percentage and a West Zone fuel percentage to be recalculated annually to replace the system-wide fuel percentage previously calculated annually for the whole Enogex system. Four parties moved to intervene. One party posed questions about the filing that Enogex answered on January 19, 2006. The FERC Staff later served data requests that Enogex answered on February 17, 2006. The FERC has not yet acted on the filing.

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. 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 15 of Notes to Consolidated Financial Statements for a discussion of the OCC order OG&E received in July 2005 related to the amounts charged 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 2005, Gathering connected 272 new producing wells, located in the Anadarko and Arkoma basins of Oklahoma, 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 738 MMcfd. During 2002, Products had ownership interests in two other gas processing plants related to the NuStar Joint Venture, 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 2005, approximately 311 million gallons of natural gas liquids were sold. Enogex also had a lease for a small segment of gathering pipeline off of the Palo Duro pipeline system, referred to as the Northeast Lateral. This lease expired February 28, 2005. At December 31, 2005, the net property, plant and equipment balance for Enogex's gathering and processing business was approximately $352.9 million.

Approximately 20 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 a third party 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 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, but not eliminated, through contract renegotiations and changes in the SOC that provides for a default processing fee in the event the natural gas liquids revenue less the associated fuel and shrinkage costs is negative. 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 instruments to capture these spreads.

Enogex is also in the construction phase of a project to expand its gathering pipeline capacity on the west side of its system. This project is expected to be in service before September 2006. This expansion initiative should enable Enogex to benefit from economic growth opportunities in that marketplace.

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, OGE Energy Resources, Inc. ("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, 2005, the net property, plant and equipment balance for Enogex's marketing business was approximately $0.6 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. In 2005, OERI implemented a refocused strategy that seeks to minimize the amount of capital employed and to complement better the natural gas pipeline business. OERI has expanded into the Gulf Coast and Rocky Mountain markets to diversify its business and to facilitate Enogex's business development efforts.

OERI primarily 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. OERI's average daily sales volumes dropped from

approximately 1.8 Bcf in 2004 to 1.4 Bcf in 2005. This reflects selective deal execution to assure adequate margin in light of credit and other risks in the current high commodity price environment. 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 OERI 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 and daily value-at-risk limits of $1.5 million in accordance with corporate policies.

OERI and Cheyenne Plains Gas Pipeline Company, L.L.C. are parties to a firm transportation services agreement dated April 14, 2004. The Cheyenne Plains Pipeline provides interstate gas transportation services in Wyoming, Colorado and Kansas with a capacity of 560,000 Dth/day. Effective January 1, 2006, the capacity on the Cheyenne Plains Pipeline increased to 730,000 Dth/day. OERI reserved 60,000 Dth/day of firm capacity on the Cheyenne Plains Pipeline for 10 years. Such reservation provides OERI access to significant additional natural gas supplies in the Rocky Mountain production basins. OERI pays a demand fee of approximately $7.5 million annually for this capacity. OERI incurred a loss of approximately $3.6 million during 2005 related to its Cheyenne Plains' position as a result of unfavorable market conditions for the capacity primarily due to the 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. If the market conditions reflected in the current forward market price quotes continue for 2006, OERI expects to record a loss of approximately $1.4 million in 2006.

Competition. OERI competes in marketing natural gas with major integrated oil companies, marketing affiliates of major interstate and intrastate pipelines and commercial banks, national and local natural gas brokers, 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, 2005, approximately 59 percent of OERI's service volumes were with electric utilities, local gas distribution companies, pipelines and producers. The remaining 41 percent of service volumes were to marketers, municipals, cooperatives and industrials. At December 31, 2005, approximately 75.9 percent of the payment exposure was to companies having investment grade ratings with Standard & Poor's Ratings Services ("Standard & Poor's") and approximately 0.6 percent having less than investment grade ratings. The remaining 23.5 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.

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 2006 to 2008 construction program includes continued investment in OG&E’s and Enogex’s assets. OG&E plans to continue to invest in its electric system at a level consistent with 2005. These capital expenditures do not include any capital requirements associated with OG&E’s proposed wind power project pending approval from the OCC. OG&E has approximately 430 MW’s of contracts with qualified cogeneration facilities (“QF”) and small power production producers’ (“QF contracts”) that will expire at the end of 2007, unless extended by OG&E. For one of these QF contracts, OG&E purchases 100 percent of electricity generated by the QF. For the other QF contract, OG&E can purchase up to 17 percent of electricity generated by the QF. In addition, effective September 1, 2004, OG&E entered into a new 15-year power purchase agreement for 120 MW’s with PowerSmith Cogeneration Project, L.P. (“PowerSmith”), in which OG&E purchases 100 percent of electricity generated by PowerSmith. OG&E will continue reviewing all of the

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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 as well as wind generation facilities. See “Item 7. Management’s Discussion and Analysis of Financial Conditions and Results of Operations – Liquidity and Capital Requirements” for a discussion of the Company’s capital expenditures.

Pension and Postretirement Benefit Plans

During 2005 and 2004, the Company made contributions to its pension plan of approximately $32.0 million and $69.0 million, respectively, to ensure that the pension plan maintains an adequate funded status. During 2006, the Company may contribute up to $90 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, long and short-term debt and proceeds from the sales of common stock pursuant to the Company’s Automatic Dividend Reinvestment and Stock Purchase Plan will be adequate over the next three years to meet anticipated cash needs. 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 Note 11 of Notes to Consolidated Financial Statements for a table showing the Company’s lines of credit in place, commercial paper and available cash at December 31, 2005. At December 31, 2005, the Company’s short-term borrowings consisted of commercial paper.

ENVIRONMENTAL MATTERS

Approximately $5.0 million of the Company’s capital expenditures budgeted for 2006 are to comply with environmental laws and regulations. The Company’s management believes that all of its operations are in substantial compliance with present federal, state and local environmental standards. It is estimated that the Company’s total expenditures for capital, operating, maintenance and other costs to preserve and enhance environmental quality will be approximately $59.7 million during 2006 as compared to approximately $67.0 million in 2005. The Company continues to evaluate its environmental management systems to ensure compliance with existing and proposed environmental legislation and regulations and to better position itself in a competitive market. See Note 14 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 3,044 employees at December 31, 2005.

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 ("SEC").

Item 1A. Risk Factors.

In the discussion of risk factors set forth below, unless the context otherwise requires, the terms "OGE Energy", "we", "our" and "us" refer to OGE Energy Corp., "OG&E" refers to our subsidiary Oklahoma Gas and

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

REGULATORY RISKS

Our profitability depends to a large extent on the ability of OG&E to fully recover its costs from its customers and there may be changes in the regulatory environment that impair its ability to recover costs from its customers.

We are subject to comprehensive regulation by several federal and state utility regulatory agencies, which significantly influences our operating environment and OG&E's ability to fully recover its costs from utility customers. With rising fuel costs, recoverability of under recovered amounts from our customers is a significant risk. The utility commissions in the states where OG&E operates regulate many aspects of our utility operations including siting and construction of facilities, customer service and the rates that we can charge customers. The profitability of our utility operations is dependent on our ability to fully recover costs related to providing energy and utility services to our customers. On May 20, 2005, OG&E filed for an $89 million annual rate increase to recover investments in our electric system, including those related to our McClain Plant. Several parties made filings recommending a significantly lower increase and, in certain cases, rate decreases. On December 12, 2005, the OCC issued an order providing for a $42.3 million rate increase in OG&E's electric rates which became effective in January 2006. This rate order will require us to reduce planned electric system upgrades and expansion projects, and we are considering when to return to the OCC to seek further rate relief. We cannot assure you that the OCC will grant us rate increases in the future or in the amounts we request, and it could instead lower our rates.

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

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

OG&E's rates are subject to regulation by the states of Oklahoma and Arkansas, as well as by a federal agency, whose regulatory paradigms and goals may not be consistent.

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

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

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

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

OG&E's results of operations could be affected by OG&E's ability to renegotiate franchise agreements with municipalities and counties in Oklahoma.

OG&E has several franchise agreements with municipalities and counties in Oklahoma and OG&E's ability to renegotiate these agreements may affect our results of operations and financial position.

The regional power market in which OG&E operates has changing transmission regulatory structures, which may affect the transmission assets and related revenues and expenses.

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

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

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

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

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

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

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

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

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

We are subject to substantial regulation from federal, state and local regulatory agencies. We are required to comply with numerous laws and regulations and to obtain numerous permits, approvals and certificates from the governmental agencies that regulate various aspects of our businesses, including customer rates, service regulations, retail service territories, sales of securities, asset acquisitions and sales, accounting policies and practices and the operation of generating facilities. We believe the necessary permits, approvals and certificates have been obtained for our existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from future regulatory activities of these agencies.

OPERATIONS RISKS

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

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

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

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

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

FINANCIAL AND MARKET RISKS

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

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

In addition to the costs of our retirement plans, the costs of providing health care benefits to our employees and retirees have increased substantially in recent years. We believe that our employee benefit costs, including costs related to health care plans for our employees and former employees, will continue to rise. The increasing costs and funding requirements with our defined benefit retirement plan, health care plans and other employee benefits may adversely affect our results of operations, financial position, or liquidity.

We are a holding company with our primary assets being investments in our subsidiaries.

We are a holding company and thus our investments in our subsidiaries are our primary assets. Substantially all of our operations are conducted by our subsidiaries. Consequently, our operating cash flow and our ability to pay our dividends and service our indebtedness depends upon the operating cash flow of our subsidiaries and the payment of funds by them to us in the form of dividends. At December 31, 2005, we had outstanding indebtedness and other liabilities of approximately $3.5 billion. Our subsidiaries are separate legal entities that have no obligation to pay any amounts due on our indebtedness or to make any funds available for that purpose, whether by dividends or otherwise. In addition, each subsidiary's ability to pay dividends to us depends on any statutory and contractual restrictions that may be applicable to such subsidiary, which may include requirements to maintain minimum levels of working capital and other assets. Claims of creditors, including general creditors, of our subsidiaries on the assets of these subsidiaries will have priority over our claims generally (except to the extent that we may be a creditor of the subsidiaries and our claims are recognized) and claims by our shareowners.

In addition, as discussed above, OG&E is regulated by state utility commissions in Oklahoma and Arkansas which generally possess broad powers to ensure that the needs of the utility customers are being met. To the extent that the state commissions attempt to impose restrictions on the ability of OG&E to pay dividends to us, it could adversely affect our ability to continue to pay dividends.

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

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

Certain provisions in our charter documents and rights plan have anti-takeover effects.

Certain provisions of our certificate of incorporation and bylaws, as well as the Oklahoma corporations statute, may have the effect of delaying, deferring or preventing a change in control of OGE Energy. Such provisions, including those regulating the nomination of directors, limiting who may call special stockholders' meetings and eliminating stockholder action by written consent, together with the possible issuance of preferred stock of OGE Energy without stockholder approval, may make it more difficult for other persons, without the approval of our board of directors, to make a tender offer or otherwise acquire substantial amounts of our common stock or to launch other takeover attempts that a stockholder might consider to be in such stockholder's best interest. Additionally, our rights plan may also delay, defer or prevent a change of control of OGE Energy. Under the rights plan, each outstanding share of common stock has one half of a right attached that trades with the common stock. Absent prior action by our board of directors to redeem the rights or amend the rights plan, upon the consummation of certain acquisition transactions, the rights would entitle the holder thereof (other than the acquiror) to purchase shares of common stock at a discounted price in a manner designed to result in substantial dilution to the acquiror. These provisions could limit the price that investors might be willing to pay in the future for shares of our common stock, discourage third party bidders from bidding for us and could significantly impede the ability of the holders of our common stock to change our management.

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

We cannot assure you that any of our current ratings or our subsidiaries' will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances in the future so warrant. Any future downgrade could increase the cost of short-term borrowings but would not result in any defaults or accelerations as a result of the rating changes. Any downgrade could lead to higher borrowing costs and, if below investment grade, could require us to issue guarantees on behalf of Enogex to support some of OERI's marketing operations.

We are subject to commodity price risk.

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

We are also exposed to volatility from our 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 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, but not eliminated, through contract renegotiations and changes in the SOC that provides for a default processing fee in the event the natural gas liquids revenue less the associated fuel and shrinkage costs is negative. 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 instruments to capture these spreads. Despite these activities, we cannot assure that our exposure to keep-whole processing arrangements has been eliminated.

We mark our energy trading portfolio to estimated fair market value on a daily basis (mark-to-market accounting), which causes earnings variability. Market prices are utilized in determining the value of electric energy, natural gas and related derivative commodity instruments. For longer-term positions, which are limited to a maximum of 18 months, and certain short-term positions for which market prices are not available, models based on forward price curves are utilized. These models incorporate estimates and assumptions as to a variety of factors such as pricing relationships between various energy commodities and geographic locations. Actual experience can vary significantly from these estimates and assumptions.

We are subject to credit risk.

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

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

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

	2	1991	Combustion-Turbine	Gas	Base Load	40.4%	28.3	59.8
Enid	1	1965	Combustion-Turbine	Gas	Peaking	---(C)	---	
	2	1965	Combustion-Turbine	Gas	Peaking	---(C)	---	
	3	1965	Combustion-Turbine	Gas	Peaking	---(C)	---	
	4	1965	Combustion-Turbine	Gas	Peaking	---(C)	---	---
Woodward	1	1963	Combustion-Turbine	Gas	Peaking	0.2%(B)	12.0	12.0
McClain (D)	1	2001	Combined Cycle	Gas	Base Load	75.9%	355.5	355.5
Total Generating Capability (all stations)								6,121.9

(A) 2005 Capacity Factor = 2005 Net Actual Generation / (2005 Net Maximum Capacity (Nameplate Rating in MW's) x Period Hours (8,760 Hours)).
(B) Peaking units, which are used when additional capacity is required, are also necessary to meet the SPP reserve margins.
(C) These units are currently inactive.
(D) OG&E owns a 77 percent interest in the 520 MW McClain Plant.

At December 31, 2005, OG&E's transmission system included: (i) 28 substations with a total capacity of approximately 7.7 million kilo Volt-Amps ("kVA") and approximately 3,969 structure miles of lines in Oklahoma; and (ii) two substations with a total capacity of approximately 1.9 million kVA and approximately 252 structure miles of lines in Arkansas. OG&E's distribution system included: (i) 334 substations with a total capacity of approximately 10.0 million kVA, 22,653 structure miles of overhead lines, 2,054 miles of underground conduit and 8,299 miles of underground conductors in Oklahoma; and (ii) 37 substations with a total capacity of approximately 1.6 million kVA, 1,896 structure miles of overhead lines, 257 miles of underground conduit and 478 miles of underground conductors in Arkansas.

At December 31, 2005, Enogex and its subsidiaries owned: (i) approximately 8,300 miles of intrastate gas gathering and transportation pipelines in Oklahoma and Texas; (ii) 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 (iii) six operating natural gas processing plants with a total inlet capacity of 738 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	2005 Inlet Volumes (MMcfd)	2005 Inlet Capacity (MMcfd)
Calumet	1969	Lean Oil	Gas	109	250
Canute	1996	Cryogenic Refrigeration	Gas	50	60
Cox City	1994	Cryogenic Refrigeration	Gas	159	180
Harrah	1994	Cryogenic Refrigeration	Gas	24	38
Thomas	1981	Cryogenic Refrigeration	Gas	80	150
Wetumka	1983	Cryogenic Refrigeration	Gas	37	60
				459	738

During the three years ended December 31, 2005, the Company's gross property, plant and equipment additions were approximately $864.1 million and gross retirements were approximately $226.3 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 14.0 percent of total property, plant and equipment at December 31, 2005.

Item 3. Legal Proceedings.

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies. Management consults with legal counsel and other appropriate experts to assess the claim. If in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. Except as set forth below and in Notes 14 and 15 of Notes to Consolidated Financial Statements, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's 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. No action has been taken in this case for more than eight years and, for this reason, OG&E is now treating this case as closed.

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 was held March 17 - 18, 2005. A ruling in this case by the special master was received in May 2005 which dismissed OG&E and all Enogex parties named in these proceedings. This ruling has been appealed to the District Court of Wyoming. An oral argument on this appeal to the District Court was made on December 9, 2005 but there is no ruling in this case to date. The Company intends to vigorously defend this action. At this time, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

3. *Will Price (Price I)* – On September 24, 1999, various subsidiaries of 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 was held April 1, 2005. The Company intends to vigorously defend this action. At this time, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

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 was held April 1, 2005. The Company intends to vigorously defend this action. At this time, the Company is unable to provide

an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

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 Products, 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 Corp., Belvan Limited Partnership and Todd Ranch Limited Partnership ("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 Central Oklahoma Oil and Gas Corp. ("COOG"). In 1999 a dispute arose as to whether the natural gas deliverability for the Stuart Storage Facility was being provided to Enogex by COOG and these issues were submitted to arbitration in the fourth quarter of 2001 resulting in an arbitration award against COOG and in favor of Enogex in the amount of approximately $23.3 million (the "COOG Judgment").

In 2002, Enogex exercised the asset purchase option provided in the Agreement and title to the Stuart Storage Facility was transferred to Enogex. In addition, under a related transaction, Natural Gas Storage Corporation ("NGSC"), an affiliate of COOG, went into default relating to a $12 million secured loan ("NGSC Loan") with the Company.

In 2002, a legal proceeding was filed by COOG and NGSC against the Company and Enogex in Texas – Natural Gas Storage Corporation and Central Oklahoma Oil and Gas Corp. v. OGE Energy Corp. and Enogex, Case No. 2002-38894; District Court of Harris County, Texas. COOG and NGSC stated a claim for declaratory judgment and breach of contract, asserting that NGSC was not obligated to make payments on the NGSC Loan. The Company objected to being sued in Texas based on lack of jurisdiction over the Company. Enogex responded to the allegations, asserting that the disputed issues have already been properly determined by the Arbitration Panel and, therefore, such action was improper. In 2003, the Texas Court granted Enogex's request for arbitration. In 2004, COOG, NGSC, Enogex and the Company submitted remaining issues to a second arbitration panel. The arbitration panel rendered a decision in the Company's favor for approximately $5.0 million related to the outstanding NGSC Loan (the "NGSC Judgment"). After the arbitration award, the plaintiffs, in the pending Texas action, amended the petition and moved to dismiss Enogex from the suit. The court granted the dismissal by order dated January 26, 2005. On September 30, 2005, an order was entered by the Texas Court disposing of the remaining and entire Texas action based on a lack of jurisdiction.

In 2003, the Company and Enogex brought separate complaints in the Western District of Oklahoma Federal Court 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. The Company and Enogex each stated claims for fraudulent transfer and breach of fiduciary duty. A jury trial was held in 2004 and the jury ruled in favor of the Company and Enogex for approximately $6.6 million ("Thrash Fraudulent Transfer Judgment"). In April 2005, the defendants filed an appeal in the Tenth Circuit Court of Appeals and on September 14, 2005, the defendants posted a cash bond for approximately $6.9 million to stay the execution of the Thrash Fraudulent Transfer Judgment pending appeal. On December 30, 2005, the parties reached a settlement of the Thrash Fraudulent Transfer Judgment, the COOG Judgment, the NGSC Judgment and related matters. The individual defendants agreed to pay approximately $5.2 million (the "Settlement Amount") from the cash bond paid into the appeal court. In addition, the parties agreed to dismiss the pending appeal of the Thrash Fraudulent Transfer Judgment to the Tenth Circuit. The Settlement Amount has been accounted for as a gain contingency and will be recognized in the Company's financial statements when the Settlement Amount has been received which is expected in the first quarter of 2006. Upon payment of the Settlement Amount, the Company will consider these matters closed.

7. OG&E was sued by Kaiser-Francis Oil Company in District Court, Blaine County, Oklahoma. This case has been pending for more than 13 years. Plaintiff alleged that 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 sought $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 was permitted to amend its petition to include a claim based on theories of tort. Specifically, Plaintiff alleged that OG&E engaged in tortious conduct by, among other things, falsifying documents, sponsoring false testimony and putting forward legal defenses, which were known by OG&E to be without merit. If successful, Plaintiff believed that these

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theories could give Plaintiff a basis to seek punitive damages. This lawsuit was stayed from June 2002 through February 2005 during the appeal of a similar case filed by Kaiser-Francis in Grady County, Oklahoma.

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

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

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

9. On March 8, 2005, Enogex was served with a putative class action filed by G.M. Oil Properties, Inc. in the District Court of Comanche County, Oklahoma. The petition alleges that Enogex exercises a monopoly power with respect to its gathering facilities within the state of Oklahoma. The petition further alleges that, due to the alleged monopoly power, Enogex has caused damage to the plaintiff and other small gas producers and marketers. A settlement of this case has been reached with the named plaintiffs and the case brought by the named plaintiffs will be dismissed with prejudice. Pursuant to the settlement, a certain segment of gathering pipeline will be sold to G.M. Oil Properties with the Company recognizing the resulting gain of less than $0.1 million.

10. On July 22, 2005, Enogex, Products and Gathering along with certain other unaffiliated co-defendants were served with a purported class action which had been filed on February 7, 2005 by Farris Buser and other named plaintiffs in the District Court of Canadian County, Oklahoma. The plaintiffs' own royalty interests in certain oil and gas producing properties and allege they have been under-compensated by the named defendants, including the Enogex companies, relating to the sale of liquid hydrocarbons recovered during the transportation of natural gas from the plaintiffs' wells. The plaintiffs' assert breach of contract, implied covenants, obligation, fiduciary duty, unjust enrichment, conspiracy and fraud causes of action and claim actual damages in excess of $10,000, plus attorneys' fees and costs, and punitive damages in excess of $10,000. The Enogex companies filed a motion to dismiss which was granted on November 18, 2005, subject to the plaintiffs' right to conduct discovery and the possible re-filing of their allegations in the petition against Enogex companies. The court-established re-filing deadline has been extended by order of the court until May 17, 2006. On September 19, 2005, the co-defendants, BP America, Inc. and BP America Production Co., filed a cross claim against Products seeking indemnification and/or contribution from Products based upon the 1997 sale of a third party interest in one of Products natural gas processing plants. Based on its investigation to date, the Company believes these claims and cross claims in this lawsuit are without merit and intends to vigorously defend this case.

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 24, 2006:

Name	Age	Title

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

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

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

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

	2001 – 2005:	Chief Information Officer, Vice President – Information Technology – Varco International (oil and gas equipment company)
Scott Forbes	2005 – Present:	Controller and Chief Accounting Officer
	2003 – 2005:	Chief Financial Officer – First Choice Power (electric utility)
	2002 – 2005:	Senior Vice President and Chief Financial Officer – Texas New Mexico Power Company
	2001 – 2002:	Vice President – Chief Accounting and Information Officer Texas New Mexico Power Company (electric utility)
Donald R. Rowlett	2005 – Present:	Chief Accounting Policy Officer
	2001 – 2005:	Vice President and Controller
Deborah S. Fleming	2003 – Present:	Treasurer
	2001 – 2003:	Assistant Treasurer – Williams Cos. Inc. (energy company)
Jerry A. Peace	2004 – Present:	Chief Risk and Compliance Officer
	2002 – 2004:	Chief Risk Officer
	2001 – 2002:	Director, Options Trading – Enogex Inc.
	2001:	Director, Structured Services – Enogex Inc.

PART II

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

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.

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	**$ 0.3325**	**$ 27.59**	**$ 25.15**
Second Quarter	**0.3325**	**29.22**	**26.11**
Third Quarter	**0.3325**	**30.60**	**27.74**
Fourth Quarter	**0.3325**	**28.60**	**24.41**

2006	Dividend Paid	Price High	Price Low
First Quarter (through January 31)	$ 0.3325	**$ 27.51**	**$ 26.60**

The number of record holders of the Company's Common Stock at January 31, 2006, was 26,335. The book value of the Company's Common Stock at January 31, 2006, was $15.22.

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

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
1/1/05 – 1/31/05	77,500	$25.84	N/A	N/A
2/1/05 – 2/28/05	65,000	$25.90	N/A	N/A
3/1/05 – 3/31/05	26,100	$26.69	N/A	N/A
4/1/05 – 4/30/05	73,800	$26.96	N/A	N/A
5/1/05 – 5/31/05	17,800	$27.77	N/A	N/A
6/1/05 – 6/30/05	38,600	$28.35	N/A	N/A
7/1/05 – 7/31/05	66,500	$29.66	N/A	N/A
8/1/05 – 8/31/05	37,700	$28.81	N/A	N/A
9/1/05 – 9/30/05	18,700	$29.01	N/A	N/A
10/1/05 – 10/31/05	65,100	$26.30	N/A	N/A
11/1/05 – 11/30/05	13,300	$25.39	N/A	N/A
12/1/05 – 12/31/05	16,400	$27.04	N/A	N/A

N/A – not applicable

Item 6. Selected Financial Data.

HISTORICAL DATA

	2005	2004	2003	2002	2001
Selected Financial Data *(In millions, except per share data)*					
Operating revenues	**$ 5,948.2**	$ 4,904.4	$ 3,757.4	$ 2,991.8	$ 3,036.7
Cost of goods sold	**4,963.1**	3,963.1	2,841.6	2,105.7	2,172.0
Gross margin on revenues	**985.1**	941.3	915.8	886.1	864.7
Other operating expenses	**654.6**	637.5	617.9	659.5	599.2

Operating income	**330.5**	303.8	297.9	226.6	265.5
Other income	**0.2**	11.8	2.0	2.9	1.9
Other expense	**6.0**	5.1	7.6	4.2	4.2
Net interest expense	**86.8**	85.9	91.0	103.4	117.2
Income tax expense	**71.8**	77.1	70.8	43.2	52.9
Income from continuing operations	**166.1**	147.5	130.5	78.7	93.1
Income from discontinued operations, net of tax	**44.9**	6.0	4.7	12.1	7.5
Cumulative effect on prior years of change in accounting principle, net of tax of $3.4	**---**	---	(5.4)	---	---
Net income	**$ 211.0**	$ 153.5	$ 129.8	$ 90.8	$ 100.6
Basic earnings (loss) per average common share					
Income from continuing operations	**$ 1.84**	$ 1.67	$ 1.60	$ 1.01	$ 1.19
Income from discontinued operations, net of tax	**0.50**	0.07	0.06	0.15	0.10
Loss from cumulative effect of accounting change, net of tax	**---**	---	(0.07)	---	---
Net income	**$ 2.34**	$ 1.74	$ 1.59	$ 1.16	$ 1.29
Diluted earnings (loss) per average common share					
Income from continuing operations	**$ 1.83**	$ 1.66	$ 1.59	$ 1.01	$ 1.19
Income from discontinued operations, net of tax	**0.49**	0.07	0.06	0.15	0.10
Loss from cumulative effect of accounting change, net of tax	**---**	---	(0.07)	---	---
Net income	**$ 2.32**	$ 1.73	$ 1.58	$ 1.16	$ 1.29
Dividends declared per share	**$ 1.33**	$ 1.33	$ 1.33	$ 1.33	$ 1.33

HISTORICAL DATA (Continued)

	2005	2004	2003	2002	2001
SELECTED FINANCIAL DATA *(In millions, except per share data)*					
Long-term debt	**$ 1,350.8**	$ 1,424.1	$ 1,436.1	$ 1,501.9	$ 1,526.3
Total assets	**$ 4,898.9**	$ 4,802.9	$ 4,560.4	$ 4,247.5	$ 4,118.0
CAPITALIZATION RATIOS (A)					
Stockholders' equity	**50.46%**	47.44%	45.56%	39.58%	40.54%
Long-term debt	**49.54%**	52.56%	54.44%	60.52%	59.46%
RATIO OF EARNINGS TO FIXED CHARGES (B)					
Ratio of earnings to fixed charges	**3.46**	3.32	3.08	2.10	2.15

(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 (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 related services for 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, 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. In October 2005, Enogex sold its interest in Enogex Arkansas Pipeline Corporation ("EAPC"), through which it had held a controlling interest in Ozark Gas Transmission, L.L.C. ("OGT"), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. The Company received approximately $177.4 million cash proceeds and recognized an after tax gain of approximately $36.7 million from the sale of this business in the fourth quarter. Enogex used approximately $31.9 million of the proceeds to repay principal and accrued interest on long-term debt and approximately $46.7 million to pay taxes associated with EAPC. The balance of the proceeds of approximately $98.8 million will be used to invest, over time, in strategic assets to diversify its asset base. Also, during the third quarter of 2005, Enogex Compression Company, LLC ("Enogex Compression") sold it majority interest in Enerven Compression Services, LLC ("Enerven"), a joint venture focused on the rental of natural gas compression assets. The EAPC and Enerven businesses have been reported as discontinued operations in the Company's Consolidated Financial Statements and are discussed further in Note 4 of Notes to Consolidated Financial Statements.

Executive Overview

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. As explained below, 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 weather-normalized basis, an annual total return in the top third of its peer group, dividend growth and maintenance of strong credit ratings.

OG&E has been focused on its Customer Savings and Reliability Plan, which provides for increased investment at the utility to improve reliability and meet load growth, replace infrastructure equipment and deploy newer technology that improves operational and environmental performance. As part of this plan, OG&E purchased a 77 percent interest in the 520 megawatt ("MW") natural gas-fired combined cycle NRG McClain Station (the "McClain Plant") in July 2004. Capacity payment savings from reduced cogeneration payments and fuel savings from the McClain Plant will be utilized to help mitigate the price increases associated with these investments. In 2005 OG&E filed a rate case to recover, among other things, its investment in, and the operating expenses of, the McClain Plant. An order was issued by the OCC on December 12, 2005 providing for a rate increase of approximately $42.3 million and OG&E implemented the new electric rates in January 2006. For additional information regarding the McClain Plant acquisition, the new electric rates and related regulatory matters, see Note 15 of Notes to Consolidated Financial Statements.

Enogex 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 and Rocky Mountain markets. Also, in 2005, Enogex's marketing business implemented a refocused strategy that seeks to minimize the amount of capital employed and to complement better the natural gas pipeline business. Enogex's improved financial performance and increased flexibility from the reduction of its long-term debt has enabled Enogex to begin to contribute to funding the Company's dividend. As discussed above, during 2005, Enogex sold its interests in EAPC and Enerven and will continue to review its asset portfolio and seek to divest underperforming or non-strategic assets.

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, 2005, OG&E and Enogex represented approximately 66 percent and 32 percent, respectively, of the Company's consolidated assets. The remaining two 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 MW's of contracts with qualified cogeneration facilities ("QF") and small power production producers' ("QF contracts") that will expire at the end of 2007, unless extended by OG&E. In addition, effective September 1, 2004, OG&E entered into a new 15-year power sales agreement for 120 MW's with PowerSmith Cogeneration Project, L.P. 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 as well as wind generation facilities.

Enogex initiated a program in 2002 to improve its financial profile and performance. Since January 1, 2002, Enogex has completed significant sales transactions, reduced debt, reduced its number of employees, 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 from 2003 to 2005 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 2006, the Company expects to continue to focus on improving operational efficiencies and profitable growth at OG&E and redeploying capital in expansion projects at Enogex. Across all business units, the Company continues to pursue a disciplined approach to continuous improvement and continues to improve efficiency of operations in enterprise-wide services to operate business units at reduced costs.

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

Forward-Looking Statements

Except for the historical statements contained herein, the matters discussed in the following discussion and analysis, including the discussion in "2006 Outlook", are forward-looking statements that are subject to certain risks, uncertainties and assumptions. Such forward-looking statements are intended to be identified in this document by the words "anticipate", "believe", "estimate", "expect", "intend", "objective", "plan", "possible", "potential", "project" and similar expressions. Actual results may vary materially. Factors that could cause actual results to differ materially include, but are not limited to: general economic conditions, including the availability of credit, actions of rating agencies and their impact on capital expenditures; the Company's ability and the ability of its subsidiaries to obtain financing on favorable terms; prices of electricity, coal, 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; availability and prices of raw materials; federal or state legislation and regulatory decisions and initiatives that affect cost and investment recovery, have an impact on rate structures or affect the speed and degree to which competition enters the Company's markets; environmental laws and regulations that may impact the Company's operations; changes in accounting standards, rules or guidelines; creditworthiness of suppliers, customers and other contractual parties; 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 including Risk Factors to the Company's Form 10-K for the year ended December 31, 2005.

Overview

Summary of Operating Results

2005 compared to 2004. The Company reported net income of approximately $211.0 million, or $2.32 per diluted share, as compared to approximately $153.5 million, or $1.73 per diluted share, for the years ended December 31, 2005 and 2004, respectively. The increase in net income during 2005 as compared to 2004 was primarily due to:

- OG&E reported net income of approximately $129.7 million, or $1.43 per diluted share of the Company's common stock, as compared to approximately $107.6 million, or $1.22 per diluted share, during 2005 and 2004, respectively;
- Enogex's operations, including discontinued operations, reported net income of approximately $89.8 million, or $0.99 per diluted share of the Company's common stock, as compared to

approximately $60.7 million, or $0.69 per diluted share, during 2005 and 2004, respectively; and

- a net loss at the holding company of approximately $8.5 million, or $0.10 per diluted share, during 2005 as compared to a net loss of approximately $14.8 million, or $0.18 per diluted share, during 2004 reflecting lower net interest expense of approximately $9.6 million partially offset by a lower income tax benefit of approximately $3.8 million.

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:

- 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, during 2004 and 2003, respectively;
- 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, during 2004 and 2003, respectively; and
- a net loss at the holding company of approximately $14.8 million, or $0.18 per diluted share, during 2004 as compared to a net loss of approximately $12.5 million, or $0.16 per diluted share, during 2003 reflecting 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.

Regulatory Matters

Gas Transportation and Storage Agreement

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

On July 14, 2005, the OCC issued an order in this case approving a $41.9 million annual recovery. The OCC order disallowed the recovery by OG&E of the amount that Enogex charges OG&E for the cost of fuel used, or otherwise unaccounted for, in providing natural gas transportation and storage service to OG&E. Over the last three years, this amount has ranged from $1.2 million to $3.7 million annually. This amount was approximately $1.2 million in 2005 and is projected to be approximately $0.5 million in 2006. The OCC's order required OG&E to refund to its Oklahoma customers the difference between the amounts collected from such customers in the past based on an annual rate of $46.8 million for gas transportation and storage services and the $41.9 million annual rate authorized by the OCC's order. Based on the order, OG&E's refund obligation was approximately $8.8 million. OG&E began refunding this obligation in September 2005 through its automatic fuel adjustment clause. The balance of the refund obligation was approximately $6.0 million at December 31, 2005. For further information, see Note 15 of Notes to Consolidated Financial Statements.

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

OG&E Oklahoma Rate Case Filing

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

On September 12, 2005, several parties filed responsive testimony reflecting various positions on the issues related to this case. In particular, the testimony of the OCC Staff recommended that OG&E be entitled a rate increase of

approximately $13.0 million, one-seventh the amount requested by OG&E in its May 20, 2005 application. The recommendations in the testimony of the Attorney General's office and the Oklahoma Industrial Energy Consumers recommended a rate decrease of approximately $24 million and $31 million, respectively. Hearings in the rate case began on October 10, 2005 and concluded on October 24, 2005. On November 3, 2005, the Referee appointed by the OCC for this proceeding issued a report recommending an estimated rate increase of approximately $42 million for OG&E. On December 12, 2005, the OCC issued an order providing for a $42.3 million increase in rates and a 10.75 percent return on equity, based on a capital structure consisting of 55.7 percent equity and 44.3 percent debt. The new rates became effective in January 2006. Also included in the order, among other things, are new depreciation rates effective January 2006 and a provision which modified OG&E's mechanism for the recovery of over or under recovered fuel costs from its customers to allow interest to be applied to the over or under recovery. For further information regarding this rate case, see Note 15 of Notes to Consolidated Financial Statements.

Coal Shipment Disruption

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

Potential New Enogex Project

On November 4, 2005, Enogex announced that it had entered into a letter of intent with El Paso Corporation ("El Paso") that is designed to accelerate El Paso's Continental Connector Project. The letter of intent contemplates arrangements by which El Paso or an affiliate would execute an initial lease of up to 750,000 decatherms per day ("Dth/day") of capacity on the Enogex pipeline system, with an option to expand up to 1.5 million Dth/day, so that the leased Enogex pipeline capacity would become an integral part of the Continental Connector Project. The letter of intent also contemplates a commitment by Enogex to secure up to 500,000 Dth/day of capacity subscriptions for the project. These arrangements would significantly reduce the amount of new mainline construction required for the project, resulting in less environmental disturbance and an earlier in-service target date of winter 2007-2008.

Under the letter of intent, the Continental Connector Project will use existing or expanded El Paso pipeline systems to transport capacity-constrained natural gas from Rocky Mountain and mid-continent supply regions to Custer, Oklahoma. At Custer, this gas and local mid-continent production will be transported on existing and expanded Enogex systems for Continental Connector under a long-term lease arrangement for re-delivery in the vicinity of Bennington, Oklahoma. From there, gas will be transported on new El Paso pipeline facilities through the Perryville, Louisiana, Hub to a termination with Tennessee and Southern Natural Pipelines at Pugh, Mississippi.

Enogex intends to work with El Paso to determine whether to advance this project. However, the commitments and obligations under the letter of intent are subject to various conditions, including definitive documentation and boards of directors' and regulatory approvals and there can be no assurance that the conditions will be satisfied. Pending satisfaction of these conditions, Enogex does not expect to incur material expenditures.

2006 Outlook

The Company's 2006 earnings guidance, excluding any gains on asset sales, and key assumptions are detailed below. The Company assumes approximately 91.2 million average diluted shares outstanding and cash flow from operations of between $320 and $330 million and an effective tax rate of 36.3 percent in its 2006 earnings guidance.

(In millions, except per share data)	Dollars	Diluted EPS
OG&E	\$124 - \$128	\$1.36 - \$1.40
Enogex	\$44 - \$48	\$0.48 - \$0.53
Holding Company	(\$7) – (\$9)	(\$0.08) – (\$0.10)
Total	\$159 - \$169	\$1.75 - \$1.85

Key assumptions for 2006 are:

OG&E

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

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.

Enogex

- Total Enogex gross margin of approximately \$272 million to \$279 million as compared to approximately \$258 million in 2005:
    - Transportation and storage gross margin contribution of approximately \$116 million as compared to approximately \$99 million in 2005:
        - The increase in gross margin is primarily attributable to a reduction in fuel losses; and
        - Approximately 80 percent of Enogex's transportation and storage contracts are firm contracts with revenues primarily from gas transportation contracts with utilities in Oklahoma and Arkansas and independent power producers in Oklahoma.
    - Gathering and processing gross margin contribution of approximately \$147 million to \$154 million as compared to approximately \$156 million in 2005:
        - Gross margin increase in Enogex's gathering and processing business in 2006 primarily due to continued efforts to increase margins from the negotiation of both new contracts and replacement contracts;
        - Volumes in Enogex's gathering and processing business remain flat from 2005;
        - Commodity spreads are \$1.95 to \$2.22 per Million British thermal unit ("MMBtu") in 2006 as compared to \$2.55 per MMBtu in 2005 and average natural gas liquids prices are \$0.94 to \$1.16 per gallon in 2006 as compared to \$1.02 per gallon in 2005; and
        - Enogex's gathering and processing business has 277 new well connections in 2006.
    - Marketing gross margin contribution of approximately \$9 million as compared to approximately \$3 million in 2005;
- Operating and maintenance expenses increase approximately \$7 million primarily due to increased employee and benefit costs;
- Interest expense remains relatively flat in 2006;
- Capital expenditures for investment in Enogex's pipeline system are approximately \$60 million in 2006;

and
- Funding for the Company’s pension plan may be up to $90 million in 2006, of which up to $7.4 million may be allocated to Enogex.

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 included in the 2006 earnings guidance.

Holding Company

- Funding for the Company’s pension plan may be up to $90 million in 2006, of which approximately $12.7 million may be allocated to the holding company; and
- Interest expense decreases slightly in 2006 due to lower levels of short-term debt offset by higher short-term interest rates.

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. 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, 2005, 2004 and 2003 and the Company’s consolidated financial position at December 31, 2005 and 2004. 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.

(In millions, except per share data)	**2005**	2004	2003
Operating income	**$ 330.5**	$ 303.8	$ 297.9
Net income	**$ 211.0**	$ 153.5	$ 129.8
Basic average common shares outstanding	**90.3**	88.0	81.8
Diluted average common shares outstanding	**90.8**	88.5	82.1
Basic earnings per average common share	**$ 2.34**	$ 1.74	$ 1.59
Diluted earnings per average common share	**$ 2.32**	$ 1.73	$ 1.58
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.

Operating Income (Loss) by Business Segment

(In millions)	**2005**	2004	2003
OG&E (Electric Utility)	**$ 232.2**	$ 192.3	$ 216.3
Enogex (Natural Gas Pipeline) (A)	**97.7**	112.6	82.1
Other Operations (B)	**0.6**	(1.1)	(0.5)
Consolidated operating income	**$ 330.5**	$ 303.8	$ 297.9

(A) Excludes discontinued operations. See “Enogex – Discontinued Operations” for a further discussion.
(B) Other Operations primarily includes unallocated corporate expenses and consolidating eliminations.

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

OG&E

(Dollars in millions)	2005	2004	2003
Operating revenues	**$ 1,720.7**	$ 1,578.1	$ 1,517.1
Cost of goods sold	**994.2**	914.2	837.3
Gross margin on revenues	**726.5**	663.9	679.8
Other operation and maintenance	**309.2**	301.9	294.8
Depreciation	**134.4**	122.7	121.8
Taxes other than income	**50.7**	47.0	46.9
Operating income	**232.2**	192.3	216.3
Other income (loss)	**(2.3)**	5.8	0.6
Other expense	**3.0**	2.7	3.2
Interest income	**2.6**	2.7	0.7
Interest expense	**47.2**	37.5	38.8
Income tax expense	**52.6**	53.0	60.2
Net income	**$ 129.7**	$ 107.6	$ 115.4
Operating revenues by classification			
Residential	**$ 663.6**	$ 611.4	$ 601.4
Commercial	**418.9**	389.9	372.5
Industrial	**355.6**	326.7	293.4
Public authorities	**173.1**	158.5	146.1
Sales for resale	**67.7**	57.0	57.7
Provision for refund on gas transportation and storage case	**(2.0)**	(6.9)	---
System sales revenues	**1,676.9**	1,536.6	1,471.1
Off-system sales revenues	**4.9**	0.8	4.1
Other	**38.9**	40.7	41.9
Total operating revenues	**$ 1,720.7**	$ 1,578.1	$ 1,517.1
MWH (A) sales by classification (in millions)			
Residential	**8.5**	7.9	8.2
Commercial	**6.0**	5.7	5.8
Industrial	**7.2**	7.0	6.8
Public authorities	**2.8**	2.7	2.7
Sales for resale	**1.5**	1.4	1.5
System sales	**26.0**	24.7	25.0
Off-system sales	**0.1**	0.1	0.1
Total sales	**26.1**	24.8	25.1
Number of customers	**745,493**	735,008	725,470
Average cost of energy per KWH (B) - cents			
Fuel	**3.011**	2.887	2.454
Fuel and purchased power	**3.300**	3.436	3.128
Degree days (C)			
Heating			
Actual	**3,159**	3,114	3,488
Normal	**3,631**	3,650	3,631
Cooling			
Actual	**2,163**	1,839	1,898
Normal	**1,911**	1,911	1,911

(A) Megawatt-hour.

(B) Kilowatt-hour

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

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

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

- warmer weather in OG&E's service territory, which increased the gross margin by approximately $33.4 million;
- price variance due to sales and customer mix and rate increases authorized in the OCC order in December 2005 that are included in the unbilled revenue calculation at December 31, 2005,

which increased the gross margin by approximately $13.2 million;

- new customer growth primarily in the residential and commercial sectors of OG&E's service territory, which increased the gross margin by approximately $6.6 million; and
- increased demand by industrial customers in OG&E's service territory, which increased the gross margin by approximately $5.8 million.

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

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component included in the cost-of-service for ratemaking, are passed through to OG&E's customers through automatic fuel adjustment clauses. The automatic fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC. The OCC, the APSC and the FERC have authority to review the appropriateness of gas transportation charges or other fees OG&E pays to Enogex.

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

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

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

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

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

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

Other expense includes, among other things, expenses from the losses on the sale of assets, miscellaneous charitable donations, expenditures for certain civic, political and related activities and miscellaneous deductions. Other expense was approximately $3.0 million in 2005 as compared to approximately $2.7 million in 2004, an increase of approximately $0.3 million or 11.1 percent which was primarily due to an increase of approximately $0.2 million in charitable contributions.

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

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

These increases in net interest expense were partially offset by:

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

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

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

These decreases in income tax expense were partially offset by higher pre-tax income for OG&E.

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

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

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

Fuel expense was approximately $645.1 million in 2004 as compared to approximately $544.4 million in 2003, an increase of approximately $100.7 million or 18.5 percent. The increase was primarily due to an increase in the average cost of fuel per kwh, primarily due to higher natural gas prices despite lower mwh sales. 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.

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

- increased outside services expense of approximately $18.1 million;

increased materials and supplies expense of approximately $2.0 million;

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- increased employee expenses of approximately $2.0 million; and
- increased liability insurance expense of approximately $0.9 million due to increased insurance premiums.

These increases in other operating and maintenance expenses were partially offset by lower salaries and wages expense of approximately $5.9 million and lower pension and benefit expense of approximately $6.4 million primarily due to more projects on which the costs are capitalized and are not being expensed currently.

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

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

Other expense was approximately $2.7 million in 2004 as compared to approximately $3.2 million in 2003, a decrease of approximately $0.5 million or 15.6 percent. The decrease in other expense was primarily due to realized losses of approximately $0.4 million from the sale of miscellaneous assets in 2003.

Net interest expense was approximately $34.8 million in 2004 as compared to approximately $38.1 million in 2003, a decrease of approximately $3.3 million or 8.7 percent. The decrease in net interest expense was primarily due to:

- an increase in interest income of approximately $1.7 million due to the interest portion of an income tax refund related to prior periods;
- a reduction in interest expense of approximately $0.7 million due to OG&E having lower average borrowing outstanding from the parent in 2004 as compared to 2003; and
- a reduction in interest expense of approximately $1.1 million due to an increase in the allowance for borrowed funds used during construction.

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

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

Enogex – Continuing Operations

(Dollars in millions)	**2005**	2004	2003
Operating revenues	**$ 4,369.1**	$ 3,421.7	$ 2,306.2
Cost of goods sold	**4,111.2**	3,143.6	2,070.2
Gross margin on revenues	**257.9**	278.1	236.0
Other operation and maintenance	**100.5**	97.3	87.4
Depreciation	**43.9**	44.0	40.9
Impairment of assets	**---**	7.8	9.2
Taxes other than income	**15.8**	16.4	16.4
Operating income	**97.7**	112.6	82.1
Other income	**0.8**	4.5	0.7
Other expense	**0.3**	0.3	1.6
Interest income	**2.9**	3.2	0.8
Interest expense	**32.6**	32.2	34.1
Income tax expense	**23.6**	33.1	19.8
Income from continuing operations	**$ 44.9**	$ 54.7	$ 28.1
New well connects	**272**	258	214

Gathered volumes – TBtud (A)	**1.01**	0.98	0.95
Incremental transportation volumes – TBtud	**0.45**	0.39	0.36
Total throughput volumes – TBtud	**1.46**	1.37	1.31
Natural gas processed – Mmcfd (B)	**518**	502	414
Natural gas liquids sold (keep-whole) – million gallons	**296**	263	207
Natural gas liquids sold (POL and fixed-fee) – million gallons	**15**	16	18
Total natural gas liquids sold – million gallons	**311**	279	225
Average sales price per gallon	**$ 0.847**	$ 0.720	$ 0.595

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

2005 compared to 2004. Enogex's operating income decreased approximately $14.9 million or 13.2 percent as compared to 2004. The decrease in operating income was primarily attributable to decreased gross margins of approximately $21.1 million in Enogex's marketing business and approximately $15.4 million in Enogex's transportation and storage business, which were partially offset by increased gross margins of approximately $16.3 million in Enogex's gathering and processing business. These decreases in operating income also were partially offset by an asset impairment charge of approximately $7.8 million recorded in 2004 with no similar item recorded in 2005.

Transportation and storage contributed approximately $99.1 million of Enogex's gross margin in 2005 as compared to approximately $114.5 million in 2004, a decrease of approximately $15.4 million or 13.4 percent. The gross margin decreased primarily due to:

- storage field gas losses, increased costs associated with natural gas purchases and sales, increased costs from electric compression, reduced fuel recoveries due to timing and system fuel volumes previously recorded in Enogex's transportation and storage business which are now being recorded in Enogex's gathering and processing business, which collectively reduced the gross margin by approximately $20.5 million; and
- reduced demand fees due to fewer overrun service charges with OG&E and the loss of firm contracts, which reduced the gross margin by approximately $2.1 million.

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

- increased crosshaul prices and volumes, which increased the gross margin by approximately $5.3 million; and
- increased commodity and interruptible revenues, which increased the gross margin by approximately $1.5 million.

Gathering and processing contributed approximately $156.1 million of Enogex's gross margin in 2005 as compared to approximately $139.8 million in 2004, an increase of approximately $16.3 million or 11.7 percent. Gathering gross

margins increased approximately $14.6 million or 17.2 percent in 2005 as compared to 2004. The gathering gross margin increased primarily due to:

- contractual fuel gains primarily due to higher natural gas prices and renegotiated contracts, which increased the gross margin by approximately $8.0 million;
- increased fuel over recoveries due to higher natural gas prices, 2005 fuel reserve and system fuel volumes previously recorded in Enogex's transportation and storage business which is now being recorded in Enogex's gathering and processing business, which increased the gross margin by approximately $4.2 million;
- higher volumes on the low pressure gathering systems, which increased the gross margin by approximately $2.2 million;
- higher volumes related to compression and dehydration, which increased the gross margin by approximately $2.2 million; and
- higher margin on natural gas sales reflective of opportunities in the marketplace, which increased the gross margin by approximately $2.1 million.

These increases in the gathering gross margin were partially offset by:

- higher cost of electricity in 2005, which reduced the gross margin by approximately $3.0 million; and
- lower volumes on the high pressure gathering systems, which reduced the gross margin by approximately $0.8 million.

Processing gross margins increased approximately $1.7 million or 3.1 percent in 2005 as compared to 2004 primarily due to:

- increased condensate margins primarily due to higher condensate prices, which increased the gross margin by approximately $3.0 million; and
- increased percent of liquids margins primarily due to higher natural gas prices, which increased the gross margin by approximately $1.4 million.

These increases in the processing gross margin were partially offset by decreased net keep-whole margins primarily due to higher natural gas prices, which reduced the gross margin by approximately $3.1 million.

Marketing contributed approximately $2.7 million of Enogex's gross margin in 2005 as compared to approximately $23.8 million in 2004, a decrease of approximately $21.1 million or 88.6 percent. The gross margin decreased primarily due to:

- less favorable market conditions and trading activity, which reduced the gross margin by approximately $13.0 million;
- a correction to the accounting procedure for park and loan transactions (natural gas storage transactions) in 2004, which reduced the gross margin by approximately $7.7 million (see Note 13 of Notes to Consolidated Financial Statements); and
- losses incurred related to Enogex's position on the Cheyenne Plains' transportation agreement, which reduced the gross margin by approximately $3.6 million.

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

- lower demand fees paid for storage services due to establishing new rates for the new storage season, which began April 1, 2004 which increased the gross margin by approximately $2.5 million; and
- gains in storage activity, which increased the gross margin by approximately $0.7 million.

Enogex's other operating and maintenance expenses were approximately $100.5 million in 2005 as compared to approximately $97.3 million in 2004, an increase of approximately $3.2 million or 3.3 percent. The increase in other operating and maintenance expenses was primarily due to:

- higher outside service costs related to business development projects in 2005, system software implementation in 2005 and work performed to maintain the integrity and safety of Enogex's pipeline of approximately $3.9 million; and

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- expenses related to a pipeline rupture in the second quarter 2005 of approximately $0.5 million.

These increases in other operating and maintenance expenses were partially offset by an uncollectible debt reserve of approximately $1.1 million recorded in 2004 with no similar reserve recorded in 2005

Impairment of assets was approximately $7.8 million ($4.8 million after tax) in 2004 as a result of recording an impairment charge during the third quarter of 2004. The impairment charge related to certain Enogex natural gas pipeline assets that served a particular customer's power plants pursuant to a transportation agreement that was terminated by the customer effective December 31, 2004. There were no impairments recorded in 2005.

Other income was approximately $0.8 million in 2005 as compared to approximately $4.5 million in 2004, a decrease of approximately $3.7 million or 82.2 percent. The decrease in other income was primarily due to a gain in 2004 of approximately $3.0 million from the sale of certain of Enogex's compression and processing assets in 2004 in addition to approximately $0.8 million received related to a bankruptcy settlement from one of Enogex's customers during the third quarter of 2004.

Net interest expense was approximately $29.7 million in 2005 as compared to approximately $29.0 million in 2004, an increase of approximately $0.7 million or 2.4 percent. The increase in net interest expense was primarily due to a decrease in interest income of approximately $0.8 million. The decrease in interest income reflects a decrease of $1.9 million due to the interest portion of an income tax refund related to prior periods which was received in 2004 with no similar activity recorded in 2005 partially offset by an increase of approximately $1.1 million in interest income from parent due to funds received from the sale of EAPC in October 2005.

Income tax expense was approximately $23.6 million in 2005 as compared to approximately $33.1 million in 2004, a decrease of approximately $9.5 million or 28.7 percent. The decrease in income tax expense was primarily due to:

- lower pre-tax income for Enogex; and
- a reduction in excess deferred taxes of approximately $3.2 million in 2005.

These decreases in income tax expense were partially offset by a decrease in Oklahoma state income tax credits of approximately $1.6 million in 2005 as compared to 2004.

For 2005, Enogex's net income, including the discontinued operations discussed below under the caption "Enogex – Discontinued Operations," was approximately $89.9 million as compared to approximately $60.7 million in 2004. During 2005, Enogex had an increase in net income of approximately $40.2 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:

- a gain on the sale of EAPC in October 2005 of approximately $36.7 million;
- income from discontinued operations of approximately $6.4 million; and
- a gain on the sale of Enerven in August 2005 of approximately $1.8 million.

These increases to net income were partially offset by a correction to the accounting procedure for park and loan transactions in 2004 of approximately $4.7 million.

During the year ended December 31, 2004, Enogex had an increase in net income of approximately $9.9 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:

- income from discontinued operations of approximately $6.0 million;
- 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 $1.0 million; and
- a settlement related to a customer bankruptcy of approximately $0.5 million.

These increases to net income were partially offset by:

- a net impairment charge of approximately $4.8 million.

2004 compared to 2003. Enogex's operating income from continuing operations in 2004 increased approximately $30.5 million or 37.1 percent as compared to 2003. Gross margins increased approximately $48.5 million in Enogex's gathering and processing business, which was partially offset by decreased gross margins of approximately $6.3 million in Enogex's transportation and storage business and approximately $0.1 million in Enogex's marketing business. The increase in operating income was also partially offset by higher operating expenses.

Transportation and storage contributed approximately $114.5 million of Enogex's gross margin in 2004 as compared to approximately $120.8 million in 2003, a decrease of approximately $6.3 million or 5.2 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;
- 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; and
- reduced fuel recoveries due to timing related to fuel recoveries, which reduced the gross margin by approximately $1.1 million.

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

- 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 $5.0 million; and
- 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.

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 $27.6 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 $20.9 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;
- 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 $97.3 million in 2004 as compared to approximately $87.4 million in 2003, an increase of approximately $9.9 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;
- higher uncollectibles expense of approximately $1.4 million due to miscellaneous accounts receivable items becoming over 180 days old; and
- higher legal expenses of approximately $0.6 million related to the Section 311 rate case and other litigation.

Depreciation expense was approximately $44.0 million in 2004 as compared to approximately $40.9 million in 2003, an increase of approximately $3.1 million or 7.6 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.

Other income was approximately $4.5 million in 2004 as compared to approximately $0.7 million in 2003, an increase of approximately $3.8 million. The increase in other income was primarily due to:

- a realized gain of approximately $3.0 million on the sale of certain of Enogex's compression and processing assets in 2004; and
- a bankruptcy settlement from one of Enogex's customers of approximately $0.8 million during the third quarter of 2004.

Other expense was approximately $0.3 million in 2004 as compared to approximately $1.6 million in 2003, a decrease of approximately $1.3 million or 81.3 percent. The decrease in other expense was primarily due to:

- realized losses of approximately $0.8 million from the sale of miscellaneous assets in 2003; and
- a loss from the dissolution of a lease in the third quarter of 2003 of approximately $0.7 million.

Net interest expense was approximately $29.0 million in 2004 as compared to approximately $33.3 million in 2003, a decrease of approximately $4.3 million or 12.9 percent. The decrease in net interest expense was primarily due to:

- an increase in interest income of approximately $1.9 million due to the interest portion of an income tax refund related to prior periods;
- a reduction in interest expense due to a reduction of long-term debt of approximately $1.3 million; and
- a reduction in commercial paper service fees of approximately $0.6 million due to the Company having a lower average commercial paper balance outstanding in 2004 as compared to 2003.

Income tax expense was approximately $33.1 million in 2004 as compared to approximately $19.8 million in 2003, an increase of approximately $13.3 million or 67.2 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 the recognition of additional Oklahoma state tax credits of approximately $1.8 million during 2004.

For 2004, Enogex's net income, including the discontinued operations discussed below under the caption "Enogex – Discontinued Operations," was approximately $60.7 million as compared to approximately $26.9 million in 2003. During the year ended December 31, 2004, Enogex had an increase in net income of approximately $9.9 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:

- income from discontinued operations of approximately $6.0 million;
- 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 $1.0 million; and
- a settlement related to a customer bankruptcy 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 $8.7 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;
- income from discontinued operations of approximately $4.7 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; and
- an income tax adjustment of approximately $1.7 million.

Enogex – Discontinued Operations

In April 2005, Enogex Compression received an unsolicited offer to buy its interest in Enerven, a joint venture focused on the rental of natural gas compression assets. After evaluating this offer, Enogex Compression sold its interest in Enerven for approximately $7.3 million in August 2005. Enogex Compression recognized an after tax gain of approximately $1.8 million related to the sale of this business.

Enogex regularly evaluates the long term stability, profitability and core competency of each of its businesses within the regulatory and market framework in which each business operates. Based on these evaluations, in September 2005, Enogex announced that it had entered into an agreement to sell its interest in EAPC, which held the NOARK interest. This sale was completed on October 31, 2005. The Company received approximately $177.4 million cash proceeds and recognized an after tax gain of approximately $36.7 million from the sale of this business in the fourth quarter. Enogex used approximately $31.9 million of the proceeds to repay principal and accrued interest on long-term debt and approximately $46.7 million to pay taxes associated with EAPC. The balance of the proceeds of approximately $98.8 million will be used to invest, over time, in strategic assets to diversify its asset base.

As a result of these sale transactions, Enogex Compression's interest in Enerven and Enogex's interest in EAPC, both of which were part of the Natural Gas Pipeline segment, have been reported as discontinued operations for the years ended December 31, 2005, 2004 and 2003 in the Consolidated Financial Statements. Results for these discontinued operations are summarized and discussed below.

(In millions)	**2005**	2004	2003
Operating revenues	**$ 69.3**	$ 78.3	$ 79.8
Cost of goods sold	**48.6**	54.5	61.2
Gross margin on revenues	**20.7**	23.8	18.6
Other operation and maintenance	**3.6**	4.2	4.9
Depreciation	**2.3**	3.5	3.5
Taxes other than income	**0.9**	1.1	1.2
Operating income	**13.9**	15.0	9.0
Other income	**66.2**	---	7.8
Other expense	**0.1**	0.6	1.4
Net interest expense	**3.8**	5.0	5.6
Income tax expense	**31.3**	3.4	5.1
Net income	**$ 44.9**	$ 6.0	$ 4.7

2005 compared to 2004. Gross margin decreased approximately $3.1 million or 13.0 percent in 2005 as compared to 2004. The decrease was primarily due to the sale of EAPC in the fourth quarter of 2005 in addition to an overpayment of natural gas purchases in a prior period that was recognized in 2004 with no similar item recorded in 2005, which reduced the gross margin by approximately $0.8 million.

Depreciation expense decreased approximately $1.2 million or 34.3 percent in 2005 as compared to 2004 primarily due to ceasing depreciation expense in September 2005 when EAPC was reported as a discontinued operation.

Other income increased approximately $66.2 million or 100.0 percent in 2005 as compared to 2004 primarily due to a pre-tax gain of approximately $63.3 million recognized in the fourth quarter of 2005 related to the sale of EAPC and a pre-tax gain of approximately $2.9 million recognized in the third quarter of 2005 related to the sale of Enerven.

Net interest expense decreased approximately $1.2 million or 24 percent in 2005 as compared 2004. The decrease was primarily due to the sale of EAPC in October 2005 and the use of a portion of the sale proceeds to repay long-term debt.

Income tax expense increased approximately $27.9 million in 2005 as compared to 2004. The increase was primarily due to taxes paid related to the sale of EAPC and Enerven.

2004 compared to 2003. Gross margin increased approximately $5.2 million or 28.0 percent in 2004 as compared to 2003. The increase was primarily due to:

- increased margins on the purchase and sale of natural gas, which increased the gross margin by approximately $4.3 million; and
- natural gas purchases in a prior period that was recognized in 2004 with no similar item recorded in 2003, which increased the gross margin by approximately $0.8 million.

Other operating expenses decreased approximately $0.8 million or 8.3 percent in 2004 as compared to 2003. The increase was primarily due to approximately $1.1 million of operating expenses recorded in 2003 related to the NuStar Joint Venture ("NuStar"), with no corresponding items recorded in 2004, due to the sale of NuStar in February 2003.

Other income decreased approximately $7.8 million or 100.0 percent in 2004 as compared to 2003 primarily due to a gain of approximately $5.3 million related to the sale of approximately 29 miles of transmission lines of the OGT pipeline in the first quarter of 2003.

Other expense decreased approximately $0.8 million or 57.1 percent in 2004 as compared to 2003 primarily due to 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 OGT pipeline that was attributable to the minority interest.

Financial Condition

The balance of Accounts Receivable was approximately $591.4 million and $484.5 million at December 31, 2005 and 2004, respectively, an increase of approximately $106.9 million or 22.1 percent. The increase was primarily due to an increase in OG&E's billings to its customers reflecting increased pass through of fuel costs resulting from significantly higher natural gas costs in December 2005 as compared to December 2004, colder weather and an increase in natural gas sales activity by Enogex in the fourth quarter of 2005.

The balance of Fuel Inventories was approximately $63.6 million and $89.0 million at December 31, 2005 and 2004, respectively, a decrease of approximately $25.4 million or 28.5 percent. The decrease is primarily due to a decrease in coal inventories resulting from decreased coal deliveries from the Powder River Basin due to ongoing railroad repairs as described in "Overview – Coal Shipment Disruption" and a decrease in natural gas storage capacity in OGE Energy Resources, Inc.'s ("OERI") business activities.

The balance of current Price Risk Management assets was approximately $116.5 million and $54.3 million at December 31, 2005 and 2004, respectively, an increase of approximately $62.2 million. The increase was primarily due to higher natural gas prices associated with OERI's short-term physical natural gas purchase transactions and associated financial contracts. The volume of OERI's short-term physical natural gas activity and associated financial contracts outstanding at December 31, 2005 remained substantially unchanged from December 31, 2004.

The balance of Gas Imbalance asset was approximately $32.0 million and $99.8 million at December 31, 2005 and 2004, respectively, a decrease of approximately $67.8 million or 67.9 percent. The Gas Imbalance asset is comprised of planned or managed imbalances related to OERI's 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 $15.7 million and $76.0 million at December 31, 2005 and 2004, respectively, a decrease of approximately $60.3 million or 79.3 percent. The decrease was due to a decrease in park and loan transactions during 2005 in OERI's business activities.

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

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

The balance of long-term Price Risk Management assets was approximately $9.0 million and $16.4 million at December 31, 2005 and 2004, respectively, a decrease of approximately $7.4 million or 45.1 percent. The decrease was primarily due to lower levels of activity associated with OERI's long-term physical natural gas transactions and associated financial contracts outstanding at December 31, 2005 partially offset by higher natural gas prices.

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

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

The balance of Short-Term Debt was approximately $30.0 million and $125.0 million at December 31, 2005 and 2004, respectively, a decrease of approximately $95.0 million or 76.0 percent. The decrease is primarily due to proceeds received from the sale of EAPC in October 2005 which were used to pay down the commercial paper balance partially offset by increasing daily operational needs of the Company.

The balance of Accounts Payable was approximately $510.4 million and $470.3 million at December 31, 2005 and 2004, respectively, an increase of approximately $40.1 million or 8.5 percent. The increase was primarily due to higher natural gas purchases in December 2005 as compared to December 2004 and timing of outstanding checks clearing the bank.

The balance of Accrued Taxes was approximately $67.1 million and $13.2 million at December 31, 2005 and 2004, respectively, an increase of approximately $53.9 million. The increase was primarily due to the increased income tax liability associated with the sale of EAPC.

The balance of current Price Risk Management liabilities was approximately $109.5 million and $38.7 million at December 31, 2005 and 2004, respectively, an increase of approximately $70.8 million. The increase was primarily due to higher natural gas prices associated with OERI's short-term physical natural gas sales transactions and associated financial contracts. The volume of OERI's short-term physical natural gas activity and associated financial contracts outstanding at December 31, 2005 remained substantially unchanged from December 31, 2004.

The balance of the Gas Imbalance liability was approximately $36.0 million and $16.3 million at December 31, 2005 and 2004, respectively, an increase of approximately $19.7 million. The Gas Imbalance liability is comprised of planned or managed imbalances related to OERI's business, referred to as park and loan transactions, and pipeline and natural gas liquids imbalances, which are operational imbalances. Operational imbalances were approximately $25.6 million and $13.9 million at December 31, 2005 and 2004, respectively, an increase of approximately $11.7 million or 84.2 percent due to higher natural gas storage imbalances from Enogex's storage fields. Park and loan transactions were approximately $10.2 million and $2.4 million at December 31, 2005 and 2004, respectively, an increase of approximately $7.8 million due to increased natural gas storage obligations from higher natural gas prices from OERI's business activities.

The balance of Accrued Pension and Benefit Obligations was approximately $234.5 million and $197.0 million at December 31, 2005 and 2004, respectively, an increase of approximately $37.5 million or 19.0 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 12 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

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 repurchased in 2004 in addition to the heat pump loans OG&E sold during 2002. The finance rate on the heat pump loans was based upon market rates and was reviewed and updated periodically. OG&E's heat pump loan balance was approximately $0.7 million and $1.3 million at December 31, 2005 and 2004, respectively, and is included in Accounts Receivable, Net in the 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, 2005 (in millions)	$	2.2
Note interest rate		5.25%
Base servicing fee rate (paid monthly)		0.375%
Trustee/custodian fees (paid quarterly) (in whole dollars)	$	1,250
Owner trustee fees (paid annually) (in whole dollars)	$	4,000
Sole director's fee (paid quarterly) (in whole dollars)	$	1,125
Loss exposure by securitization issue (in millions)	$	0.3

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") in November 1998. The Company terminated the MBP 19 program during the second quarter of 2005, with an effective date of January 31, 2005, and recorded a reduction in operating and maintenance expense of approximately $0.6 million related to this transaction. During the third and fourth quarters of 2005, the Company received approximately $1.4 million related to the dissolution of this program.

OG&E Railcar Leases

See Note 14 of Notes to Consolidated Financial Statements for a discussion of OG&E's railcar lease agreement.

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)	$ 661.0	$ 237.0	$ 424.0	N/A	N/A
Enogex capital expenditures and acquisitions	114.0	60.0	54.0	N/A	N/A
Other Operations capital expenditures	30.0	10.0	20.0	N/A	N/A
Total capital expenditures	805.0	307.0	498.0	N/A	N/A
Maturities of long-term debt	1,349.4	---	4.0	$ 400.0	$ 945.4
Interest payments on long-term debt	1,168.7	84.5	168.5	138.1	777.6
Pension funding obligations	189.9	90.0	70.7	29.2	N/A
Total capital requirements	3,513.0	481.5	741.2	567.3	1,723.0
Operating lease obligations					
OG&E railcars	56.3	4.3	7.9	7.5	36.6
Enogex noncancellable operating leases	4.6	3.3	1.0	0.2	0.1
Total operating lease obligations	60.9	7.6	8.9	7.7	36.7
Other purchase obligations and commitments					
OG&E cogeneration capacity payments	476.4	98.6	192.5	185.3	N/A
OG&E fuel minimum purchase commitments	832.5	184.3	359.0	202.4	86.8
Other	68.2	7.4	14.9	14.9	31.0
Total other purchase obligations and commitments	1,377.1	290.3	566.4	402.6	117.8
Total capital requirements, operating lease obligations and other purchase obligations and commitments	4,951.0	779.4	1,316.5	977.6	1,877.5
Amounts recoverable through automatic fuel adjustment clause (B)	(1,365.2)	(287.2)	(559.4)	(395.2)	(123.4)
Total, net	$ 3,585.8	$ 492.2	$ 757.1	$ 582.4	$ 1,754.1

(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. See Note 15 of Notes to Consolidated Financial Statements for a discussion of the completed proceedings at the OCC regarding OG&E's gas transportation and storage contract with Enogex.

2005 Capital Requirements and Financing Activities

Total capital requirements, consisting of capital expenditures, maturities of long-term debt, interest payments on long-term debt and pension funding obligations, were approximately $448.8 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 $453.1 million in 2005. Approximately $19.2 million of the 2005 capital requirements were to comply with environmental regulations. This compares to net capital requirements of approximately $840.0 million and net contractual obligations of approximately $4.3 million totaling approximately $844.3 million in 2004, of which approximately $7.8 million was to comply with environmental regulations. During 2005, 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) and proceeds from the sale of assets. 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 from 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.

Discontinued Operations

Also contributing to the liquidity of the Company has been the disposition of certain assets classified as discontinued operations in 2005. During 2005, these dispositions have generated net sales proceeds of approximately $184.7 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.

Long-term Debt Maturities

Maturities of the Company’s long-term debt during the next five years consist of $3.0 million in 2007; $1.0 million in 2008 and $400.0 million in 2010. There are no maturities of the Company’s long-term debt in years 2006 or 2009.

Interest Rate Swap Agreements

See Note 10 of Notes to Consolidated Financial Statements for a discussion of the Company’s interest rate swap agreements.

Treasury Lock Agreements

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

Future Capital Requirements

Capital Expenditures

The Company’s current 2006 to 2008 construction program includes continued investment in OG&E’s and Enogex’s assets. 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 $5.0 million of the Company’s capital expenditures budgeted for 2006 are to comply with environmental laws and regulations. OG&E plans to continue to invest in its electric system at a level consistent with 2005. These capital expenditures do not include any capital requirements associated with OG&E’s proposed wind power project pending approval from the OCC. OG&E has approximately 430 MW’s of QF contracts that will expire at the end of 2007, unless extended by OG&E. For one of these QF contracts, OG&E purchases 100 percent of electricity generated by the QF. For the other QF contract, OG&E can purchase up to 17 percent of electricity generated by the QF. In addition, effective September 1, 2004, OG&E entered into a new 15-year power purchase agreement for 120 MW’s with PowerSmith Cogeneration Project, L.P. (“PowerSmith”), in which OG&E purchases 100 percent of electricity generated by 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 as well as wind generation facilities.

Refinancing of Long-Term Debt

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

Pension and Postretirement Benefit Plans

During 2005, actual asset returns for the Company’s defined benefit pension plan were positively affected by growth in the equity markets; however, the growth in 2005 was not as strong as the growth in the equity markets in 2004. At December 31, 2005, approximately 59 percent of the pension plan assets are invested in listed common stocks with the balance invested in corporate debt and U.S. Government securities. In 2005, asset returns on the pension plan were approximately 6.20 percent as compared to approximately 12.51 percent in 2004.

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

Contributions to the pension plan decreased from approximately $69.0 million in 2004 to approximately $32.0 million in 2005. This decrease in pension plan funding in 2005 was due to the fact that in prior years additional amounts were contributed to the pension plan to maintain an adequate funded status. During 2006, the Company may contribute up to $90 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. Legislation is before Congress that if passed would change the funding requirements for defined benefit plans. The proposed legislation would generally provide employers less funding flexibility and require a higher funding level than required under current regulations. Management will continue to monitor the outcome of the legislation.

As discussed in Note 12 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 2005 and 2004, 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, 2005 and 2004 of approximately $88.9 million and $92.0 million, respectively. At December 31, 2005 and 2004, 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 $154.6 million and $123.3 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 $181.4 million and $156.6 million, respectively, at December 31, 2005 and 2004. The offset of this entry was an intangible asset and Accumulated Other Comprehensive Income, net of a deferred tax asset; therefore, this adjustment did not impact the results of operations in 2005 or 2004 and did not require a usage of cash and is therefore excluded from the 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	P2	A2	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 and/or development of projects, actions by rating agencies, inflation, changes in environmental laws or regulations, rate increases or decreases allowed by regulatory agencies, new legislation and market entry of competing electric power generators.

Future Sources of Financing

Management expects that internally generated funds, long and short-term debt and proceeds from the sales of common stock pursuant to the Company's Automatic Dividend Reinvestment and Stock Purchase Plan will be adequate over the next three years to meet anticipated cash needs. 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

See Note 11 of Notes to Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

Common Stock

See Note 7 of Notes to Consolidated Financial Statements for a discussion of the Company's common stock activity.

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, operating revenues for Enogex, natural gas purchases for Enogex, the allowance for uncollectible accounts receivable, the valuation of energy purchase and sale contracts 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 12 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 an increase in discount rates will reduce funding requirements to the plan. The following table indicates the sensitivity of the pension plans funded status to these variables.

	Change		Impact on Funded Status
Actual plan asset returns	+/-	5 percent	+/- $21.2 million
Discount rate	+/-	0.25 percent	+/- $18.6 million
Contributions	+	$10.0 million	+ $10.0 million
Expected long-term return on plan assets	+/-	1 percent	None

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 included in the 2006 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 legal counsel and other appropriate experts to assess the claim. If in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's consolidated financial statements.

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

OG&E and Enogex engage in cash flow and fair value hedge transactions to modify the rate composition of the debt portfolio. Enogex also engages in cash flow and fair value hedge transactions to manage commodity risk. 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, "Accounting for Derivative Instruments and Hedging Activities," as amended, 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 and 2005, 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 and treasury lock agreements relating to managing interest rate exposure on the debt portfolio or anticipated debt issuances to modify the interest rate exposure on fixed rate debt issues. These interest rate swaps and treasury lock agreements qualify as fair value or cash flow hedges under SFAS No. 133. The objective of the 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. The objective of the treasury lock agreements was to protect against the variability of future payments of interest expense of debt that was issued by OG&E in January 2006.

Electric Utility Segment

OG&E, as a regulated utility, is subject to the accounting principles prescribed by the 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.

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, 2005, if the estimated usage or price used in the unbilled revenue calculation were to increase or decrease by one percent, this would cause a change in the unbilled revenues recognized of approximately $0.4 million. At December 31, 2005 and 2004, Accrued Unbilled Revenues were approximately $41.8 million and $45.5 million, respectively. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

Customer balances are generally written off if not collected within six months after the final billing date. The allowance for uncollectible accounts receivable is calculated by multiplying the last six months of electric revenue by the provision rate. The provision rate is based on a 12-month historical average of actual balances written off. To the extent the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. At December 31, 2005, if the provision rate were to increase or decrease by 10 percent, this would cause a change in the uncollectible expense recognized of approximately $0.2 million. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the 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 $2.5 million and $2.7 million at December 31, 2005 and 2004, respectively.

Natural Gas Pipeline Segment

Operating revenues for transportation, storage, gathering and processing services for Enogex are recorded each month based on the current month's estimated volumes, 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 models to estimate the fair value of its energy contracts including derivatives that do not have an independent market price. At December 31, 2005, unrealized mark-to-market gains were approximately $5.7 million, which included approximately $0.7 million of unrealized mark-to-market gains that were calculated utilizing models. At December 31, 2005, 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

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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.

Natural gas inventory used in Enogex's business is recorded at the lower of cost or market. In order to minimize risk, OERI enters into contracts or hedging instruments to hedge the fair value of this inventory. OERI has elected not to designate inventory hedging contracts as fair value or cash flow hedges under SFAS No. 133. The fair value of the hedging instruments is 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 Enogex's natural gas inventory was approximately $35.7 million and $46.8 million at December 31, 2005 and 2004, respectively. 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 $1.2 million and $1.8 million at December 31, 2005 and 2004, 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 retail restructuring efforts in Oklahoma and Arkansas have been postponed for the time being, if such efforts were renewed, retail competition and the unbundling of regulated energy service could have a significant financial impact on the Company due to an impairment of assets, a loss of retail customers, lower profit margins and/or increased costs of capital. Any such restructuring could have a significant impact on the Company's consolidated financial position, results of operations and cash flows. The Company cannot predict when it will be subject to changes in legislation or regulation, nor can it predict the impact of these changes on the Company's consolidated financial position, results of operations or cash flows. The Company believes that the prices for electricity and the quality and reliability of the Company's service currently place us in a position to compete effectively in the energy market. These developments at the federal and state levels as well as pending regulatory matters affecting the Company are described in more detail in Note 15 of Notes to Consolidated Financial Statements.

Commitments and Contingencies

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits, claims made by third parties, environmental actions or the action of various regulatory agencies. Management consults with legal counsel and other appropriate experts to assess the claim. If in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. Management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows. See Note 14 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.

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

Risk Committees and Oversight

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

The Unregulated Business Unit Risk Management Committee is comprised primarily of business unit leaders within Enogex. This committee's purpose is to develop and maintain risk policies for Enogex, to provide oversight and guidance for existing and prospective Enogex business activities and to provide governance regarding compliance with Enogex risk policies. This group is authorized by and reports to the Risk Oversight Committee.

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

Risk Policies

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

Interest Rate Risk

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

Fair Value Hedges

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

On April 1, 2005, Enogex terminated two interest rate swap agreements (with a total notional amount of $200 million) and received approximately $0.2 million related to this transaction. Since inception of the Enogex interest rate swap agreements, which converted $200 million of 8.125 percent fixed rate debt due January 15, 2010 to a floating rate based upon the three and six month LIBOR, the Company has paid approximately $81.3 million in interest and has received

approximately $29.9 million related to these agreements. The effective interest rate until maturity will be approximately 7.67 percent on this long-term debt.

On September 1, 2005, the counterparty to OG&E's interest rate swap agreement exercised its right to change the termination date of the interest rate swap agreement from October 15, 2025 to October 15, 2005 in conjunction with the early redemption of long-term debt discussed in Note 10 of Notes to Consolidated Financial Statements. On October 17, 2005, OG&E received approximately $5.3 million related to the termination of its interest rate agreement of which approximately $1.7 million is related to interest received and approximately $3.6 million is related to canceling the interest rate swap agreement, which will be amortized over the life of the long-term debt OG&E issued in January 2006.

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

Cash Flow Hedges of Interest Rates

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

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

(Dollars in millions)	2006	2007	2008	2009	2010	Thereafter	Total	12/31/05 Fair Value
Fixed rate debt (A)								
Principal amount	$ ---	$ 3.0	$ 1.0	$ ---	$ 400.0	$ 810.0	$ 1,214.0	$ 1,273.4
Weighted-average interest rate	---	8.28%	7.07%	---	8.13%	6.05%	6.74%	---
Variable rate debt (B)								
Principal amount	---	---	---	---	---	$ 135.4	$ 135.4	$ 135.4
Weighted-average interest rate	---	---	---	---	---	2.62%	2.62%	---

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

The Company’s price risk management assets and liabilities as of December 31, 2005 were as follows:

(Dollars in millions)	Commodity	Notional Volume (MMBtu)	Maturity	Fair Value
TRADING				
Price Risk Management Assets				
Physical Purchases	Natural Gas	59.4	2006	$ 50.3
Physical Purchases	Natural Gas	2.7	2007	8.5
Total Physical Purchases				58.8
Physical Sales	Natural Gas	(53.6)	2006	22.4
Long Physical Options	Natural Gas	2.2	2006	0.1
Short Physical Options	Natural Gas	(54.9)	2006	3.3
Long Financial Swaps (excluding basis)	Natural Gas	3.1	2006	5.6
Short Financial Swaps (excluding basis)	Natural Gas	(5.7)	2006	1.0
Short Financial Options	Natural Gas	(2.0)	2006	0.8
Long Basis Positions	Natural Gas	42.7	2006	0.1
Short Basis Positions	Natural Gas	(49.8)	2006	32.2
Short Basis Positions	Natural Gas	(1.2)	2007	0.5
Total Short Basis Positions				32.7
				$ 124.8
TRADING				
Price Risk Management Liabilities				
Physical Purchases	Natural Gas	59.4	2006	$ 26.1
Physical Sales	Natural Gas	(53.6)	2006	37.4
Physical Sales	Natural Gas	(2.5)	2007	10.3
Total Physical Sales				47.7
Short Physical Options	Natural Gas	(54.9)	2006	1.3
Long Financial Swaps (excluding basis)	Natural Gas	3.1	2006	3.3
Short Financial Swaps (excluding basis)	Natural Gas	(5.7)	2006	13.5
Long Financial Options	Natural Gas	2.5	2006	1.3
Long Basis Positions	Natural Gas	42.7	2006	25.7
Long Basis Positions	Natural Gas	0.9	2007	0.4
Total Long Basis Positions				26.1
Short Basis Positions	Natural Gas	(49.8)	2006	0.4
				$ 119.7
NON-TRADING				
Price Risk Management Assets				
Long Financial Swaps (excluding basis)	Natural Gas	0.5	2006	$ 0.1
Long Basis Positions	Natural Gas	0.6	2006	0.1
Short Basis Positions	Natural Gas	(0.3)	2006	0.5
				$ 0.7
NON-TRADING				
Price Risk Management Liabilities				
Long Financial Swaps (excluding basis)	Natural Gas	0.5	2006	$ 0.3
Long Basis Positions	Natural Gas	0.6	2006	0.2
				$ 0.5

The valuation of the Company's price risk management assets and liabilities were 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.

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.

Trading Activities

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 VaR, which estimates the potential losses the trading activities could incur over a specified time horizon and confidence level. The VaR limit for the Company's trading activities, assuming a one day time horizon and 95 percent confidence level, is $1.5 million. These limits are designed to mitigate the possibility of trading activities having a material adverse effect on the Company's operating income.

A sensitivity analysis has been prepared to estimate the Company's exposure to market risk created by trading activities. 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. 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 result of this analysis, which may differ from actual results, is as follows for 2005.

(In millions)	Trading
Commodity market risk, net	$ 1.0

Non-Trading Activities

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 compensation received by the Company for operating some of its assets. To partially reduce non-trading commodity price risk, the Company hedges, through the utilization of derivatives and other forward transactions, the effects these market fluctuations have on the operating income of the Company. 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.

A sensitivity analysis has been prepared to estimate the Company's exposure to the market risk of the Company's 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. Quoted market prices are not available for all of the Company's non-trading positions, therefore, 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 result of this analysis, which may differ from actual results, is as follows for 2005.

(In millions)	Non-Trading
Commodity market risk, net	$ 6.9

The Company may designate certain derivative instruments for the purchase or sale of physical commodities, purchase or sale of electric power and fuel procurement as normal purchases and normal sales contracts under the provisions of SFAS No. 133. Normal purchases and normal sales contracts are not recorded in Price Risk Management assets or liabilities in the Consolidated Balance Sheets and earnings recognition is recorded in the period in which physical delivery of the commodity occurs. The Company applies normal purchases and normal sales to commodity contracts for the sale of natural gas liquids produced by its subsidiary, Enogex Products Corporation, to electric power contracts by OG&E and for fuel procurement by OG&E.

Credit Risk

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

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

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.

Currency Risk

The Company is exposed to currency risk from the Canadian dollar. This exposure is created by infrequent energy transactions entered into by OERI. Currency risk associated with this exposure is not material.

Item 8. Financial Statements and Supplementary Data.

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS

December 31 *(In millions)*	**2005**	2004
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 26.4**	$ 11.1
Accounts receivable, net	**591.4**	484.5
Accrued unbilled revenues	**41.8**	45.5
Fuel inventories	**63.6**	89.0
Materials and supplies, at average cost	**56.5**	53.2
Price risk management	**116.5**	54.3
Gas imbalances	**32.0**	99.8
Accumulated deferred tax assets	**14.3**	13.7
Fuel clause under recoveries	**101.1**	54.3
Recoverable take or pay gas charges	**4.9**	17.0
Prepayments and other	**25.1**	25.4
Current assets of discontinued operations	---	7.2
Total current assets	**1,073.6**	955.0
OTHER PROPERTY AND INVESTMENTS, at cost	**29.2**	31.4
PROPERTY, PLANT AND EQUIPMENT		
In service	**6,056.5**	5,811.0
Construction work in progress	**102.2**	110.4
Other	**3.1**	1.1
Total property, plant and equipment	**6,161.8**	5,922.5
Less accumulated depreciation	**2,594.4**	2,474.1
Net property, plant and equipment	**3,567.4**	3,448.4
In service of discontinued operations	---	151.4
Less accumulated depreciation	---	18.8
Net property, plant and equipment of discontinued operations	---	132.6

Net property, plant and equipment	**3,567.4**	3,581.0
DEFERRED CHARGES AND OTHER ASSETS		
Income taxes recoverable from customers, net	**32.8**	30.9
Intangible asset - unamortized prior service cost	**32.8**	38.0
Prepaid benefit obligation	**90.2**	92.7
Price risk management	**9.0**	16.4
McClain Plant deferred expenses	**24.9**	11.0
Unamortized loss on reacquired debt	**21.3**	21.0
Unamortized debt issuance costs	**8.1**	8.7
Other	**9.6**	12.1
Deferred charges and other assets of discontinued operations	---	4.7
Total deferred charges and other assets	**228.7**	235.5
TOTAL ASSETS	**$ 4,898.9**	$ 4,802.9

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

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS (Continued)

December 31 *(In millions)*	**2005**	2004
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 30.0**	$ 125.0
Accounts payable	**510.4**	470.3
Dividends payable	**30.1**	29.9
Customers' deposits	**47.8**	48.3
Accrued taxes	**67.1**	13.2
Accrued interest	**31.9**	32.8
Tax collections payable	**8.7**	7.2
Accrued vacation	**18.5**	17.9
Long-term debt due within one year	---	34.3
Price risk management	**109.5**	38.7
Gas imbalances	**36.0**	16.3
Provision for payments of take or pay gas	**8.9**	21.0
Accrued compensation	**21.5**	19.4
Other	**30.2**	27.3
Current liabilities of discontinued operations	---	9.6
Total current liabilities	**950.6**	911.2
LONG-TERM DEBT		
Long-term debt	**1,350.8**	1,359.1
Long-term debt of discontinued operations	---	65.0
Total long-term debt	**1,350.8**	1,424.1
COMMITMENTS AND CONTINGENT LIABILITIES (NOTE 14)		
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued pension and benefit obligations	**234.5**	197.0
Accumulated deferred income taxes	**807.1**	784.2
Accumulated deferred investment tax credits	**31.7**	36.8
Accrued removal obligations, net	**114.2**	122.2
Price risk management	**10.7**	3.5
Asset retirement obligation	**3.6**	1.1
Other	**19.9**	18.9
Deferred credits and other liabilities of discontinued operations	---	18.3
Total deferred credits and other liabilities	**1,221.7**	1,182.0
STOCKHOLDERS' EQUITY		
Common stockholders' equity	**715.5**	700.8
Retained earnings	**750.5**	659.8
Accumulated other comprehensive loss, net of tax	**(90.2)**	(75.0)
Total stockholders' equity	**1,375.8**	1,285.6
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 4,898.9**	$ 4,802.9

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 *(In millions)*		**2005**		2004
STOCKHOLDERS' EQUITY				
Common stock, par value $0.01 per share; authorized 125.0 shares; and outstanding 90.6 and 90.0 shares, respectively		**$ 0.9**		$ 0.9
Premium on capital stock		**714.6**		699.9
Retained earnings		**750.5**		659.8
Accumulated other comprehensive loss, net of tax		**(90.2)**		(75.0)
Total stockholders' equity		**1,375.8**		1,285.6
LONG-TERM DEBT				
SERIES	DATE DUE			
Senior Notes-OGE Energy Corp.				
5.00 %	Senior Notes, Series Due November 15, 2014	**100.0**		100.0
Unamortized discount		**(0.8)**		(0.9)
Senior Notes-OG&E				
7.125 %	Senior Notes, Series Due October 15, 2005	---		110.0
6.50 %	Senior Notes, Series Due July 15, 2017	**125.0**		125.0
Variable%	Senior Notes, Series Due October 15, 2025	---		114.0
6.65 %	Senior Notes, Series Due July 15, 2027	**125.0**		125.0
6.50 %	Senior Notes, Series Due April 15, 2028	**100.0**		100.0
6.50 %	Senior Notes, Series Due August 1, 2034	**140.0**		140.0
Other bonds-OG&E				
1.56% - 3.71%	Garfield Industrial Authority, January 1, 2025	**47.0**		47.0
1.80% - 3.70%	Muskogee Industrial Authority, January 1, 2025	**32.4**		32.4
1.74% - 3.63%	Muskogee Industrial Authority, June 1, 2027	**56.0**		56.0
Other long-term debt (NOTE 11)		**220.0**		---
Unamortized discount		**(1.4)**		(2.2)
Enogex Notes – Continuing Operations				
6.81% - 6.99%	Medium-Term Notes, Series Due 2005	---		34.3
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	**400.0**		200.0
Variable %	Medium-Term Notes, Series Due 2010	---		203.9
Unamortized swap monetization		**3.6**		4.9
Enogex Notes – Discontinued Operations				
7.15%	Medium-Term Notes, Series Due 2018	---		65.0
Total long-term debt		**1,350.8**		1,458.4
Less long-term debt due within one year		---		34.3
Total long-term debt (excluding long-term debt due within one year)		**1,350.8**		1,424.1
Total Capitalization		**$ 2,726.6**		$ 2,709.7

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)*	**2005**	2004	2003
OPERATING REVENUES			
Electric Utility operating revenues	**$ 1,720.7**	$ 1,578.1	$ 1,517.1
Natural Gas Pipeline operating revenues	**4,227.5**	3,326.3	2,240.3
Total operating revenues	**5,948.2**	4,904.4	3,757.4
COST OF GOODS SOLD (exclusive of depreciation shown below)			
Electric Utility cost of goods sold	**946.6**	864.7	792.7
Natural Gas Pipeline cost of goods sold	**4,016.5**	3,098.4	2,048.9
Total cost of goods sold	**4,963.1**	3,963.1	2,841.6
Gross margin on revenues	**985.1**	941.3	915.8
Other operation and maintenance	**398.8**	388.0	367.9
Depreciation	**186.1**	175.0	173.6
Impairment of assets	---	7.8	10.2
Taxes other than income	**69.7**	66.7	66.2
OPERATING INCOME	**330.5**	303.8	297.9
OTHER INCOME (EXPENSE)			
Other income	**0.2**	11.8	2.0
Other expense	**(6.0)**	(5.1)	(7.6)
Net other income (expense)	**(5.8)**	6.7	(5.6)
INTEREST INCOME (EXPENSE)			
Interest income	**3.5**	4.9	1.3
Interest on long-term debt	**(80.0)**	(69.4)	(70.1)
Interest expense – unconsolidated affiliate	---	(13.7)	(17.3)
Allowance for borrowed funds used during construction	**2.2**	1.7	0.5
Interest on short-term debt and other interest charges	**(12.5)**	(9.4)	(5.4)
Net interest expense	**(86.8)**	(85.9)	(91.0)
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	**237.9**	224.6	201.3
INCOME TAX EXPENSE	**71.8**	77.1	70.8
INCOME FROM CONTINUING OPERATIONS BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	**166.1**	147.5	130.5
DISCONTINUED OPERATIONS (NOTE 4)			
Income from discontinued operations	**76.2**	9.4	9.8
Income tax expense	**31.3**	3.4	5.1
Income from discontinued operations	**44.9**	6.0	4.7
INCOME BEFORE CUMULATIVE EFFECT OF CHANGE IN ACCOUNTING PRINCIPLE	**211.0**	153.5	135.2
CUMULATIVE EFFECT ON PRIOR YEARS OF CHANGE IN ACCOUNTING PRINCIPLE, net of tax of $3.4	---	---	(5.4)
NET INCOME	**$ 211.0**	$ 153.5	$ 129.8
BASIC AVERAGE COMMON SHARES OUTSTANDING	**90.3**	88.0	81.8
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**90.8**	88.5	82.1
BASIC EARNINGS (LOSS) PER AVERAGE COMMON SHARE			
Income from continuing operations	**$ 1.84**	$ 1.67	$ 1.60
Income from discontinued operations, net of tax	**0.50**	0.07	0.06
Loss from cumulative effect of accounting change, net of tax	---	---	(0.07)
NET INCOME	**$ 2.34**	$ 1.74	$ 1.59
DILUTED EARNINGS (LOSS) PER AVERAGE COMMON SHARE			
Income from continuing operations	**$ 1.83**	$ 1.66	$ 1.59
Income from discontinued operations, net of tax	**0.49**	0.07	0.06
Loss from cumulative effect of accounting change, net of tax	---	---	(0.07)
NET INCOME	**$ 2.32**	$ 1.73	$ 1.58
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)*	**2005**	2004	2003

BALANCE AT BEGINNING OF PERIOD	**$ 659.8**	$ 623.9	$ 604.7
ADD: Net income	**211.0**	153.5	129.8
Total	**870.8**	777.4	734.5
DEDUCT: Dividends declared on common stock	**120.3**	117.6	110.6
BALANCE AT END OF PERIOD	**$ 750.5**	$ 659.8	$ 623.9

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31 *(In millions)*	**2005**	2004	2003
Net income	**$ 211.0**	$ 153.5	$ 129.8
Other comprehensive income (loss), net of tax:			
Minimum pension liability adjustment [($30.0), ($21.2) and $23.8 pre-tax, respectively]	**(18.4)**	(13.0)	14.6
Deferred hedging gains (losses) [$4.7, ($1.1) and $1.5 pre-tax, respectively]	**2.9**	(0.7)	0.9
(Reversal of unrealized gains) unrealized gains on available-for-sale securities [($0.6) and $0.6 pre-tax, respectively]	**---**	(0.4)	0.4
Settlement and amortization of cash flow hedge [$0.5 and ($4.0) pre-tax, respectively]	**0.3**	(2.5)	---
Total other comprehensive income (loss), net of tax	**(15.2)**	(16.6)	15.9
Total comprehensive income	**$ 195.8**	$ 136.9	$ 145.7

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)*	**2005**	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income from continuing operations	**$ 166.1**	$ 147.5	$ 125.1
Adjustments to reconcile net income from continuing operations to net cash provided from operating activities			
Cumulative effect of change in accounting principle	**---**	---	5.4
Depreciation	**186.1**	175.0	173.6
Impairment of assets	**---**	7.8	10.2
Deferred income taxes and investment tax credits, net	**21.9**	50.5	114.3
Allowance for equity funds used during construction	**---**	(0.9)	---
Loss (gain) on sale of assets	**0.1**	(6.5)	(0.4)
Price risk management assets	**(62.6)**	(20.0)	(21.5)
Price risk management liabilities	**80.1**	9.5	12.3
Other assets	**(6.7)**	(27.9)	(8.3)
Other liabilities	**(2.1)**	11.0	0.4
Change in certain current assets and liabilities			
Accounts receivable, net	**(106.9)**	(136.5)	(45.4)
Accrued unbilled revenues	**3.7**	(7.5)	(9.8)
Fuel, materials and supplies inventories	**22.1**	52.5	(54.8)
Gas imbalance asset	**67.8**	(29.8)	(22.5)
Fuel clause under recoveries	**(46.8)**	(50.3)	10.7
Other current assets	**12.4**	10.0	(15.9)
Accounts payable	**40.1**	194.2	18.3

Customers' deposits	**(0.5)**	6.7	1.0
Accrued taxes	**53.9**	(4.5)	(1.1)
Accrued interest	**(0.9)**	(0.7)	(1.7)
Fuel clause over recoveries	**---**	(32.4)	32.4
Gas imbalance liability	**19.7**	(6.5)	0.6
Other current liabilities	**(1.2)**	11.9	19.4
Net Cash Provided from Operating Activities	**446.3**	353.1	342.3
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures (less allowance for equity funds used during construction)	**(298.7)**	(430.9)	(180.8)
Proceeds from sale of assets	**5.8**	9.2	6.4
Other investing activities	**0.1**	0.7	1.6
Net Cash Used in Investing Activities	**(292.8)**	(421.0)	(172.8)
CASH FLOWS FROM FINANCING ACTIVITIES			
Retirement of long-term debt	**(254.3)**	(206.2)	(29.0)
Increase (decrease) in short-term debt, net	**125.0**	(77.5)	(72.5)
Proceeds from long-term debt	**---**	186.0	---
Premium on issuance of common stock	**14.7**	62.5	171.3
Dividends paid on common stock	**(120.0)**	(114.6)	(98.6)
Net Cash Used in Financing Activities	**(234.6)**	(149.8)	(28.8)
DISCONTINUED OPERATIONS			
Net cash (used in) provided from operating activities	**(51.4)**	38.5	(7.4)
Net cash provided from (used in) investing activities	**147.9**	(0.8)	47.9
Net cash (used in) provided from financing activities	**(0.1)**	(21.4)	1.8
Net Cash Provided from Discontinued Operations	**96.4**	16.3	42.3
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**15.3**	(201.4)	183.0
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**11.1**	212.5	29.5
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 26.4**	$ 11.1	$ 212.5

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 related services for 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 significant intercompany transactions have been eliminated in consolidation.

The Electric Utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through Oklahoma Gas and Electric Company ("OG&E") and are subject to regulation by the Oklahoma Corporation Commission ("OCC"), the Arkansas Public Service Commission ("APSC") and the Federal Energy Regulatory Commission ("FERC"). OG&E was incorporated in 1902 under the laws of the Oklahoma Territory, is the largest electric utility in Oklahoma and its franchised service territory includes the Fort Smith, Arkansas area. 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. Prior to October 31, 2005, Enogex owned, through a 75 percent interest in the NOARK Pipeline System Limited Partnership ("NOARK"), a controlling interest in and operated Ozark Gas Transmission, L.L.C. ("OGT"), a FERC regulated interstate pipeline that extends from southeast Oklahoma through Arkansas to southeast Missouri. On October 31, 2005, Enogex sold its interest in Enogex Arkansas Pipeline Corporation ("EAPC"), which held the NOARK interest. Also, during the third quarter of 2005, Enogex Compression Company, LLC ("Enogex Compression") sold it majority interest in Enerven Compression Services, LLC

("Enerven"), a joint venture focused on the rental of natural gas compression assets. The EAPC and Enerven businesses have been reported as discontinued operations in the Company's Consolidated Financial Statements (see Note 4 for a further discussion).

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

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.

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

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

Income taxes recoverable from customers represent income tax benefits previously used to reduce 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." At December 31, 2005, the balance of income taxes recoverable from customers, net was approximately $32.8 million. The OCC authorized approximately $30.1 million of the $32.8 million regulatory asset to be included in OG&E's rate base for purposes of earning a return.

As a result of the acquisition of a 77 percent interest in the 520 megawatt ("MW") natural gas-fired combined cycle NRG McClain Station (the "McClain Plant") completed on July 9, 2004, and consistent with the 2002 agreed-upon settlement of an OG&E rate case (the "Settlement Agreement") with the OCC, OG&E had the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the acquisition and operation of the McClain Plant, consisting of the non-fuel operation and maintenance expenses, depreciation, cost of debt associated with the investment and ad valorem taxes. OG&E's rate case application included an estimate of $25.9 million related to the McClain Plant regulatory asset. At December 31, 2005, the actual incurred expenses included in the McClain Plant regulatory asset were approximately $24.9 million. Such costs will be recovered over a four-year time period as authorized in the OCC rate order beginning in January 2006. The OCC also authorized approximately $15.5 million of the $24.9 million regulatory asset to be included in OG&E's rate base for purposes of earning a return. See Note 15 for further information regarding this rate case.

Unamortized loss on reacquired debt is comprised of unamortized debt issuance costs related to the early retirement of OG&E's long-term debt. These amounts are being amortized over the term of the long-term debt which replaced the previous long-term debt. The unamortized loss on reacquired debt is not included in OG&E's rate base and does not otherwise earn a rate of return.

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

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

Accrued removal obligations represent asset retirement costs previously recovered from ratepayers for other than legal obligations. In accordance with SFAS No. 143, "Accounting for Asset Retirement Obligations," 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.

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

Management continuously monitors the future recoverability of regulatory assets. When in management's judgment future recovery becomes impaired, the amount of the regulatory asset is reduced or written off, as appropriate. If the Company were required to discontinue the application of SFAS No. 71 for some or all of its operations, it could result in writing off the related regulatory assets; the financial effects of which could be significant.

Use of Estimates

In preparing the 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, operating revenues for Enogex, natural gas purchases for Enogex, the allowance for uncollectible accounts receivable, the valuation of energy purchase and sale contracts 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 $55.0 million and $33.9 million at December 31, 2005 and 2004, 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 final billing 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 $3.7 million and $4.5 million at December 31, 2005 and 2004, respectively.

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

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 $19.1 million and $13.7 million for 2005 and 2004, respectively, based on the average cost of fuel purchased. The amount of fuel inventory was approximately $27.9 million and $42.2 million at December 31, 2005 and 2004, respectively.

Enogex

Natural gas inventory used in Enogex's business is recorded at the lower of cost or market. In order to minimize risk, OGE Energy Resources, Inc. ("OERI") enters into contracts or hedging instruments to hedge the fair value of this inventory. The fair value of the hedging instruments is recorded on the books of OERI as a Price Risk Management asset or liability with an offsetting gain or loss recorded in current earnings. OERI has elected not to designate inventory hedging contracts as fair value or cash flow hedges under SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," as amended. As part of its recurring business activity, OERI injects and withdraws natural gas under the terms of storage capacity contracts. The amount of Enogex's natural gas inventory was approximately $35.7 million and $46.8 million at December 31, 2005 and 2004, respectively.

Gas Imbalances

Gas imbalances occur when the actual amounts of natural gas delivered from or received by Enogex'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. Enogex values all imbalances at an average of current market indices applicable to Enogex's operations, not to exceed net realizable value. Also, included in Gas Imbalances on the Consolidated Balance Sheets are planned or managed imbalances related to OERI's business, referred to as park and loan transactions. Park and loan assets were approximately $15.7 million and $76.0 million, respectively, at December 31, 2005 and 2004 and park and loan liabilities were approximately $10.2 million and $2.4 million, respectively, at December 31, 2005 and 2004. Operational imbalance assets were approximately $16.3 million and $23.8 million, respectively, at December 31, 2005 and 2004 and operational imbalance liabilities were approximately $25.6 million and $13.9 million, respectively, at December 31, 2005 and 2004.

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

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

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, overheads and transportation costs 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, 2005 and 2004, respectively.

December 31 *(In millions)*	**2005**	2004
OGE Energy Corp. (holding company)		
Property, plant and equipment	**$ 76.3**	$ 65.2
OGE Energy Corp. property, plant and equipment	**76.3**	65.2
OG&E		
Distribution assets	**2,048.0**	1,934.0
Electric generation assets	**1,870.9**	1,828.3
Transmission assets	**597.0**	552.8
Intangible plant	**8.6**	6.3
Other property and equipment	**303.4**	313.0
OG&E property, plant and equipment	**4,827.9**	4,634.4
Enogex		
Transportation and storage assets	**683.6**	736.6
Gathering and processing assets	**566.5**	478.8

Marketing assets	**7.5**	7.5
Enogex property, plant and equipment	**1,257.6**	1,222.9
Total property, plant and equipment	**$ 6,161.8**	$ 5,922.5

Depreciation

OG&E

The provision for depreciation, which was approximately 3.0 percent and 2.9 percent, respectively, of the average depreciable utility plant for 2005 and 2004, is provided on a straight-line method over the estimated service life of the utility assets. Depreciation is provided at the unit level for production plant and at the account or sub-account level for all other plant, and is based on the average life group method. During early 2005, a depreciation study for OG&E was performed and new proposed depreciation rates were included as part of OG&E's May 20, 2005 rate case application with the OCC. In the OCC rate order issued in December 2005, the OCC approved the proposed depreciation rates which were implemented effective January 1, 2006. In 2006, the provision for depreciation is projected to be approximately 2.8 percent of the average depreciable utility plant. Amortization of intangibles other than debt costs is computed using the straight-line method. Approximately 75 percent of the intangible plant balance at December 31, 2005 will be amortized over three years with the remaining intangible plant being amortized over their respective lives ranging up to 25 years.

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 is not known at this time.

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

Revenue Recognition

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 recorded each month based on the current month's estimated volumes, 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, liabilities or against the brokerage deposits in Prepayments and Other in the Consolidated Balance Sheets.

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.

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 8 for a further discussion related to the Company's Stock Incentive Plan. The Company will adopt SFAS No. 123 (Revised), "Share-Based Payment," effective January 1, 2006, which will require the Company to measure and recognize the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award. The 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)*	**2005**	2004	2003
Net income, as reported	**$ 211.0**	$ 153.5	$ 129.8
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	**0.5**	1.0	1.2
Pro forma net income	**$ 210.5**	$ 152.5	$ 128.6
Income per average common share			
Basic – as reported	**$ 2.34**	$ 1.74	$ 1.59
Basic – pro forma	**$ 2.33**	$ 1.73	$ 1.57
Diluted – as reported	**$ 2.32**	$ 1.73	$ 1.58
Diluted – pro forma	**$ 2.32**	$ 1.72	$ 1.57

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, 2005 and 2004 are as follows:

December 31 *(In millions)*	**2005**	2004
Minimum pension liability adjustment, net of tax	**$ (91.1)**	$ (72.7)
Deferred hedging gains, net of tax	**3.1**	0.2
Settlement and amortization of cash flow hedge, net of tax	**(2.2)**	(2.5)
Total accumulated other comprehensive loss, net of tax	**$ (90.2)**	$ (75.0)

Minimum Pension Liability Adjustment

Accumulated other comprehensive loss included approximately a $91.1 million after tax loss ($148.6 million pre-tax) and approximately a $72.7 million after tax loss ($118.6 million pre-tax), respectively, at December 31, 2005 and 2004 related to a minimum pension liability adjustment based on a review of the funded status of the Company's pension plan by the Company's actuarial consultants as of December 31, 2005.

Cash Flow Hedges of Interest Rates

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

Environmental Costs

Accruals for environmental costs are recognized when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. Costs are charged to expense or deferred as a regulatory asset based on expected recovery from customers in future rates, if they relate to the remediation of conditions caused by past operations or if they are not expected to mitigate or prevent contamination from future operations. Where environmental expenditures relate to facilities currently in use, such as pollution control equipment, the costs may be capitalized and depreciated over the future service periods. Estimated remediation costs are recorded at undiscounted amounts, independent of any insurance or rate recovery, based on prior experience, assessments and current technology. Accrued obligations are regularly adjusted as environmental assessments and estimates are revised, and remediation efforts proceed. For sites where 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 2005 presentation.

2. Accounting Pronouncements

In October 2002, the Emerging Issues Task Force ("EITF") reached a consensus on certain issues covered in 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." One consensus of EITF 02-3 was to rescind EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," as amended, effective for fiscal periods beginning after December 15, 2002. Effective October 25, 2002, all new contracts and physical inventories that would have been accounted for under EITF 98-10 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 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 November 2004, the FASB issued SFAS No. 151, “Inventory Costs, an Amendment to ARB No. 43, Chapter 4.” This statement amends the guidance in Accounting Research Bulletin No. 43, Chapter 4 “Inventory Pricing”, to clarify the accounting for abnormal amounts of idle facility expense, freight, handling costs and spoilage. This statement requires these items to be recognized as current period charges regardless of whether the “so abnormal” criterion is met. Adoption of SFAS No. 151 is required for inventory costs incurred during fiscal years beginning after June 15, 2005. The Company will adopt this new standard effective January 1, 2006. Management does not expect the impact of this new standard to have a material effect on its consolidated financial position or results of operations.

In December 2004, the FASB issued SFAS No. 123 (Revised), which replaces SFAS No. 123 and supersedes APB Opinion No. 25. This statement applies to all share-based payment transactions in which an entity acquires goods or services by issuing (or offering to issue) its shares, share options or other equity instruments (except for equity instruments held by an employee share ownership plan) or by incurring liabilities to an employee or other supplier (a) in amounts based, at least in part, on the price of the entity’s shares or other equity instruments or (b) that require or may require settlement by issuing the entity’s equity shares or other equity instruments. This statement applies to all awards granted after the required effective date and to awards modified, repurchased or cancelled after that date. The cumulative effect of initially applying this statement, if any, is recognized as of the required effective date. This statement requires a public entity to measure and recognize the cost of employee services received in exchange for an award of equity instruments based on the grant-date fair value of the award (with limited exceptions). The grant-date fair value of employee share options and similar instruments will be estimated using option-pricing models adjusted for the unique characteristics of those instruments. If an equity award is modified after the grant date, incremental compensation cost will be recognized in an amount equal to the excess of the fair value of the modified award over the fair value of the original award immediately before the modification. As of the required effective date, all public entities that used the fair-value based method for either recognition or disclosure under SFAS No. 123 will apply this statement using a modified version of prospective application. Under that transition method, compensation cost is recognized on or after the required effective date for the portion of outstanding awards for which the requisite service has not yet been rendered, based on the grant-date fair value of those awards calculated under SFAS No. 123 for either recognition or pro forma disclosures. Adoption of SFAS No. 123(R) is required for public entities as of the beginning of the first annual period beginning after June 15, 2005. The Company will adopt this new standard effective January 1, 2006. Management does not expect the impact of this new standard to have a material effect on its consolidated financial position or results of operations.

In March 2005, the FASB issued FASB Interpretation No. 47, “Accounting for Conditional Asset Retirement Obligations,” in which an entity is required to recognize a liability for the fair value of an asset retirement obligation (“ARO”) that is conditional on a future event if the liability’s fair value can be reasonably estimated. The fair value of a liability for the conditional ARO should be recognized when incurred. Uncertainty surrounding the timing and method of settlement of a conditional ARO should be factored into the measurement of the liability when sufficient information exists. However, in some cases, there is insufficient information to estimate the fair value of an ARO. In these cases, the liability should be initially recognized in the period in which sufficient information is available for an entity to make a reasonable estimate of the liability’s fair value. FIN 47 required both recognition of a cumulative change in accounting principle and disclosure of the liability on a pro forma basis for transition purposes. FIN 47 is effective no later than the end of fiscal years ending after December 15, 2005. The Company adopted this new interpretation effective December 31, 2005 which resulted in an ARO of approximately $2.5 million being recorded for power plant structure legal obligations associated with various removal items, of which approximately $0.4 million is the ARO and approximately $2.1 million are cumulative accretion costs. Beginning January 1, 2006, the Company will amortize the remaining value of the related ARO assets over their remaining lives ranging from 20 to 50 years. The cumulative accretion costs of approximately $2.1 million that are included in the ARO were reclassified from the regulatory liability account associated with Accrued Removal Obligations to Asset Retirement Obligations on the Consolidated Balance Sheet and, as a result, there was no earnings impact from a cumulative effect adjustment due to a change in accounting principle. In addition, the cumulative depreciation expense for the ARO assets of approximately $0.2 that would have been recorded for the time period from the date the liability would have been originally recorded under FIN 47 was also reclassified from the regulatory liability account to accumulated depreciation for the ARO assets with no earnings impact. At December 31, 2003 and 2004, the pro forma amount of the ARO would have

been approximately $2.4 million. The Company has identified other ARO’s that have not been recorded because the Company determined that these assets have indefinite lives primarily related to OG&E’s power plant sites and Enogex’s processing plants.

In June 2005, the FASB issued SFAS No. 154, "Accounting Changes and Error Corrections," which replaces APB Opinion No. 20, "Accounting Changes" and SFAS No. 3, "Reporting Accounting Changes in Interim Financial Statements." SFAS No. 154 applies to all voluntary changes in accounting principle and requires retrospective application to prior periods' financial statements of changes in accounting principle unless it is impracticable to determine either the period-specific effects or the cumulative effect of the change. Adoption of SFAS No. 154 is required for accounting changes and error corrections made in fiscal years beginning after December 15, 2005. The Company will adopt this new standard effective January 1, 2006. Management does not expect the impact of this new standard to have a material effect on its consolidated financial position or results of operations.

In September 2005, the EITF reached a consensus and issued EITF Issue No. 04-13, "Accounting for Purchases and Sales of Inventory with the Same Counterparty" in which inventory purchase and sale transactions with the same counterparty that are entered into in contemplation of one another should be combined for purposes of applying APB Opinion No. 29, "Accounting for Nonmonetary Transactions." The EITF also concluded that exchanges of inventory should be recognized at carryover basis except for changes of finished goods for either raw materials or work in progress, which would be recognized at fair value. This consensus should be applied in the first interim or annual reporting period beginning after March 15, 2006 to new arrangements and previous arrangements that were modified or renegotiated after the effective date. Management does not expect the impact of this new standard to have a material effect 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 2005 and 2004, the Company's use of non-trading price risk management instruments involved the use of commodity price futures, commodity price swap contracts, interest rate swap agreements and treasury lock agreements. The commodity price futures, commodity price swap contracts and interest rate swap agreements involved the exchange of fixed price or rate payments in exchange for floating price or rate payments over the life of the instrument without an exchange of the underlying principal amount. The treasury lock agreements protected against the variability of future interest payments of long-term debt that was issued by OG&E in January 2006.

In accordance with SFAS No. 133, the Company recognizes its non-exchange traded 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. Exchange traded transactions that are subject to a master netting agreement are settled on a net basis daily through margin accounts with a clearing broker and, therefore, are recorded at fair value on a net basis in Prepayments and Other in the Consolidated Balance Sheets. The accounting for changes in the fair value of a derivative depends on the intended use of the derivative and resulting designation. For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative instrument is recognized in current earnings on the same line item as the gain or loss recorded for the change in the fair value of the hedged item. For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of Accumulated Other Comprehensive Income and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portion of a derivative's change in fair value is recognized currently in earnings. Forecasted transactions designated as the hedged item in a cash flow hedge are regularly evaluated to assess whether they continue to be probable of occurring. If the forecasted transactions are no longer probable of occurring, hedge accounting will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings. If the forecasted transactions are no longer reasonably possible of occurring, any associated amounts recorded in Accumulated Other Comprehensive Income will also be recognized directly in earnings.

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

natural gas liquids produced by its subsidiary, Enogex Products Corporation ("Products"), to electric power contracts by OG&E and for fuel procurement by OG&E.

At December 31, 2005, the Company had no outstanding interest rate swap agreements. At December 31, 2005, the Company's treasury lock agreements have been designated as cash flow hedges under SFAS No. 133. The Company measures ineffectiveness of the cash flow hedges under the hypothetical derivative method prescribed by SFAS No. 133. Under the hypothetical derivative method, the Company has designated that the critical terms of the hedging instrument are the same as the critical terms of the hypothetical derivative used to value the forecasted transaction, and, as a result, no ineffectiveness is expected. See Note 1 for a description of the Company's treasury lock agreements.

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 Issue No. 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

In April 2005, Enogex Compression received an unsolicited offer to buy its interest in Enerven, a joint venture focused on the rental of natural gas compression assets. After evaluating this offer, Enogex Compression sold its interest in Enerven for approximately $7.3 million in August 2005. Enogex Compression recognized an after tax gain of approximately $1.8 million related to the sale of this business.

Enogex regularly evaluates long term stability, profitability and core competency of each of its businesses within the regulatory and market framework in which each business operates. Based on these evaluations, in September 2005, Enogex announced that it had entered into an agreement to sell its interest in EAPC, which held the NOARK interest. This sale was completed on October 31, 2005. The Company received approximately $177.4 million cash proceeds and recognized an after tax gain of approximately $36.7 million from the sale of this business in the fourth quarter. Enogex used approximately $31.9 million of the proceeds to repay principal and accrued interest on long-term debt and approximately $46.7 million to pay taxes associated with EAPC. The balance of the proceeds of approximately $98.8 million will be used to invest, over time, in strategic assets to diversify its asset base.

The Consolidated Financial Statements of the Company have been restated to reflect Enogex Compression's sale of its Enerven interest and Enogex's sale of its EAPC interest, both of which were part of the Natural Gas Pipeline segment, as discontinued operations. Accordingly, revenues, costs and expenses and cash flows of Enerven and EAPC have been excluded from the respective captions in the Consolidated Financial Statements and have been separately reported as discontinued operations in the applicable financial statement captions. Summarized financial information for the discontinued operations as of December 31 is as follows:

CONSOLIDATED STATEMENTS OF INCOME DATA

(In millions)	**2005**	2004	2003
Operating revenues from discontinued operations	**$ 69.3**	$ 78.3	$ 79.8
Income from discontinued operations before taxes	**76.2**	9.4	9.8

CONSOLIDATED BALANCE SHEET DATA

(In millions)	**2005**	2004
Cash and cash equivalents	**$** ---	$ 3.3
Accounts receivable, net	---	3.4
Other	---	0.5
Total current assets of discontinued operations	**$** ---	$ 7.2
Plant in service of discontinued operations	**$** ---	$ 151.4
Less accumulated depreciation	---	18.8
Net property, plant and equipment of discontinued operations	**$** ---	$ 132.6
Total deferred charges and other assets of discontinued operations	**$** ---	$ 4.7
Accounts payable	**$** ---	$ 5.9
Accrued interest	---	0.4
Long-term debt due within one year	---	2.0
Other	---	1.3
Total current liabilities of discontinued operations	**$** ---	$ 9.6
Total long-term debt of discontinued operations	**$** ---	$ 65.0
Total deferred credits and other liabilities of discontinued operations	**$** ---	$ 18.3

5. Supplemental Cash Flow Information

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

Year ended December 31 *(In millions)*	**2005**	2004	2003
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Change in fair value of long-term debt due to interest rate swaps	**$ (7.8)**	$ 0.3	$ (8.3)
Power plant long-term service agreement	**---**	6.0	---
Issuance of common stock	**---**	2.2	11.4
Change in property, plant and equipment due to transfer of inventory	**---**	---	7.1
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash Paid During the Period for			
Interest (net of interest capitalized of $2.2, $1.7, $0.5)	**$ 95.9**	$ 85.2	$ 92.6
Income taxes (net of income tax refunds)	**42.0**	37.4	(33.2)

6. Income Taxes

The items comprising income tax expense are as follows:

Year ended December 31 *(In millions)*	**2005**	2004	2003
Provision (Benefit) for Current Income Taxes from Continuing Operations			
Federal	**$ 45.3**	$ 21.8	$ (36.6)
State	**5.3**	2.5	(6.3)
Total Provision (Benefit) for Current Income Taxes from Continuing Operations	**50.6**	24.3	(42.9)
Provision for Deferred Income Taxes, net from Continuing Operations			
Federal	**27.0**	51.2	103.7
State	**---**	4.4	15.8
Total Provision for Deferred Income Taxes, net from Continuing Operations	**27.0**	55.6	119.5
Deferred Federal Investment Tax Credits, net	**(5.1)**	(5.2)	(5.2)
Income Taxes Relating to Other Income and Deductions	**(0.7)**	2.4	(0.6)
Total Income Tax Expense from Continuing Operations	**$ 71.8**	$ 77.1	$ 70.8

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. During 2005, new guidelines were issued by the Internal Revenue Service ("IRS") related to the change in the method of accounting used to capitalize costs for self-construction discussed above. As part of the Company's current IRS examination process, this change in method of accounting has been identified as an issue under examination. The Company believes its change in accounting method was in accordance with IRS regulations in effect at the time and will continue to vigorously defend its position. While the outcome of this process is uncertain at this time, during 2005 OG&E recorded approximately $3.3 million for additional interest expense related to income taxes as a result of a potential adjustment. This amount is included in Interest on Short-Term Debt and Other Interest Charges in the Consolidated Statements of Income. OG&E expects to continue to accrue approximately $0.3 million monthly in 2006 for additional interest expense related to this matter.

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

Year ended December 31	**2005**	2004	2003
Statutory federal tax rate	**35.0%**	35.0%	35.0%
State income taxes, net of federal income tax benefit	**1.7**	2.0	3.1
Excess deferred taxes (A)	**(2.2)**	---	---
Tax credits, net	**(2.1)**	(2.3)	(2.6)
ESOP dividends	**(1.7)**	---	---
Medicare Part D subsidy	**(1.3)**	---	---
Other, net	**0.8**	(0.4)	(0.3)
Effective income tax rate as reported	**30.2%**	34.3%	35.2%

(A) During 2005, the Company performed a detailed analysis of all deferred tax assets and liabilities. In connection with this analysis, it was determined that an excess liability existed. The removal of this excess liability caused a permanent difference in the effective tax rate for 2005 of approximately 2.2 percent.

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, 2005 and 2004, respectively, are as follows:

(In millions)	**2005**	2004
Current Accumulated Deferred Tax Assets		
Accrued vacation	**$ 6.3**	$ 6.0
Provision for rate refund	**2.7**	0.4
Capitalized indirect construction costs	**1.7**	0.8
Uncollectible accounts	**1.4**	1.8
Other	**2.2**	4.7
Total Current Accumulated Deferred Tax Assets	**$ 14.3**	$ 13.7
Non-Current Accumulated Deferred Tax Liabilities		
Accelerated depreciation and other property related differences	**$ 826.4**	$ 781.6
Income taxes refundable to customers, net	**12.7**	11.9
Bond redemption-unamortized costs	**6.9**	7.3
Company pension plan	**---**	2.6
Other	**0.7**	1.3
Total Non-Current Accumulated Deferred Tax Liabilities	**846.7**	804.7
Non-Current Accumulated Deferred Tax Assets		
Postretirement medical and life insurance benefits	**(15.3)**	(10.2)
Company pension plan	**(13.6)**	---
Deferred federal investment tax credits	**(8.6)**	(10.3)
Other	**(2.1)**	---
Total Non-Current Accumulated Deferred Tax Assets	**(39.6)**	(20.5)
Non-Current Accumulated Deferred Income Tax Liabilities, net	**$ 807.1**	$ 784.2

OG&E has an Oklahoma investment tax credit carryover of approximately $6.8 million. These Oklahoma credit carryover amounts will begin expiring in the year 2017. During 2005, additional Oklahoma tax credits of approximately $4.1 million were generated by OG&E and Enogex. The Company believes that, based on current projections, the entire $10.9 million of these state tax credit amounts will be fully utilized in 2006.

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

American Jobs Creation Act of 2004

On October 22, 2004, President Bush signed into law the American Jobs Creation Act of 2004 (the “Jobs Creation Act”). The Jobs Creation Act amended and added a significant number of provisions to the Internal Revenue Code (the “Code”) and these changes affect virtually all taxpayers. The Jobs Creation Act includes a provision that entitles all U.S. manufacturers with qualified manufacturing activities to a “Deduction Related to Production Activities” (“DRPA”). Certain activities of the Company, including the generation of electricity 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 October 20, 2005 and this guidance provides rules for determining taxable income when a portion of a taxpayer's income is derived from a qualified production activity. The FASB has determined that the DRPA will be classified as a "special deduction" for purposes of computing income tax expense which will have the effect of reducing the Company's overall effective tax rate to the extent the Company can claim

a deduction. For 2005, the Company's income tax benefit was approximately $0.5 million for OG&E and was approximately $0.5 million for Products.

7. 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 July 2005, 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, 2005, the Company purchased common stock on the open market to satisfy the common stock requirements of the DRIP/DSPP and therefore did not issue any new shares of common stock. 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 and 938,497 shares of common stock at no discount during the years ended December 31, 2004 and 2003, respectively.

For the years ended December 31, 2005, 2004 and 2003, respectively, there were 606,802, 392,686 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, 2005, there were 15,338,204 shares of unissued common stock reserved for the various employee and Company stock plans.

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.

The Company's Restated Certificate of Incorporation permits the issuance of a new series of preferred stock with dividends payable other than quarterly.

8. Stock Incentive Plan

On January 21, 1998, the Company adopted a Stock Incentive Plan (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.

Performance Units

During 2005, 2004, and 2003, respectively, the Company awarded 201,794, 162,591 and 128,469 performance units to certain employees of the Company. These performance units represent the value of one share stock. The 2003, 2004 and 2005 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. Also, for the 2005 performance units, the performance units are contingently awarded based on the Company's earnings per share growth over a three-year award cycle. Each performance unit is subject to forfeiture if the recipient ceases to render substantial services to the Company or a subsidiary for any reason other than death, disability or retirement. During 2005, 2004 and 2003, the Company recorded approximately $0.9 million, $3.6 million and $1.5 million, respectively, related to expense for the performance units which are accounted for under the liability method.

Stock Options

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

	2005		2004		2003	
	Number of Options	**Weighted Average Price**	Number of Options	Weighted Average Price	Number of Options	Weighted Average Price
Options Outstanding at beginning of year	**2,827,914**	**$22.16**	2,871,802	$21.63	2,419,360	$23.44
Granted	---	---	380,400	23.58	838,700	16.69
Exercised	**(606,802)**	**21.75**	(392,686)	19.56	(134,098)	18.82
Cancelled	**(81,736)**	**24.15**	(31,602)	23.25	(252,160)	24.10
Options Outstanding at end of year	**2,139,376**	**$22.20**	2,827,914	$22.16	2,871,802	$21.63
Options Exercisable at end of year	**1,734,978**	**$22.70**	1,809,441	$23.29	1,408,255	$24.20

The fair value of each option grant under the Plans for the years ended December 31, 2004 and 2003 are estimated on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions used for grants in 2004 and 2003. There were no stock option grants during 2005.

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

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

		Options Outstanding		Options Exercisable	
Range of Exercise Prices	Weighted-Average Remaining Contractual Life	Number Outstanding	Weighted-Average Exercise Price	Number Outstanding	Weighted-Average Exercise Price
$16.69 - $22.70	6.03 years	1,299,173	$ 19.82	1,091,256	$ 20.41
$23.58 - $28.75	4.42 years	840,203	$ 25.88	643,722	$ 26.58

9. 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)*	**2005**	2004	2003
Average Common Shares Outstanding			
Basic average common shares outstanding	90.3	88.0	81.8
Effect of dilutive securities:			
Employee stock options and unvested stock grants	0.2	0.3	0.1
Contingently issuable shares (performance units)	0.3	0.2	0.2
Diluted average common shares outstanding	90.8	88.5	82.1

For the years ended December 31, 2005, 2004 and 2003, respectively, approximately 0.2 million shares, 0.6 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.

10. Long-Term Debt

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

Refinancing of Long-Term Debt

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

Long-Term Debt with Optional Redemption Provisions

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

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

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

Interest Rate Swap Agreements

Fair Value Hedges

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

On April 1, 2005, Enogex terminated two interest rate swap agreements (with a total notional amount of $200 million) and received approximately $0.2 million related to this transaction. Since inception of the Enogex interest rate swap

agreements, which converted $200 million of 8.125 percent fixed rate debt due January 15, 2010 to a floating rate based upon the three and six month LIBOR, the Company has paid approximately $81.3 million in interest and has received approximately $29.9 million related to these agreements. The effective interest rate until maturity will be approximately 7.67 percent on this long-term debt.

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

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

Long-term Debt Maturities

Maturities of the Company's long-term debt during the next five years consist of $3.0 million in 2007; $1.0 million in 2008 and $400.0 million in 2010. There are no maturities of the Company's long-term debt in years 2006 or 2009.

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 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.

11. 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 short-term debt balance was approximately $250.0 million and $125.0 million at December 31, 2005 and 2004, respectively, at a weighted-average interest rate of 4.421 percent and 2.467 percent, respectively. In accordance with SFAS No. 6, "Classification of Short-Term Obligations Expected to Be Refinanced, an Amendment of ARB No. 43, Chapter 3A," $220 million in commercial paper and bank borrowings was used to temporarily fund the matured and called long-term debt for OG&E. This commercial paper was classified as long-term debt in the Consolidated Statement of Capitalization at December 31, 2005 as OG&E planned to refinance this amount. Subsequently, OG&E issued long-term debt in January 2006. The following table shows the Company's lines of credit in place, commercial paper outstanding and available cash at December 31, 2005. At December 31, 2005, the Company's short-term borrowings consisted of commercial paper.

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

Entity	Amount Available	Amount Outstanding	Weighted-Average Interest Rate	Maturity
Energy Corp. (B)	$ 600.0	$ 150.0	4.435%	September 30, 2010 (A)
The Company (C)	150.0	100.0	4.400%	September 30, 2010 (A)
Energy Corp.	15.0	---	N/A	April 6, 2006
	765.0	250.0	4.421%	
Cash	26.4	N/A	N/A	N/A
Total	$ 765.0	$ 250.0	4.421%	

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

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

Unlike 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 for a two-year period beginning January 1, 2005 and ending December 31, 2006.

12. 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. For employees hired on or after February 1, 2000, the pension plan is 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 a benefit based primarily on years of service and the average of the five highest consecutive years of compensation during an employee's last 10 years prior to retirement, with reductions in benefits for each year prior to age 62 unless the employee's age and years of credited service equal or exceed 80.

It is 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 2005 and 2004, the Company made contributions to its pension plan of approximately $32.0 million and $69.0 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 2006, the Company may contribute up to $90 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 funding requirements specified by the Employee Retirement Income Security Act of 1974, as amended.

During 2005 and 2004, 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, 2005 and 2004 of approximately $88.9 million and $92.0 million, respectively. At December 31, 2005 and 2004, 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 $154.6 million and $123.3 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 required the recognition of an additional minimum liability in the amount of approximately $181.4 million and $156.6 million, respectively, at December 31, 2005 and 2004. The offset of this entry was an intangible asset and Accumulated Other Comprehensive Income, net of a deferred tax asset; therefore, this adjustment did not impact the results of operations in 2005 or 2004 and did not require a usage of cash and is therefore excluded from the 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, 2005 and 2004:

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

Investment Policies and Strategies

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

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

Asset Class	**Target Allocation**	**Minimum**	**Maximum**
Domestic Equity	30 %	--- %	60 %

Domestic Mid-Cap Equity	10 %	--- %	10 %
Domestic Small-Cap Equity	10 %	--- %	10 %
International Equity	10 %	--- %	10 %
Fixed Income Domestic	38 %	30 %	70 %
Cash	2 %	--- %	5 %

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

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

Asset Class	**Comparative Benchmark(s)**
Fixed Income	Lehman Aggregate Index
Equity Index	S&P 500 Index
Value Equity	Russell 1000 Value Index – Short-term
	S&P 500 Index – Long-term
Growth Equity	Russell 1000 Growth Index – Short-term
	S&P 500 Index – Long-term
Mid-Cap Equity	S&P 400 Midcap Index
Small-Cap Equity	Russell 2000 Index
International Equity	Morgan Stanley Capital International Europe, Australia and Far East Index

The fixed income manager is expected to use discretion over the asset mix of the trust assets in its efforts to maximize risk-adjusted performance. Exposure to any single issuer, other than the U.S. government, its agencies, or its (which have no limits) is limited to five percent of the fixed income portfolio as measured by market value. At least 75 percent of the invested assets must possess an investment grade rating at or above Baa3 or BBB- by Moody's Investors Service ("Moody's"), Standard & Poor's Ratings Services ("Standard & Poor's") or Fitch Ratings ("Fitch"). The

portfolio may invest up to 10 percent of the portfolio's market value in convertible bonds as long as the securities purchased meet the quality guidelines. The purchase of any of the Company's equity, debt or other securities is prohibited.

The domestic value equity managers focus on stocks that the manager believes are undervalued in price and earn an average or less than average return on assets, and often pays out higher than average dividend payments. The domestic growth equity manager will invest primarily in growth companies which consistently experience above average growth in earnings and sales, earn a high return on assets, and reinvest cash flow into existing business. The domestic mid-cap equity portfolio manager focuses on companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the S&P 400 Midcap Index, small dividend yield, return on equity at or near the S&P 400 Midcap Index and earnings per share growth rate at or near the S&P 400 Midcap Index. The domestic small-capitalization equity manager will purchase shares of companies with market capitalizations lower that the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell 2000, small dividend yield, return on equity at or near the Russell 2000 and earnings per share growth rate at or near the Russell 2000. The international global equity manager invests primarily in non-dollar denominated equity securities. Investing internationally diversifies the overall trust across the global equity markets. The manager is required to operate under certain restrictions including: regional constraints, diversification requirements and percentage of U.S. securities. The Morgan Stanley Capital International Europe, Australia and the Far East Index ("EAFE") is the benchmark for comparative performance purposes. The EAFE Index is a market value weighted index comprised of over 1,000 companies traded on the stock markets of Europe, Australia, New Zealand and the Far East. All of the equities which are purchased for the international portfolio are thoroughly researched. Only companies with a market capitalization in excess of $100 million are allowable. No more than five percent of the portfolio can be invested in any one stock at the time of purchase. All securities are freely traded on a recognized stock exchange and there are no 144-A securities and no over-the-counter derivatives. The following investment categories are excluded: options (other than traded currency options), commodities, futures (other than currency futures or currency hedging), short sales/margin purchases, private placements, unlisted securities and real estate (but not real estate shares).

For all domestic equity investment managers, no more than eight percent (five percent for mid-cap and small-cap equity managers) can be invested in any one stock at the time of purchase and no more than 16 percent (10 percent for mid-cap and small-cap equity managers) after accounting for price appreciation. A minimum of 95 percent of the total assets of an equity manager's portfolio must be allocated to the equity markets. Options or financial futures may not be purchased unless prior approval of the Committee is received. The purchase of securities on margin is prohibited as is securities lending. Private placement or venture capital may not be purchased. All interest and dividend payments must be swept on a daily basis into a short-term money market fund for re-deployment. The purchase of any of the Company's equity, debt or other securities is prohibited. The purchase of equity or debt issues of the portfolio manager's organization is also prohibited. The aggregate positions in any company may not exceed one percent of the fair market value of its outstanding stock.

Restoration of Retirement Income Plan

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

Postretirement Benefit Plans

In addition to providing pension benefits, 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 credited service total or exceed 80 or have attained age 55 with 10 years of vesting service at the time of retirement are entitled to these postretirement benefits. Employees hired on or after February 1, 2000, are not entitled to 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)	**2005**	2004	**2005**	2004
Beginning obligations	**$ (548.2)**	$ (485.4)	**$ (192.3)**	$ (181.1)
Service cost	**(19.1)**	(16.9)	**(3.2)**	(3.0)
Interest cost	**(30.3)**	(29.7)	**(10.5)**	(11.1)
Participants' contributions	---	---	**(3.9)**	(3.0)
Plan changes / other	---	(7.2)	---	---
Actuarial losses	**(38.9)**	(56.0)	**(12.0)**	(7.0)
Benefits paid	**42.5**	47.0	**13.7**	12.9
Ending obligations	**$ (594.0)**	$ (548.2)	**$ (208.2)**	$ (192.3)

Fair Value of Plans' Assets

	Pension Plan and Restoration of Retirement Income Plan		Postretirement Benefit Plans	
(In millions)	**2005**	2004	**2005**	2004
Beginning fair value	**$ 424.9**	$ 353.6	**$ 64.0**	$ 56.0
Actual return on plans' assets	**23.9**	46.6	**4.6**	9.3
Employer contributions	**33.1**	71.7	**8.4**	8.6
Participants' contributions	---	---	**3.9**	3.0
Benefits paid	**(42.5)**	(47.0)	**(13.7)**	(12.9)
Ending fair value	**$ 439.4**	$ 424.9	**$ 67.2**	$ 64.0

Net Periodic Benefit Cost

	Pension Plan and Restoration of Retirement Income Plan	Postretirement Benefit Plans

(In millions)	**2005**	2004	2003	**2005**	2004	2003
Service cost	**$ 19.1**	$ 16.9	$ 15.2	**$ 3.2**	$ 3.0	$ 3.0
Interest cost	**30.3**	29.7	29.2	**10.5**	11.1	10.9
Return on plan assets	**(34.2)**	(31.6)	(24.3)	**(5.5)**	(5.5)	(5.5)
Amortization of transition obligation	**---**	---	---	**2.7**	2.7	2.7
Amortization of net loss	**14.7**	11.9	13.2	**5.0**	4.9	3.4
Amortization of unrecognized prior service cost	**6.3**	6.3	5.8	**2.1**	2.1	2.1
Net periodic benefit cost	**$ 36.2**	$ 33.2	$ 39.1	**$ 18.0**	$ 18.3	$ 16.6

The capitalized portion of the net periodic pension benefit cost was approximately $9.3 million, $8.4 million and $5.8 million at December 31, 2005, 2004 and 2003, respectively. The capitalized portion of the net periodic postretirement benefit cost was approximately $4.7 million, $5.0 million and $2.6 million at December 31, 2005, 2004 and 2003, respectively.

Funded Status of Plans

	Pension Plan and Restoration of Retirement Income Plan		Postretirement Benefit Plans	
(In millions)	**2005**	2004	**2005**	2004
Funded status of the plans	**$ (154.6)**	$ (123.3)	**$ (141.0)**	$ (128.3)
Unrecognized net loss	**210.1**	175.6	**71.3**	63.4
Unrecognized prior service cost	**33.4**	39.7	**7.1**	9.2
Unrecognized transition obligation	**---**	---	**19.2**	22.0
Net amount recognized	**$ 88.9**	$ 92.0	**$ (43.4)**	$ (33.7)

Amounts recognized in the Consolidated Balance Sheets consist of:

	Pension Plan and Restoration of Retirement Income Plan	
(In millions)	**2005**	2004
Prepaid benefit obligation	**$ 90.2**	$ 92.7
Accrued pension and benefit obligations	**(182.8)**	(157.3)
Intangible asset - unamortized prior service cost	**32.8**	38.0
Accumulated deferred tax asset	**57.5**	45.9
Accumulated other comprehensive loss, net of tax	**91.2**	72.7
Net amount recognized	**$ 88.9**	$ 92.0

Rate Assumptions

	Pension Plan			Postretirement Benefit Plans		
	2005	2004	2003	**2005**	2004	2003
Discount rate	**5.50%**	5.75%	6.25%	**5.50%**	5.75%	6.25%
Rate of return on plans' assets	**8.50%**	8.75%	8.75%	**8.50%**	8.75%	8.75%
Compensation increases	**4.50%**	4.50%	4.50%	**4.50%**	4.50%	4.50%
Assumed health care cost trend:						
Initial trend	**N/A**	N/A	N/A	**9.00%**	10.00%	11.00%
Ultimate trend rate	**N/A**	N/A	N/A	**4.50%**	4.50%	4.50%
Ultimate trend year	**N/A**	N/A	N/A	**2011**	2010	2010

N/A - not applicable

The overall expected rate of return on plan assets assumption was decreased from 8.75 percent in 2004 to 8.50 percent in 2005 in determining net periodic pension cost. The rate of return on plan assets assumption is the average long-term rate of earnings expected on the funds currently invested and to be invested for the purpose of providing benefits specified by the pension plan or postretirement benefit plans. This assumption is reexamined at least annually and updated as necessary. The rate of return on plan assets assumption reflects a combination of historical return analysis, forward-looking return expectations and the plans' current and expected asset allocation.

The Company expects to pay benefits related to its pension plan and restoration of retirement income plan of approximately $64.6 million in 2006, $61.6 million in 2007, $64.0 million in 2008, $64.6 million in 2009, $61.8 million in 2010 and an aggregate of $299.1 million in years 2011 to 2015. These expected benefits were based on the same assumptions used to measure the Company's benefit obligation at the end of the year and include benefits attributable to estimated future employee service.

The assumed health care cost trend rates have a significant effect on the amounts reported for postretirement medical benefit plans. Future health care cost trend rates are assumed to be nine percent in 2006 with the rates decreasing in subsequent years by one percentage point per year through 2010. A one-percentage point change in the assumed health care cost trend rate would have the following effects:

ONE-PERCENTAGE POINT INCREASE

(In millions)	**2005**	2004	2003
Effect on aggregate of the service and interest cost components	**$ 1.8**	$ 1.9	$ 1.9
Effect on accumulated postretirement benefit obligations	**26.9**	24.2	23.1

ONE-PERCENTAGE POINT DECREASE

(In millions)	**2005**	2004	2003
Effect on aggregate of the service and interest cost components	**$ 1.5**	$ 1.5	$ 1.5
Effect on accumulated postretirement benefit obligations	**22.0**	19.8	18.9

Medicare Prescription Drug, Improvement and Modernization Act of 2003

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the “Medicare Act”). The Medicare Act expanded Medicare to include, for the first time, coverage for prescription drugs. In May 2004, the FASB issued FASB Staff Position No. FAS 106-2, “Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003.” FAS 106-2 provides guidance on the accounting for the effects of the Medicare Act for employers that sponsor postretirement heath care plans that provide prescription drug benefits. FAS 106-2 also requires those employers to provide certain disclosures regarding the effect of the federal subsidy provided by the Medicare Act. 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 $29.8 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 $5.2 million annually. The $5.2 million in annual savings is comprised of a reduction of approximately $3.1 million from amortization of the $29.8 million gain due to the reduction of the APBO, a reduction in the interest cost on the APBO of approximately $1.7 million and a reduction in the service cost due to the subsidy of approximately $0.4 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 2006, $11.4 million in 2007, $12.3 million in 2008, $13.1 million in 2009, $13.9 million in 2010 and an aggregate of $79.8 million in years 2011 to 2015. The Company expects to receive federal subsidy receipts provided by the Medicare Act of approximately $1.0 million in 2006, $1.1 million in 2007, $1.3 million in 2008, $1.4 million in 2009, $1.5 million in 2010 and an aggregate of $9.1 million in years 2011 to 2015. The Company did not receive any federal subsidy receipts in 2005; however, the Company’s 2005 SFAS No. 106 expense reflects credit for the expected future subsidies, thus reducing the expense.

Defined Contribution Plan

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 $6.7 million, $6.2 million and $5.6 million during 2005, 2004 and 2003, 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 related to the Company's executive officers in this plan as Accrued Pension and Benefit Obligations and the Company accounts for the contributions related to the Company's directors in this plan as Other Deferred Credits and Other Liabilities in the Consolidated Balance Sheets. 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.

13. 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. Other Operations for the year ended December 31, 2005 primarily includes unallocated corporate expenses, interest expense on commercial paper and interest expense on long-term debt. Other Operations for the year ended December 31, 2004 and 2003 primarily includes unallocated corporate expenses, interest expense to unconsolidated affiliate and interest expense on commercial paper. 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, 2005, 2004 and 2003.

2005	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	**$ 1,720.7**	**$4,369.1**	**$ ---**	**$ (141.6)**	**$5,948.2**
Cost of goods sold	**994.2**	**4,111.2**	**---**	**(142.3)**	**4,963.1**
Gross margin on revenues	**726.5**	**257.9**	**---**	**0.7**	**985.1**
Other operation and maintenance	**309.2**	**100.5**	**(10.9)**	**---**	**398.8**
Depreciation	**134.4**	**43.9**	**7.8**	**---**	**186.1**
Taxes other than income	**50.7**	**15.8**	**3.2**	**---**	**69.7**
Operating income (loss)	**232.2**	**97.7**	**(0.1)**	**0.7**	**330.5**

Other income (loss)	**(2.3)**	**0.8**	**1.7**	**---**	**0.2**
Other expense	**(3.0)**	**(0.3)**	**(2.7)**	**---**	**(6.0)**
Interest income	**2.6**	**2.9**	**1.7**	**(3.7)**	**3.5**
Interest expense	**(47.2)**	**(32.6)**	**(14.2)**	**3.7**	**(90.3)**
Income tax expense (benefit)	**52.6**	**23.6**	**(4.7)**	**0.3**	**71.8**
Income (loss) from continuing operations	**129.7**	**44.9**	**(8.9)**	**0.4**	**166.1**
Income from discontinued operations	**---**	**44.9**	**---**	**---**	**44.9**
Net income (loss)	**$ 129.7**	**$ 89.8**	**$ (8.9)**	**$ 0.4**	**$ 211.0**
Total assets	**$ 3,255.0**	**$1,680.1**	**$ 1,962.0**	**$ (1,998.2)**	**$4,898.9**
Capital expenditures	**$ 249.1**	**$ 36.2**	**$ 13.4**	**$ ---**	**$ 298.7**

(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.

2005	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	**$ 246.4**	**$ 681.2**	**$ 3,995.3**	**$ (553.8)**	**$4,369.1**
Operating income (loss)	**$ 37.1**	**$ 66.8**	**$ (6.2)**	**$ ---**	**$ 97.7**
Income (loss) from continuing operations	**$ 43.5**	**$ 43.4**	**$ (6.0)**	**$ (36.0)**	**$ 44.9**

(B) In March 2005, Enogex corrected its procedure for accounting for park and loan transactions (natural gas storage transactions) during 2004 that resulted from an incorrect change in an accounting procedure implemented during 2004. The incorrect procedure affected the timing of recognition of revenue and income from park and loan transactions and resulted in a temporary overstatement of operating revenues without the associated expense until the transaction was completed and the expense recognized. As a result of this correction, Enogex recorded a pre-tax charge of approximately $7.7 million ($4.7 million after tax or $0.05 per share) as a reduction in Operating Revenues in the Condensed Consolidated Statement of Income and a corresponding $7.7 million decrease in Current Price Risk Management Assets in the Condensed Consolidated Balance Sheet during the three months ended March 31, 2005.

2004	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	$ 1,578.1	$3,421.7	$ ---	$ (95.4)	$4,904.4
Cost of goods sold	914.2	3,143.6	---	(94.7)	3,963.1
Gross margin on revenues	663.9	278.1	---	(0.7)	941.3
Other operation and maintenance	301.9	97.3	(11.2)	---	388.0
Depreciation	122.7	44.0	8.3	---	175.0
Impairment of assets	---	7.8	---	---	7.8
Taxes other than income	47.0	16.4	3.3	---	66.7
Operating income (loss)	192.3	112.6	(0.4)	(0.7)	303.8
Other income	5.8	4.5	1.5	---	11.8
Other expense	(2.7)	(0.3)	(2.1)	---	(5.1)
Interest income	2.7	3.2	1.3	(2.3)	4.9
Interest expense	(37.5)	(32.2)	(23.4)	2.3	(90.8)
Income tax expense (benefit)	53.0	33.1	(8.7)	(0.3)	77.1
Income (loss) from continuing operations	107.6	54.7	(14.4)	(0.4)	147.5
Income from discontinued operations	---	6.0	---	---	6.0
Net income (loss)	$ 107.6	$ 60.7	$ (14.4)	$ (0.4)	$ 153.5
Total assets	$ 3,057.7	$1,740.3	$ 1,717.1	$ (1,712.2)	$4,802.9
Capital expenditures	$ 391.2	$ 31.2	$ 8.5	$ ---	$ 430.9

(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	$ 249.4	$ 566.5	$ 3,056.1	$ (450.3)	$3,421.7
Operating income	$ 46.9	$ 56.2	$ 9.5	$ ---	$ 112.6
Income from continuing operations	$ 52.9	$ 37.8	$ 5.9	$ (41.9)	$ 54.7

2003	Electric Utility	Natural Gas Pipeline (A)	Other Operations	Intersegment	Total
(In millions)					
Operating revenues	$1,517.1	$ 2,306.2	$ ---	$ (65.9)	$ 3,757.4
Cost of goods sold	837.3	2,070.2	---	(65.9)	2,841.6
Gross margin on revenues	679.8	236.0	---	---	915.8
Other operation and maintenance	294.8	87.4	(14.3)	---	367.9
Depreciation	121.8	40.9	10.9	---	173.6
Impairment of assets	---	9.2	1.0	---	10.2
Taxes other than income	46.9	16.4	2.9	---	66.2
Operating income (loss)	216.3	82.1	(0.5)	---	297.9
Other income	0.6	0.7	0.7	---	2.0
Other expense	(3.2)	(1.6)	(2.8)	---	(7.6)
Interest income	0.7	0.8	1.7	(1.9)	1.3
Interest expense	(38.8)	(34.1)	(21.3)	1.9	(92.3)
Income tax expense (benefit)	60.2	19.8	(9.2)	---	70.8
Income (loss) from continuing operations	115.4	28.1	(13.0)	---	130.5
Income from discontinued operations	---	4.7	---	---	4.7
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	$2,737.5	$ 1,561.2	$ 1,716.4	$ (1,454.7)	$ 4,560.4
Capital expenditures	$ 148.7	$ 27.5	$ 4.6	$ ---	$ 180.8

(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.

2003	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	$ 177.6	$ 511.7	$ 1,963.7	$ (346.8)	$ 2,306.2

Operating income	$	55.1	$	14.0	$	13.0	$	---	$	82.1
Income from continuing operations	$	20.4	$	8.4	$	7.9	$	(8.6)	$	28.1

14. Commitments and Contingencies

Capital Expenditures

The Company's capital expenditures are estimated at approximately: 2006 – $307.0 million, 2007 – $248.0 million and 2008 - $250.0 million.

Operating Lease Obligations

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

(In millions)	2006	2007	2008	2009	2010	2011 and Beyond
Operating lease obligations						
OG&E railcars	$ 4.3	$ 4.0	$ 3.9	$ 3.8	$ 3.7	$ 36.6
Enogex noncancellable operating leases	3.3	0.9	0.1	0.1	0.1	0.1
Total operating lease obligations	$ 7.6	$ 4.9	$ 4.0	$ 3.9	$ 3.8	$ 36.7

Payments for operating lease obligations were approximately $9.7 million, $9.7 million and $9.8 million in 2005, 2004 and 2003, respectively.

OG&E Railcar Lease Agreement

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

During 2005, 2004 and 2003, OG&E made total payments to cogenerators of approximately $183.8 million, $203.5 million and $203.0 million, respectively, of which approximately $95.5 million, $155.3 million and $164.7 million, respectively, represented capacity payments. All payments for purchased power, including cogeneration, are included in the Consolidated Statements of Income as Cost of Goods Sold. The future minimum capacity payments under the contracts are approximately: 2006 – $98.6 million, 2007 – $97.1 million, 2008 – $95.4 million, 2009 – $93.6 million and 2010 – $91.7 million. The minimum capacity payment amounts for 2008 through 2010 assume OG&E elects to extend certain cogeneration contracts, which otherwise expire at the end of 2007.

Fuel Minimum Purchase Commitments

OG&E purchased necessary fuel supplies of coal and natural gas for its generating units of approximately $163.5 million, $166.5 million and $157.3 million for the years ended December 31, 2005, 2004 and 2003, respectively. OG&E has

entered into purchase commitments of necessary fuel supplies of approximately: 2006 – $184.4 million, 2007 – $169.4 million, 2008 – $189.6 million, 2009 – $99.0 million, 2010 – $103.3 million and 2011 and Beyond – $86.8 million.

Natural Gas Units

OG&E utilized a request for bid ("RFB") to acquire approximately 30 percent of its projected annual natural gas requirements for 2006. All of these contracts are tied to various gas price market indices and most will expire in December 2006. Additional natural gas supply for the summer of 2006 will be secured through a new RFB issued in the first quarter of 2006. 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"). In 1999 a dispute arose as to whether the natural gas deliverability for the Stuart Storage Facility was being provided to Enogex by COOG and these issues were submitted to arbitration in the fourth quarter of 2001 resulting in an arbitration award against COOG and in favor of Enogex in the amount of approximately $23.3 million (the "COOG Judgment").

In 2002, Enogex exercised the asset purchase option provided in the Agreement and title to the Stuart Storage Facility was transferred to Enogex. In addition, under a related transaction, Natural Gas Storage Corporation ("NGSC"), an affiliate of COOG, went into default relating to a $12 million secured loan ("NGSC Loan") with the Company.

In 2002, a legal proceeding was filed by COOG and NGSC against the Company and Enogex in Texas – Natural Gas Storage Corporation and Central Oklahoma Oil and Gas Corp. v. OGE Energy Corp. and Enogex, Case No. 2002-38894; District Court of Harris County, Texas. COOG and NGSC stated a claim for declaratory judgment and breach of contract, asserting that NGSC was not obligated to make payments on the NGSC Loan. The Company objected to being sued in Texas based on lack of jurisdiction over the Company. Enogex responded to the allegations, asserting that the disputed issues have already been properly determined by the Arbitration Panel and, therefore, such action was improper. In 2003, the Texas Court granted Enogex's request for arbitration. In 2004, COOG, NGSC, Enogex and the Company submitted remaining issues to a second arbitration panel. The arbitration panel rendered a decision in the Company's favor for approximately $5.0 million related to the outstanding NGSC Loan (the "NGSC Judgment"). After the arbitration award, the plaintiffs, in the pending Texas action, amended the petition and moved to dismiss Enogex from the suit. The court granted the dismissal by order dated January 26, 2005. On September 30, 2005, an order was entered by the Texas Court disposing of the remaining and entire Texas action based on a lack of jurisdiction.

In 2003, the Company and Enogex brought separate complaints in the Western District of Oklahoma Federal Court 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. The Company and Enogex each stated claims for fraudulent transfer and breach of fiduciary duty. A jury trial was held in 2004 and the jury ruled in favor of the Company and Enogex for approximately $6.6 million ("Thrash Fraudulent Transfer Judgment"). In April 2005, the defendants filed an appeal in the Tenth Circuit Court of Appeals and on September 14, 2005, the defendants posted a cash bond for approximately $6.9 million to stay the execution of the Thrash Fraudulent Transfer Judgment pending appeal. On December 30, 2005, the parties reached a settlement of the Thrash Fraudulent Transfer Judgment, the COOG Judgment, the NGSC Judgment and related matters. The individual defendants agreed to pay approximately $5.2 million (the "Settlement Agreement") from the cash bond paid into the appeal court. In addition, the parties agreed to dismiss the pending appeal of the Thrash Fraudulent Transfer Judgment to the Tenth Circuit. The Settlement Agreement has been accounted for as a gain contingency and will be recognized in the Company's financial statements when the Settlement Agreement has been received which is expected in the first quarter of 2006. Upon payment of the Settlement Agreement, the Company will consider these matters closed.

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 was held March 17 - 18, 2005. A ruling in this case by the special master was received in May 2005 which dismissed OG&E and all Enogex parties named in these proceedings. This ruling has been appealed to the District Court of Wyoming. An oral argument on this appeal to the District Court was made on December 9, 2005 but there is no ruling in this case to date. The Company intends to vigorously defend this action. At this time, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

Will Price (Price I) – On September 24, 1999, various subsidiaries of 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 was held April 1, 2005. The Company intends to vigorously defend this action. At this time, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

Will Price (Price 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 was held April 1, 2005. The Company intends to vigorously defend this action. At this time, the Company is unable to provide an evaluation of the likelihood of an unfavorable outcome and an estimate of the amount or range of potential loss to the Company.

Agreement with Cheyenne Plains Gas Pipeline Company, L.L.C.

OERI and Cheyenne Plains Gas Pipeline Company, L.L.C. are parties to a firm transportation services agreement dated April 14, 2004. The Cheyenne Plains Pipeline provides interstate gas transportation services in Wyoming, Colorado and Kansas with a capacity of 560,000 decatherms/day ("Dth/day"). Effective January 1, 2006, the capacity on the Cheyenne Plains Pipeline increased to 730,000 Dth/day. OERI reserved 60,000 Dth/day of firm capacity on the Cheyenne Plains Pipeline for 10 years. Such reservation provides OERI access to significant additional natural gas supplies in the Rocky

Mountain production basins. OERI pays a demand fee of approximately $7.5 million annually for this capacity. OERI incurred a loss of approximately $3.6 million during 2005 related to its Cheyenne Plains' position as a result of unfavorable market conditions for the capacity primarily due to the 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. If the market conditions reflected in the current forward market price quotes continue for 2006, OERI expects to record a loss of approximately $1.4 million in 2006.

G.M. Oil Properties Litigation

On March 8, 2005, Enogex was served with a putative class action filed by G.M. Oil Properties, Inc. in the District Court of Comanche County, Oklahoma. The petition alleges that Enogex exercises a monopoly power with respect to its gathering facilities within the state of Oklahoma. The petition further alleges that, due to the alleged monopoly power, Enogex has caused damage to the plaintiff and other small gas producers and marketers. A settlement of this case has been reached with the named plaintiffs and the case brought by the named plaintiffs will be dismissed with prejudice. Pursuant to the settlement, a certain segment of gathering pipeline will be sold to G.M. Oil Properties with the Company recognizing the resulting gain of less than $0.1 million.

Pipeline Rupture

On May 10, 2005, a natural gas pipeline rupture occurred on an Enogex facility within the ANR Pipeline, Inc. ("ANR") plant site in Custer County, near Clinton, Oklahoma, resulting in an explosion and fire. Several companies have operations at the site which is operated by ANR, a subsidiary of El Paso Corporation. No injuries were reported as a result of the incident. The Enogex pipeline equipment at the site was isolated and the flow of gas to the site was shut off. Investigation of the incident and the cause thereof is ongoing. The site is near the location of the former Enogex Custer gas processing plant closed in 2002. Although temporarily disrupted, pipeline operations continue at the location. It is anticipated that any third party damages related to this incident will not be material to the Company as they will be covered by insurance following payment of the deductible, which deductible has been accrued in the Company's Consolidated Financial Statements.

Farris Buser Litigation

On July 22, 2005, Enogex along with certain other unaffiliated co-defendants were served with a purported class action which had been filed on February 7, 2005 by Farris Buser and other named plaintiffs in the District Court of Canadian County, Oklahoma. The plaintiffs' own royalty interests in certain oil and gas producing properties and allege they have been under-compensated by the named defendants, including the Enogex companies, relating to the sale of liquid hydrocarbons recovered during the transportation of natural gas from the plaintiffs' wells. The plaintiffs' assert breach of contract, implied covenants, obligation, fiduciary duty, unjust enrichment, conspiracy and fraud causes of action and claim actual damages in excess of $10,000, plus attorneys' fees and costs, and punitive damages in excess of $10,000. The Enogex companies filed a motion to dismiss which was granted on November 18, 2005, subject to the plaintiffs' right to conduct discovery and the possible re-filing of their allegations in the petition against Enogex companies. The court-established re-filing deadline has been extended by order of the court until May 17, 2006. On September 19, 2005, the co-defendants, BP America, Inc. and BP America Production Co., filed a cross claim against Enogex Products Corporation ("Products") seeking indemnification and/or contribution from Products based upon the 1997 sale of a third party interest in one of Products natural gas processing plants. Based on its investigation to date, the Company believes these claims and cross claims in this lawsuit are without merit and intends to vigorously defend this case.

Kaiser-Francis Litigation

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

On January 3, 2006, the trial court granted OG&E's motion for partial summary judgment on Plaintiff's tort claim. This ruling struck from the lawsuit Plaintiff's claim of (i) approximately $4.7 million in tort damages;

and (ii) approximately $11 million in punitive damages. On January 13, 2006, at a court-ordered settlement conference, a settlement was reached in the Blaine County case whereby OG&E agreed to pay $8.9 million to Kaiser-Francis. The suit was dismissed with prejudice on January 18, 2006 and this case is now closed. OG&E believes that the settlement amount is recoverable through its regulated electric rates.

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

Calpine Corporation Bankruptcy

Calpine Corporation, Calpine Energy Services, L.P., and several other affiliates (collectively "Calpine") voluntarily filed for Chapter 11 bankruptcy protection from creditors on December 20, 2005 (Case No. 05-60200 (BRL)) United States Bankruptcy Court, S.D. of New York. Enogex provides natural gas transportation services pursuant to long term contracts to two Calpine-owned power generation plants in Oklahoma. At this point, Calpine is continuing to operate the plants, request services pursuant to the contracts and make the monthly payments under its agreements with Enogex; however, whether Calpine in its bankruptcy proceedings will ultimately reject these agreements with Enogex is unknown.

A Calpine-owned power generation plant in Oklahoma is contractually obligated to provide capacity and energy to OG&E. The Calpine plant also pays, through the Southwest Power Pool ("SPP"), for transmission services provided by OG&E. OG&E expects both arrangements to remain in effect; however, whether Calpine in its bankruptcy proceedings will ultimately reject these agreements with OG&E is unknown.

Guarantees

At December 31, 2005 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 $16.8 million of collateral to satisfy its obligation under its financial and physical contracts.

Environmental Laws and Regulations

Approximately $5.0 million of the Company's capital expenditures budgeted for 2006 are to comply with environmental laws and regulations. The Company's management believes that all of its operations are in substantial compliance with present federal, state and local environmental standards. It is estimated that the Company's total expenditures for capital, operating, maintenance and other costs to preserve and enhance environmental quality will be approximately $59.7 million during 2006 as compared to approximately $67.0 million in 2005. The Company continues to evaluate its environmental management systems to ensure compliance with existing and proposed environmental legislation and regulations and to better position itself in a competitive market.

OG&E

Air

On March 10, 2005, the Environmental Protection Agency ("EPA") published the Clean Air Interstate Rule ("CAIR"). This rule is intended to control sulfur dioxide ("SO2") and nitrogen oxide ("NOX") emissions from utility boilers in order to minimize the interstate transport of air pollution. The state of Oklahoma is not listed as one of the states affected by the rule.

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

On June 15, 2005, the EPA issued final amendments to its 1999 regional haze rule. These regulations are intended to protect visibility in national parks and wilderness areas ("Class I areas") throughout the United States. In Oklahoma, the Wichita Mountains are the only area covered under the regulation. However, Oklahoma's impact on parks in other states must also be evaluated. Sulfates and nitrate aerosols (both emitted from coal-fired boilers) can lead to the degradation of visibility. The state of Oklahoma has joined with eight other central states and has begun to finalize the process of determining what, if any, impact emission sources in Oklahoma have on national parks and wilderness areas.

In September 2005, the Oklahoma Department of Environmental Quality ("ODEQ") informally notified affected utilities that they would be required to perform a study to determine their impact on visibility in Class I areas. If an impact from affected OG&E facilities is determined, OG&E must propose emission controls to meet ODEQ requirements. Federal requirements are currently being incorporated into the state implementation plan through rulemaking. The study and proposed reductions or controls, if needed, must be submitted to the ODEQ by December 2006. OG&E will have five years from the date of approval of a compliance plan to institute any required reductions. If an impact is determined and the regulations remain in effect, then significant capital and operating expenditures will be required for OG&E's Sooner, Muskogee, Seminole and Horseshoe Lake generating stations.

In 1997, the EPA finalized revisions to the ambient ozone and fine particulate standards. After a court challenge, which delayed implementation, the EPA has now begun to finalize the implementation process. Based on the most recent monitoring data, the EPA has designated Oklahoma "in attainment" with both standards. However, on June 21 and 22, 2005, both Tulsa and Oklahoma City experienced high levels of ozone. If Tulsa and Oklahoma City continue to have elevated ozone levels for the next three ozone seasons, they could face redesignation to non-attainment status. To help avoid redesignation, both Tulsa and Oklahoma City have entered into an "Early Action Compact" with the EPA whereby voluntary measures will be enacted to reduce ozone.

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

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

The 1990 Clean Air Act includes an acid rain program to reduce SO2 emissions. Reductions were obtained through a program of emission (release) allowances issued by the EPA to power plants covered by the acid rain program. Each allowance is worth one ton of SO2 released from the smokestack. Plants may only release as much SO2 as they have allowances. Allowances may be banked and traded or sold nationwide. Beginning in 2000, OG&E became subject to more stringent SO2 emission requirements in Phase II of the acid rain program. These lower limits had no significant financial impact due to OG&E's earlier decision to burn low sulfur coal. In 2005, OG&E's SO2 emissions were well below the allowable limits.

The EPA allocated SO2 allowances to OG&E starting in 2000 and OG&E started banking allowances in 2001. In December 2005, OG&E sold 3,700 allowances for approximately $5.7 million. This transaction resulted in an increase in cash and a decrease in fuel clause under recoveries with no impact to earnings as the proceeds from these sales have been returned to OG&E's customers. In February 2006, OG&E sold 6,312 allowances for approximately $8.9 million. See Note 15 for a discussion of the SO2 allowance joint filing made in February 2006 which proposes how the proceeds from the sale of SO2 allowances should be accounted for in the future.

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

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

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 2005, OG&E obtained refunds of approximately $1.0 million from its recycling efforts. This figure does not include the additional savings gained through the reduction and/or avoidance of disposal costs and the reduction in material purchases due to the reuse of existing materials. Similar savings are anticipated in future years.

Water

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

Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of any cooling water intake structure reflect the "best available technology" for minimizing environmental impacts. The EPA 316(b) rules for existing facilities became effective July 23, 2004. OG&E has engaged a consultant who has developed the required documentation for four OG&E facilities. These documents were submitted to the state agency on December 7, 2005 for review and approval. The Company has also provided the state of Oklahoma with information and requests that, if approved by the state, may reduce the impact of the 316(b) rules on the Company because if the Company's position is approved, three of the four Company facilities would not be required to comply with the 316(b) rules. Depending on the ultimate analysis and final determinations regarding the 316(b) rules, capital and/or operating costs may increase at any affected OG&E generating facility.

Enogex

The construction and operation of pipelines, plants and other facilities for transporting, processing, compressing 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 legal counsel and other appropriate experts to assess the claim. If in management's opinion, the Company has incurred a probable loss as set forth by accounting principles generally accepted in the United States, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. Management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

15. 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, 2005 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. In addition, the Energy Policy Act of 2005 enacted the Public Utility Holding Company Act of 2005, which in turn granted to the FERC access to the books and records of the Company and its affiliates as the FERC deems relevant to costs incurred by OG&E or necessary or appropriate for the protection of utility customers with respect to jurisdictional rates.

Completed Regulatory Matters

2002 Settlement Agreement

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

Acquisition of Power Plant

On July 9, 2004, OG&E completed the acquisition of NRG McClain LLC's 77 percent interest in the 520 MW McClain Plant. This transaction was intended to satisfy the requirement in the Settlement Agreement to acquire New Generation. The McClain Plant, which includes natural gas-fired combined cycle combustion turbine units, is located near Newcastle, Oklahoma in McClain County, Oklahoma. The McClain Plant began operating in 2001. The owner of the remaining 23 percent interest in the McClain Plant is the Oklahoma Municipal Power Authority.

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

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

OG&E expects the addition 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. 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 achieve at least $75.0 million in savings during this period.

Enogex FERC Section 311 2001 Rate Case

Pursuant to a settlement accepted by the FERC in May 2003 to resolve Enogex's 2001 Section 311 rate case, Enogex assessed a fee under certain market conditions for processing customer gas gathered behind processing plants so that it met the heating value standards of natural gas transmission pipelines ("default processing fee"). Pursuant to Enogex's Statement of Operating Conditions ("SOC") that was effective through September 30, 2004, if Enogex's annual processing gross margin exceeded a specified threshold, Enogex was 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. In June 2004, Enogex billed default processing fees of approximately $0.2 million, which was recorded as deferred revenue. Based on the processing gross margin for 2004, these default processing fees billed to customers were recorded as deferred revenue and were refunded or credited to customers by April 30, 2005.

Enogex FERC Section 311 2004 Rate Case and related FERC dockets and 2006 Fuel Filing

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. As a result, effective October 1, 2004, the FERC regulates Enogex's Section 311 transportation and any regulation of gathering is pursuant to Oklahoma statute.

On September 30, 2004, Enogex made its required triennial filing at the FERC to update its Section 311 maximum interruptible transportation rate. On September 29, 2004, Enogex filed an updated fuel factor with the FERC for the last quarter of 2004. Finally, on November 15, 2004, Enogex filed its annual updated fuel factor for fuel year 2005 (calendar year 2005).

Various parties intervened and protested the four filings but, after three technical conferences and various settlement discussions, reached a unanimous settlement that the FERC approved without modification or condition, by order of September 19, 2005. The Settlement established new maximum interruptible Section 311 zonal rates for an East Zone and a West Zone on the Enogex system, confirmed that Enogex could unbundle its gathering and transportation services and permitted the fuel factor percentages for the last quarter of 2004 and for fuel year 2005 to become effective, as filed. The FERC order concluded all four proceedings which resulted in no refunds being due. Because the FERC requires all intrastate pipeline offering 311 service to file a rate case every three years, Enogex must file its next rate case no later than October 1, 2007.

As required by the fuel tracker provisions of the SOC, Enogex made its annual fuel filing for the 2006 fuel year on November 15, 2005. As agreed in the Settlement, the fuel filing for the first time proposed an East Zone fuel percentage and a West Zone fuel percentage to be recalculated annually to replace the system-wide fuel percentage previously calculated annually for the whole Enogex system. Four parties moved to intervene. One party posed questions about the filing that Enogex answered on January 19, 2006. The FERC Staff later served data requests that Enogex answered on February 17, 2006. The FERC has not yet acted on the filing.

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

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

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

Security Enhancements

On April 8, 2002, 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. 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. On December 21, 2004, the OCC issued an order approving the security rider. OG&E expects to implement the security rider by mid-year 2006.

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 cogeneration credit rider expired December 31, 2004. On October 29, 2004, the OCC Staff and other parties filed responsive testimony. Hearings in this case were held on November 15, 2004, at which time the administrative law judge recommended approval of the proposed cogeneration credit rider. On December 21, 2004, the OCC issued an order approving a new cogeneration credit rider which lowered electric bills by approximately $80 million in 2005. Any 2005 over/under recovery of the cogeneration credit rider is automatically included in the 2006 rider. In December 2005, the OCC order in OG&E's recently completed rate case authorized a new

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cogeneration credit rider effective January 2006. The 2006 cogeneration credit rider is approximately $78.7 million and the 2005 under recovery was approximately $3.7 million.

OG&E Oklahoma Rate Case Filing

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

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

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

As provided in the 2002 Settlement Agreement, OG&E had the right to accrue a regulatory asset, for a period not to exceed 12 months subsequent to the completion of the acquisition and operation of the McClain

Plant, consisting of the non-fuel operation and maintenance expenses, depreciation, cost of debt associated with the investment and ad valorem taxes. OG&E completed its acquisition of the McClain Plant on July 9, 2004. Accordingly, OG&E ceased accruing various operating and related costs associated with the McClain Plant as a regulatory asset on July 8, 2005. At December 31, 2005, the actual incurred expenses included in the McClain Plant regulatory asset were approximately $24.9 million. Such costs will be recovered over a four-year time period as authorized in the OCC rate order beginning in January 2006. The OCC authorized approximately $15.5 million of the $24.9 million regulatory asset to be included in OG&E's rate base for purposes of earning a return.

Pending Regulatory Matters

Review of OG&E's Fuel Adjustment Clause for Calendar Year 2003 and 2004

The OCC routinely audits activity in OG&E's fuel adjustment clause for each calendar year. On March 18, 2005, the OCC Staff filed Cause No. PUD 200500140 regarding "Application of the Public Utility Division Director for Public Hearing to Review and Monitor OG&E's Fuel Adjustment Clause for Calendar Year 2003." On June 10, 2005, the OCC voted to combine this case with OG&E's recently completed rate case discussed above. On August 25, 2005, the OCC Staff filed Cause No. PUD 200500327 regarding "Application of the Public Utility Division Director for Public Hearing to Review and Monitor OG&E's Fuel Adjustment Clause for Calendar Year 2004." On September 27, 2005, the OCC consolidated

these two proceedings into one proceeding. Intervenors in this proceeding include the OIEC, AES, Redbud and PowerSmith. Hearings in this proceeding are scheduled to begin May 11, 2006.

Competitive Bidding and Prudence Reviews for Electric Utility Providers

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

Power Purchase Agreement Filings

On February 4, 2005, Chermac Energy Corporation ("Chermac") and Sleeping Bear, LLC filed an application at the OCC (Cause No. PUD 200500059) seeking establishment of purchased power rates and a power purchase agreement with OG&E pursuant to PURPA for Chermac's proposed Buffalo/Sleeping Bear wind project. On April 28, 2005, Chermac and Sleeping Bear, LLC filed a second application at the OCC (Cause No. PUD 200500177) seeking establishment of purchased power rates and a power purchase agreement with OG&E pursuant to PURPA for Chermac's proposed Sleeping Bear South wind project. On September 15, 2005, the ALJ heard arguments on why the application should or should not be dismissed. On October 20, 2005, the ALJ suspended the current procedural schedule so that the parties involved in the proceeding could enter into negotiations. Subsequently, Chermac effectively designated Invenergy Wind LLC as its agent for settlement discussions. On December 22, 2005, the Company issued a press release announcing that OG&E had entered into a non-binding letter of intent to purchase a 120 MW wind farm planned for construction in northwestern Oklahoma. Invenergy Wind Development Oklahoma LLC ("Invenergy LLC") would develop the new wind power-generation facility to be owned and operated by OG&E. The wind farm, north of Woodward in Harper County, is expected to cost approximately $195 million, including the cost of transmission interconnection facilities. A definitive Agreement To Engineer, Procure and Construct Wind Generation Energy System ("EPC Contract") was reached on February 20, 2006, subject to various conditions. Those conditions include agreement by the parties as to certain exhibits to the EPC Contract, approval of the EPC Contract by the OG&E Board of Directors and approval of the EPC Contract by the Manager of Invenergy LLC, all of which have to be completed on or before March 13, 2006. In addition, 90 days subsequent to the occurrence of these events, OG&E or Invenergy LLC have the unilateral right to terminate the EPC Contract if certain additional events have not occurred, including the following: (i) OCC approval of the terms of the EPC Contract and of a recovery rider providing OG&E the opportunity to recover all costs associated with the wind facility, including transmission interconnection and transmission upgrade costs; (ii) completion by the SPP of all necessary transmission studies; (iii) Invenergy LLC's acquisition of certain land agreements; (iv) Invenergy LLC's execution of a contract acceptable to OG&E with a balance of work contractor; and (v) Invenergy LLC's acquisition of certain permits. If all of these conditions are met, the new wind farm is expected to be constructed and producing power on or before December 31, 2006. OCC hearings are expected to occur in April 2006.

OG&E Arkansas Rate Case Filing

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

OG&E SO2 Allowance Filing

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

Southwest Power Pool

OG&E is a member of the SPP, the regional reliability organization for all or parts of Oklahoma, Arkansas, Kansas, Louisiana, New Mexico, Mississippi, Missouri and Texas. 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 an RTO. In a FERC order dated October 1, 2004, the SPP was granted RTO status, subject to the SPP submitting a further compliance filing. On January 25, 2005, the FERC issued an order on compliance filing stating that the November 1, 2004 SPP compliance filing satisfied the October 1 FERC order. The approval of the SPP RTO application is not expected to significantly impact the Company's consolidated financial results.

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

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

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

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

Market-Based Rate Authority

On December 22, 2003, 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. One party, Redbud, protested the OG&E and OERI filing and proposed that the FERC require OG&E to adopt an economic dispatch program as a means to mitigate OG&E's and OERI's generation market power. On March 15, 2005, OG&E and OERI responded to Redbud's protest. In that response OG&E and OERI reiterated that the information they initially filed demonstrates that they cannot exercise market power and that Redbud's proposal is beyond the scope of the proceeding. Another party, AES, has requested intervention in this case in protest. In June 2005, the FERC granted the Redbud and AES interventions.

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

Department of Energy Blackout Report

On April 5, 2004, the U.S. Department of Energy issued its final report regarding the August 14, 2003 electric blackout in the eastern United States, which did not have an adverse affect on 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.

National Energy Legislation

In August 2005, Congress passed and the President signed into law a comprehensive energy bill, portions of which are of interest to the Company and to the industry. There are several provisions in the bill that have a positive impact on the Company. Provisions minimizing the risk of future uneconomic purchased power contracts forced on the Company under PURPA, tax incentives for investment in electric transmission and gas pipeline systems, mandatory reliability requirements by the North American Electric Reliability Council with oversight by the FERC and improved FERC siting authority for construction of electric transmission in disputed areas are included in the new law. Another significant provision for the utility industry is the repeal of the Public Utility Holding Company Act of 1935. This provision has minimal impact on the current operations of the Company. The FERC is in the process of developing regulations and policies mandated by the new energy act, some of which could have significance for electric utilities such as OG&E. In particular, OG&E will closely monitor the FERC's implementation of the new statute's conditional elimination of utilities' obligation to purchase power from cogenerators. Similarly, OG&E will closely monitor the FERC and U.S. Department of Energy proceedings with

regard to rules on the new mandatory reliability regime governing all electric generators, new transmission incentives and the concept of economic or efficient dispatch.

State Legislative Initiatives

Oklahoma

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

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

Arkansas

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

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

16. 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:

(In millions)	**2005** Carrying Amount	**2005** Fair Value	2004 Carrying Amount	2004 Fair Value
Price Risk Management Assets				
Energy Trading Contracts	**$ 125.4**	**$ 125.4**	$ 62.8	$ 62.8
Interest Rate Swaps	**0.1**	**0.1**	7.9	7.9
Price Risk Management Liabilities				
Energy Trading Contracts	**$ 120.1**	**$ 120.1**	$ 42.2	$ 42.2
Interest Rate Swaps	**0.1**	**0.1**	---	---
Long-Term Debt				
Senior Notes	**$ 587.8**	**$ 612.2**	$ 810.9	$ 864.1
Industrial Authority Bonds	**135.4**	**135.4**	135.4	135.4
Enogex Notes – continuing operations	**407.6**	**441.2**	447.1	482.1
Enogex Notes – discontinued operations	---	---	67.0	71.0
Other	**220.0**	**220.0**	---	---

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, 2005 and 2004, 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, 2005. Our audits also included the financial statement schedule listed in the Index at Item 15. These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits.

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of OGE Energy Corp. at December 31, 2005 and 2004, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2005, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth herein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of OGE Energy Corp.'s internal control over financial reporting as of December 31, 2005, based on criteria established in Internal Control—Integrated Framework issued by the

Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 21, 2006 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 21, 2006

Supplementary Data

Interim 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)(B)	**2005**	**$ 1,653.1**	**$ 1,681.5**	**$ 1,339.1**	**$ 1,274.5**
	2004	1,397.8	1,319.3	1,150.5	1,036.8
Operating income (A)(B)	**2005**	**$ 40.4**	**$ 190.1**	**$ 77.0**	**$ 23.0**
	2004	34.6	161.1	80.3	27.8
Net income (loss)(B)	**2005**	**$ 56.1**	**$ 111.1**	**$ 38.5**	**$ 5.3**
	2004	9.7	94.6	39.0	10.2
Basic earnings per average common share	**2005**	**$ 0.62**	**$ 1.23**	**$ 0.43**	**$ 0.06**
	2004	0.10	1.08	0.44	0.12
Diluted earnings per average common share	**2005**	**$ 0.62**	**$ 1.22**	**$ 0.42**	**$ 0.06**
	2004	0.10	1.07	0.44	0.12

(A) These amounts have been restated due to the sales of EAPC and Enerven being reported as discontinued operations during 2005 and 2004.
(B) In January 2005, a cogeneration credit rider was implemented at OG&E as part of the Oklahoma retail customer electric rates in order to return purchase power capacity payment reductions and any change in operating and maintenance expense related to cogeneration previously included in base rates to OG&E's customers. This rider resulted in the seasonal over or under collection of revenues as the rider is based on an equal monthly amount kwh usage as compared to actual kwh usage. Due to the seasonal rates of OG&E's electric sales, this resulted in a temporary over collection of operating revenues in excess of the reduction in operating and maintenance expense for the first and second quarters of 2005 of approximately $5.9 million ($3.6 million after tax or $0.04 per share) and a temporary under collection of operating revenues in excess of the reduction in operating and maintenance expense for the third quarter of 2005 of approximately $10.0 million ($6.1 million after tax or $0.07 per share). In August 2005, OG&E determined that its net income should not be affected by over or under collections on a temporary or permanent basis, and accordingly, any difference should be deferred as a regulatory asset or liability. As a result, in order to better reflect the purchase power capacity payment reductions and any change in operating and maintenance expense related to cogeneration from January 1, 2005 to September 30, 2005, OG&E recorded a regulatory asset of approximately $4.1 million in current assets as Prepayments and Other in the Consolidated Balance Sheet and a corresponding $4.1 million increase to Operating Revenues in the Consolidated Statement of Income. Going forward, OG&E expects any over or under collections related to the cogeneration credit rider to be reflected as a regulatory asset or liability. The balance of the cogeneration credit rider under recovery was approximately $3.7 million at December 31, 2005. Any 2005 over/under recovery of the cogeneration credit rider is automatically included in the 2006 rider. In December 2005, the OCC order in OG&E's recently completed rate case authorized a new cogeneration credit rider effective January 2006. The 2006 cogeneration credit rider is approximately $78.7 million and the 2005 under recovery was approximately $3.7 million.

Dividends

COMMON STOCK

Common quarterly dividends paid (as declared) in 2005, 2004, and 2003 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	P2	A2	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

	2005		2004	
NEW YORK STOCK EXCHANGE	**High**	**Low**	High	Low
Common				
First Quarter	**$ 27.59**	**$ 25.15**	$ 26.70	$ 23.03
Second Quarter	**29.22**	**26.11**	26.80	22.85
Third Quarter	**30.60**	**27.74**	26.48	24.10
Fourth Quarter	**28.60**	**24.41**	26.95	25.17

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 recently completed fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934).

Management's Report on Internal Control Over Financial Reporting

The management of 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, 2005. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework. Based on our assessment, we believe that, as of December 31, 2005, the Company's internal control over financial reporting is effective based on those criteria.

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

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

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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, 2005, 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, 2005, 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, 2005, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets and statements of capitalization of OGE Energy Corp. as of December 31, 2005 and 2004, 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, 2005 of OGE Energy Corp. and our report dated February 21, 2006 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 21, 2006

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. The Company will also include in its proxy statement the audit committee financial expert.

Item 11. Executive Compensation.

On February 22, 2006 the Compensation Committee (the "Committee") of the Board of Directors of OGE Energy Corp. (the "Company") took certain actions regarding executive officer compensation. Set forth below is a description of the actions taken.

Approve Payout of 2005 Annual Incentive Awards

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

The amount of the award for each executive officer was expressed as a percentage of base salary (the "targeted amount"), with the officer having the ability, depending upon achievement of the corporate goals, to receive from 0 percent to 150 percent of such targeted amount. For 2005, the targeted amount ranged from 25 percent to 80 percent of base salary. Payouts of the award were to be in cash and were dependent entirely on the achievement of the corporate goals.

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

For Mr. Steven E. Moore, Chairman and Chief Executive Officer and Mr. Peter B. Delaney, Executive Vice President and Chief Operating Officer, the two most senior executive officers of the Company at the time the corporate goals were established, the corporate goals were based: (i) 50 percent on a Company consolidated earnings per share target established by the Committee (the "Earnings Target"), (ii) 25 percent on a combined operating and maintenance expense and capital expenditure target for the Company and OG&E established by the Committee (the "O&M/Capital Target"), and (iii) 25 percent on consolidated net income of Enogex and its subsidiaries (the "Unregulated Income Target"). At least two of these three corporate goals were used in establishing the corporate goals for all other executive officers. However, the weighting of the corporate goals was slightly different for the remaining executive officers. For four executive officers, the corporate goals were based 50 percent on the Earnings Target and 50 percent on the O&M/Capital Target, for five executive officers, the corporate goals were based 40 percent on the Earnings Target, 40 percent on the Unregulated Income Target and 20 percent on the return on invested capital of Enogex (the "ROIC Target") and for two executive officers, the corporate goals were based 40 percent on the Earnings Target, 30 percent on the Unregulated Income Target, 20 percent on the Earnings Before Interest and Taxes Target and 10 percent on the OGE Energy Resources, Inc. Operational Measures Target. For the remaining executive officers, the corporate goals were based 50 percent on the Earnings Target, 30 percent on the O&M/Capital Target and 20 percent on the Unregulated Income Target.

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

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

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

Approve Payout of 2003 Long-Term Incentive Awards

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

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

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

Establishment of 2006 Annual Incentive Awards

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

At its February 22, 2006 meeting, the Company established the performance goals for such awards. For Mr. Steven E. Moore, Chairman and Chief Executive Officer and Mr. Peter B. Delaney, Executive Vice President and Chief Operating Officer, the two most senior executive officers of the Company at the time the corporate goals were established, the corporate goals were based: (i) 50 percent on a Company consolidated earnings per share target established by the Committee (the “Earnings Target”), (ii) 25 percent on a combined operating and maintenance expense and capital expenditure target for the Company and OG&E established by the Committee (the “O&M/Capital Target”), and (iii) 25 percent on consolidated net income of Enogex and its subsidiaries (the “Unregulated Income Target”). At least two of these three corporate goals were used in establishing the corporate goals for all other executive officers. However, the weighting of the corporate goals was slightly different for the remaining executive officers. For two executive officers, the corporate goals were based 50 percent on the Earnings Target and 50 percent on the O&M/Capital Target, for six executive officers, the corporate goals were based 40 percent on the Earnings Target, 40 percent on the Unregulated Income Target and 20 percent on the return on invested capital of Enogex (the “ROIC Target”) and for one executive officer, the corporate goals were based 40 percent on the Earnings Target, 37.5 percent on the Unregulated Income Target, 20 percent on the ROIC Target and 2.5 percent on the OGE Energy Resources, Inc. Operational Measures Target. For the remaining executive officers, the corporate goals were based 50 percent on the Earnings Target, 30 percent on the O&M/Capital Target and 20 percent on the Unregulated Income Target.

Establishment of Long-Term Awards

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

For 2006, the Committee made awards of performance units. The number of performance units granted was determined by taking the amount of the executive's long-term award to be delivered in performance units (adjusted on a present value basis), as determined by the Committee, and dividing that amount by the closing price for the Company's Common Stock on February 8, 2006 with a vesting factor applied. This resulted in executive officers receiving performance units with an expected value at the date of grant of from 30 percent to 150 percent of their 2006 base salaries. The value of the performance units is substantially dependent upon the changing value of the Company's Common Stock in the marketplace. Each executive officer is entitled to receive from 0 percent to 200 percent of the performance units contingently awarded to the executive depending upon corporate performance. At its February 22, 2006 meeting, the Committee determined that for 75 percent of the performance units, this corporate performance will be based on the Company's total shareholder return over a three-year period (defined as share price increase plus dividends paid, divided by share price at beginning of the period) measured against the total shareholder return for such period by a peer group selected by the Committee. For the remaining 25 percent of the performance units, the corporate performance will be based upon the growth in the Company's earnings per share compared to specified targets selected by the Committee.

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

Named Executive	Performance Units
Steven E. Moore	59,288
Peter B. Delaney	31,012
James R. Hatfield	15,967
Steven R. Gerdes	3,724
Danny P. Harris	7,915

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

Equity Compensation Plan Information

The following table provides certain information as of December 31, 2005 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)	2,139,376	$22.20	2,014,369 (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 the 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, 2006. 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, 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, 2005 and 2004
- Consolidated Statements of Capitalization at December 31, 2005 and 2004
- Consolidated Statements of Income for the years ended December 31, 2005, 2004 and 2003
- Consolidated Statements of Retained Earnings for the years ended December 31, 2005, 2004 and 2003
- Consolidated Statements of Comprehensive Income for the years ended December 31, 2005, 2004 and 2003
- Consolidated Statements of Cash Flows for the years ended December 31, 2005, 2004 and 2003
- 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	130

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

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 filed August 20, 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)
2.13	Stock purchase agreement dated September 21, 2005 by and between Enogex Inc. and Atlas Pipeline Partners, L.P. (Filed as Exhibit 10.01 to OGE Energy's Form 8-K filed September 27, 2005 (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. (Filed as Exhibit 3.02 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

4.01	Trust Indenture 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 filed October 24, 1995 (File No. 1-1097) and incorporated by reference herein)
4.03	Supplemental Indenture No. 2, dated as of July 1, 1997, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed July 17, 1997 (File No. 1-1097) and incorporated by reference herein)
4.04	Supplemental Indenture No. 3, dated as of April 1, 1998, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed April 16, 1998 (File No. 1-1097) and incorporated by reference herein)
4.05	Supplemental Indenture No. 4, dated as of October 15, 2000, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.02 to OG&E's Form 8-K filed 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 filed 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 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 November 12, 2004 (File No. 1-12579) and incorporated by reference herein)
4.10	Supplemental Indenture No. 7 dated as of January 1, 2006 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.08 to OG&E's Form 8-K filed January 6, 2006 (File No. 1-1097) and incorporated by reference herein)
10.01	Form of Change of Control Agreement for Officers of the Company and 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. (Filed as Exhibit 10.07 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)
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 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	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)
10.14	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)
10.15	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)
10.16	Fifth Amendment to Loan Agreement, dated April 6, 2005 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, 2005 (File No. 1-12579) and incorporated by reference herein)
10.17	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)
10.18	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)
10.19	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)
10.20	Amendment No. 1 to Company's 2003 Stock Incentive Plan. (Filed as Exhibit 10.23 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)
10.21	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.] (Filed as Exhibit 10.24 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

10.22	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. (Filed as Exhibit 10.25 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)
10.23	Amendment No. 5 to the OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.26 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)
10.24	Directors' Compensation.
10.25	Executive Officer Compensation.
10.26	Form of Non-Qualified Stock Option Agreement under 2003 Stock Incentive Plan. (Filed as Exhibit 10.29 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)
10.27	Form of Performance Unit Agreement under 2003 Stock Incentive Plan. (Filed as Exhibit 10.30 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)
10.28	Form of Restricted Stock Agreement under 2003 Stock Incentive Plan. (Filed as Exhibit 10.31 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

10.29	Form of Split Dollar Agreement. (Filed as Exhibit 10.32 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)
10.30	Credit agreement dated September 30, 2005, by and between the Company, Wachovia Bank, National Association, JPMorgan Chase Bank, Citibank, N.A., The Royal Bank of Scotland plc and Union Bank of California, N.A. (Filed as Exhibit 99.01 to the Company's Form 8-K filed October 5, 2005 (File No. 1-12579) and incorporated by reference herein)
10.31	Credit agreement dated September 30, 2005, 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 the Company's Form 8-K filed October 5, 2005 (File No. 1-12579) and incorporated by reference herein)
10.32	Consulting agreement dated as of December 1, 2005, by and between the Company and Jack T. Coffman. (Filed as Exhibit 10.01 to OGE Energy's Form 8-K filed November 21, 2005 (File No. 1-12579) and incorporated by reference herein)
10.33	Amendment No. 6 to the OGE Energy Corp. Restoration of Retirement Income Plan.
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.

99.02	Copy of OCC order 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 8-K filed December 16, 2005 (File No. 1-12579) and incorporated by reference herein)
	<u>Executive Compensation Plans and Arrangements</u>
10.01	Form of Change of Control Agreement for Officers of the Company and 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)
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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. (Filed as Exhibit 10.07 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File

No. 1-12579) and incorporated by reference herein)

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)
10.12	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)
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10.25	Executive Officer Compensation.
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10.27	Form of Performance Unit Agreement under 2003 Stock Incentive Plan. (Filed as Exhibit 10.30 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

10.28	Form of Restricted Stock Agreement under 2003 Stock Incentive Plan. (Filed as Exhibit 10.31 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)
10.29	Form of Split Dollar Agreement. (Filed as Exhibit 10.32 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)
10.32	Consulting agreement dated as of December 1, 2005, by and between the Company and Jack T. Coffman. (Filed as Exhibit 10.01 to OGE Energy's Form 8-K filed November 21, 2005 (File No. 1-12579) and incorporated by reference herein)
10.33	Amendment No. 6 to the OGE Energy Corp. Restoration of Retirement Income Plan.

OGE ENERGY CORP.

SCHEDULE II - Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts	Deductions	Balance at End of Period
	(In millions)				
Year Ended December 31, 2003					
Reserve for Uncollectible Accounts	$ 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
Year Ended December 31, 2005					

Reserve for Uncollectible Accounts	$ 4.5	$ 3.1	$ ---	$ 3.9 (A)	$ 3.7

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

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Oklahoma City, and State of Oklahoma on the 24th day of February, 2006.

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 24, 2006
/ s / James R. Hatfield James R. Hatfield	Principal Financial Officer; and	February 24, 2006
/ s / Scott Forbes Scott Forbes	Principal Accounting Officer.	February 24, 2006
Herbert H. Champlin	Director;	
Luke R. Corbett	Director;	
William E. Durrett	Director;	
John D. Groendyke	Director;	
Robert Kelley	Director;	
Linda P. Lambert	Director;	
Robert Lorenz	Director;	
Ronald H. White, M.D.	Director; and	
J. D. Williams	Director.	
/ s / Steven E. Moore By Steven E. Moore (attorney-in-fact)		February 24, 2006

Exhibit 10.24

OGE ENERGY CORP.
DIRECTORS' COMPENSATION

For 2005, compensation of non-officer directors of the Company included an annual retainer fee of $75,000, of which $24,000 was paid monthly in cash and $51,000 was deposited in the director's account under the deferred compensation plan in December 2005. For 2006, the monthly portion payable in cash was increased to $30,000. Also, 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. Also, the Compensation Committee is expected to consider director compensation for 2007 at its meeting in November 2006. If the Committee at that meeting authorizes a payment of a portion of the director's compensation be deposited in the director's account under the deferred compensation plan (i.e., the $51,000 above) and the deposit is made in 2006, such amount will be reported as part of the director's 2006 compensation.

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 2005, 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 10.25

OGE ENERGY CORP.
EXECUTIVE OFFICER COMPENSATION

Executive Compensation

On December 13, 2005, the Compensation Committee (the "Committee") of the OGE Energy Corp. board of directors took actions setting executives' salaries, annual bonus targets and long-term compensation awards for 2006. Executive compensation was set by the Committee after consideration of, among other things, individual performance and market-based data on compensation for executives with similar duties. Payouts of 2006 annual bonus targets and long-term awards are dependent on achievement of specified goals that will be established by the Committee at a subsequent meeting, and no officer is assured of any payout. Set forth below is a description of the actions taken.

Salary

The Committee established the base salaries for its senior executive group. The salaries for 2006 for the current OGE Energy officers who are expected to be named in the Summary Compensation Table in OGE Energy's 2006 Proxy Statement (the "Named Executive Officers") are as follows:

Named Executive Officer	2006 Base Salary
Steven E. Moore, Chairman, President and Chief Executive Officer	$ 780,000
Peter B. Delaney, Executive Vice President and Chief Operating Officer	$ 510,000
James R. Hatfield, Senior Vice President and Chief Financial Officer	$ 370,700
Danny P. Harris, President, Unregulated Business	$ 284,000
Steven R. Gerdes, Vice President, Utility Operations	$ 210,000

Establishment of 2006 Annual Incentive Awards

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

At its February 22, 2006 meeting, the Company established the performance goals for such awards. For Mr. Steven E. Moore, Chairman and Chief Executive Officer and Mr. Peter B. Delaney, Executive Vice President and Chief Operating Officer, the two most senior executive officers of the Company at the time the corporate goals were established, the corporate goals were based: (i) 50 percent on a Company consolidated earnings per share target established by the Committee (the "Earnings Target"), (ii) 25 percent on a combined operating and maintenance expense and capital expenditure target for the Company and OG&E established by the Committee (the "O&M/Capital Target"), and (iii) 25 percent on consolidated net income of Enogex and its subsidiaries (the "Unregulated Income Target"). At least two of these three corporate goals were used in establishing the corporate goals for all other executive officers. However, the weighting of the corporate goals was slightly different for the remaining executive officers. For two executive officers, the corporate goals were based 50 percent on the Earnings Target and 50 percent on the O&M/Capital Target, for six executive officers, the corporate goals were based 40 percent on the Earnings Target, 40 percent on the Unregulated Income Target and 20 percent on the return on invested capital of Enogex (the "ROIC Target") and for one executive officer, the corporate goals were based 40 percent on the Earnings Target, 37.5 percent on the Unregulated Income Target, 20 percent on the ROIC Target and 2.5 percent on the OGE Energy Resources, Inc. Operational Measures Target. For the remaining executive officers, the corporate goals were based 50 percent on the Earnings Target, 30 percent on the O&M/Capital Target and 20 percent on the Unregulated Income Target.

Establishment of Long-Term Awards

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

For 2006, the Committee made awards of performance units. The number of performance units granted was determined by taking the amount of the executive's long-term award to be delivered in performance units (adjusted on a present value basis), as determined by the Committee, and dividing that amount by the closing price for the Company's Common Stock on February 8, 2006 with a vesting factor applied. This resulted in executive officers receiving performance

units with an expected value at the date of grant of from 30 percent to 150 percent of their 2006 base salaries. The value of the performance units is substantially dependent upon the changing value of the Company's Common Stock in the marketplace. Each executive officer is entitled to receive from 0 percent to 200 percent of the performance units contingently awarded to the executive depending upon corporate performance. At its February 22, 2006 meeting, the Committee determined that for 75 percent of the performance units, this corporate performance will be based on the Company's total shareholder return over a three-year period (defined as share price increase plus dividends paid, divided by share price at beginning of the period) measured against the total shareholder return for such period by a peer group selected by the Committee. For the remaining 25 percent of the performance units, the corporate performance will be based upon the growth in the Company's earnings per share compared to specified targets selected by the Committee.

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

Named Executive	Performance Units
Steven E. Moore	59,288
Peter B. Delaney	31,012
James R. Hatfield	15,967
Steven R. Gerdes	3,724
Danny P. Harris	7,915

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 2005. 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 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 10.33

AMENDMENT NO. 6
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 January 1, 2005, in the following respect:

1. By adding two new sentences at the end of the last paragraph of Section 5 of the Plan as follows:

   "The foregoing provisions of this paragraph, however, shall not apply to any participant who terminates employment with the Company or other Employer after December 31, 2004 but on or prior to December 1, 2005; provided, however, that any bonuses paid after termination of employment shall not be taken into account in applying the provisions of the Plan. Notwithstanding any other provisions of the Plan, in the event any participant terminates employment after December 31, 2004 but on or prior to December 1, 2005, such participant's participation in the Plan shall thereupon terminate with respect to benefits accrued to the date of termination and the benefits accrued to the date of termination that are payable to such participant or his beneficiary or beneficiaries as determined under this Section 5 shall be paid in a lump sum payment pursuant to Section 6 as soon as practicable after termination but in no event later than December 31, 2005."

IN WITNESS WHEREOF, OGE Energy Corp. has caused this instrument to be executed in its name by a member of its Benefits Oversight Committee as of the 8th day of December, 2005.

OGE ENERGY CORP.
By: Its Benefits Oversight Committee

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

Exhibit 12.01

OGE Energy Corp.
SEC Method of Ratio of Earnings to Fixed Charges

	Year Ended Dec 31, 2001	Year Ended Dec 31, 2002	Year Ended Dec 31, 2003	Year Ended Dec 31, 2004	Year Ended Dec 31, 2005
Earnings:					
Pre-tax income from continuing operations	$146,040,434	$121,854,706	$201,237,416	$224,607,903	$237,870,283
Add Fixed Charges	126,275,767	109,743,045	96,489,538	95,978,185	95,956,779
Subtotal	272,316,201	231,597,751	297,726,954	320,586,088	333,827,062
Subtract:					
Allowance for funds used during construction	707,822	905,189	538,624	1,661,732	2,232,715
Total Earnings	271,608,379	230,692,562	297,188,330	318,924,356	331,594,347
Fixed Charges:					
Long-term debt interest expense	111,470,236	99,304,299	87,348,025	83,094,306	79,951,032
Other interest expense	10,549,687	6,628,634	5,488,788	9,359,056	12,570,711
Calculated interest on leased property	4,255,844	3,810,112	3,652,725	3,524,823	3,435,036
Total Fixed Charges	$126,275,767	$109,743,045	$96,489,538	$95,978,185	$95,956,779
Ratio of Earnings to Fixed Charges	2.15	2.10	3.08	3.32	3.46

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 1998 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. 333-104263) pertaining to the dividend reinvestment and stock purchase plan, the Registration Statement (Form S-3 No. 333-104552) pertaining to debt securities, common stock and preferred share purchase rights, the Registration Statement (Form S-3 No. 333-118848) pertaining to debt securities and the Registration Statement (Form S-3 No. 333-127010) pertaining to the dividend reinvestment and stock purchase plan, of our reports dated February 21, 2006, 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, 2005.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 21, 2006

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, 2005; and

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

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

IN WITNESS WHEREOF, the undersigned have hereunto set their hands this 18th day of January, 2006.

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

STATE OF OKLAHOMA)
) SS
COUNTY OF CANADIAN)

On the date indicated above, before me, Shirley Phinney, Notary Public in and for said County and State, personally appeared the above named directors and officers of 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 18th day of January, 2006.

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

My Commission Expires:
March 7, 2006

Exhibit 31.01

CERTIFICATIONS

I, Steven E. Moore, certify that:

1. I have reviewed this annual report on Form 10-K of 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 24, 2006

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

Exhibit 31.01

CERTIFICATIONS

I, James R. Hatfield, certify that:

1. I have reviewed this annual report on Form 10-K of 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 24, 2006

/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, 2005, as filed with the Securities and Exchange Commission (the "Report"), each of the undersigned does hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

February 24, 2006

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

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

Exhibit 99.01

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", "believe", "estimate", "expect", "intend", "objective", "plan", "possible", "potential", "project" and similar expressions are intended to identify forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause the Company's actual results to differ materially from those contemplated in any forward-looking statements include, among others, the following, 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 Oklahoma Department of Environmental Quality 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 14 of Notes to Consolidated Financial Statements of the

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Company's Annual Report on Form 10-K for the year ended December 31, 2005, under the caption Commitments and Contingencies;

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

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

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, natural gas or coal supply costs or availability due to higher demand, shortages, transportation problems or other developments; environmental incidents; or electric transmission or gas pipeline system constraints;

- Ability to negotiate franchise agreements with municipalities and counties in Oklahoma; and

- 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, commodity exposure and nature of competitors entering the industry; and

- 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.