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, 2007

OR

o 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
Rights to Purchase Series A Preferred Stock	New York 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 o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act.
Yes o 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 o

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. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large Accelerated Filer x	Accelerated Filer o
Non-Accelerated Filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

At June 29, 2007, 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 $3,348,527,046 based on the number of shares held by non-affiliates (91,364,994) and the reported closing market price of the common stock on the New York Stock Exchange on such date of $36.65.

At January 31, 2008, 91,812,232 shares of common stock, par value $0.01 per share, were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The Proxy Statement for the Company's 2008 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, 2007

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FORWARD-LOOKING STATEMENTS

Except for the historical statements contained herein, the matters discussed in this Annual Report on Form 10-K, including those matters discussed in “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations,” 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. In addition to the specific risk factors discussed in “Item 1A. Risk Factors” and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations,” factors that could cause actual results to differ materially from the forward-looking statements include, but are not limited to:

- general economic conditions, including the availability of credit, actions of rating agencies and their impact on capital expenditures;
- OGE Energy Corp.’s (collectively, with its subsidiaries, the “Company”) ability and the ability of its subsidiaries to obtain financing on favorable terms;
- prices and availability of electricity, coal, natural gas and natural gas liquids (“NGL”), each on a stand-alone basis and in relation to each other;
- business conditions in the energy and natural gas midstream industries;
- 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 for current and future construction projects;
- federal or state legislation and regulatory decisions (including the approval of future regulatory filings related to the proposed acquisition of the Redbud power plant) 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;
- the discontinuance of regulated accounting principles under Financial Accounting Standards Board Statement of Financial Accounting Standard (“SFAS”) No. 71, “Accounting for the Effects of Certain Types of Regulation”;
- 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;
- the impact of the proposed initial public offering of limited partner interests of OGE Enogex Partners L.P., a Delaware limited partnership (the “Partnership”); and
- other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission (“SEC”) including those listed in Item “1A. Risk Factors” and in Exhibit 99.01 to this Annual Report on Form 10-K.

PART I

Item 1. Business.

THE COMPANY

Introduction

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 four business segments: (i) electric utility, (ii) natural gas transportation and storage, (iii) natural gas gathering and processing and (iv) natural gas marketing. For financial information regarding these segments, see Note 15 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.

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. OG&E 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.

Enogex Inc. and its subsidiaries ("Enogex") are a provider of integrated natural gas midstream services. The vast majority of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located primarily in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex's ongoing operations are organized into two business segments: (1) natural gas transportation and storage and (2) natural gas gathering and processing. Historically, Enogex had also engaged in natural gas marketing through its subsidiary, OGE Energy Resources, Inc. ("OERI"). In connection with the proposed initial public offering of common units of the Partnership discussed below, on January 1, 2008, Enogex distributed the stock of OERI to OGE Energy.

In May 2007, the Company formed the Partnership as part of its strategy to further develop Enogex's natural gas midstream assets and operations. The Partnership has filed a registration statement with the SEC for a proposed initial public offering of its common units, representing limited partner interests in the Partnership (the "Offering"). At the date of this annual report, the registration statement relating to the Offering is not effective. Prior to the closing of the Offering, Enogex Inc., which is currently an Oklahoma corporation, would convert to Enogex LLC, a Delaware limited liability company. In connection with the Offering, the Company is expected to contribute an approximately 25 percent membership interest in Enogex LLC to a wholly owned subsidiary of the Partnership that would serve as Enogex LLC's managing member and would control its assets and operations. A wholly owned subsidiary of the Company will retain the remaining approximately 75 percent membership interest in Enogex LLC. It is currently contemplated that at the completion of the Offering, the Company will indirectly own an approximate 68 percent limited partner interest and a two percent general partner interest in the Partnership.

The completion of the Offering is subject to numerous conditions and no assurances can be made that it will be successfully completed. The Company expects to continue to evaluate strategic alternatives for Enogex, including other transactions that the Company believes could provide long-term value to its shareowners and the proposed initial public offering. The securities offered under the registration statement may not be sold, nor may offers to buy be accepted, prior to the time that the registration statement becomes effective. The information contained in this annual report with respect to the Offering shall not constitute an offer to sell or a solicitation of an offer to buy any securities.

From a financial reporting perspective, the formation of the Partnership had no effect on the Company's financial statements as of and for the periods ended December 31, 2007, 2006 and 2005. In the event that, and beginning with the period in which, the Offering is completed, the Company will consolidate the results of the Partnership with minority interest treatment for the common units of the Partnership owned by unitholders other than the Company or its consolidated subsidiaries.

Company Strategy

The Company's vision is to fulfill its critical role in the nation's electric utility and natural gas midstream pipeline infrastructure and meet individual customers' needs for energy and related services in a safe, reliable and efficient manner. The Company intends to execute its vision by focusing on its regulated electric utility business and unregulated midstream gas business. 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, maintenance of a dividend payout ratio consistent with its peer group and maintenance of strong credit ratings. The Company believes it can accomplish these financial goals by, among other things, pursuing multiple avenues to build its business, maintaining a diversified asset position, continuing to develop a wide range of skills to succeed with changes in its industries, providing products and services to customers efficiently, managing risks effectively and maintaining strong regulatory and legislative relationships.

OG&E has been focused on increased investment at the utility to improve reliability and meet load growth, replace infrastructure equipment, replace aging transmission and distribution systems, provide new products and services and deploy newer technology that improves operational, financial and environmental performance. As part of this plan, OG&E has taken, or has committed to take, the following actions:

- 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;
- OG&E entered into an agreement in February 2006 to engineer, procure and construct a wind generation energy system for a 120 MW wind farm ("Centennial") in northwestern Oklahoma. The wind farm was fully in service in January 2007;
- OG&E announced in early 2007 a six-year construction initiative that is estimated to include up to $2.4 billion in major projects designed to expand capacity, enhance reliability and improve environmental performance. This six-year construction initiative also includes strengthening and expanding the electric transmission, distribution and substation systems and replacing aging infrastructure;
- OG&E announced in October 2007 its goal to increase its wind power generation over the next four years from its current 170 MWs to 770 MWs, and as part of this plan, OG&E expects to issue a request for proposal ("RFP") in the first quarter of 2008;
- OG&E announced in October 2007 its desire to begin building a high-capacity transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma in early to mid-2008 and then eventually to extend the line from Woodward to Guymon, Oklahoma in the Oklahoma Panhandle that would be used by OG&E and others to deliver wind-generated power from western and northwestern Oklahoma to the rest of Oklahoma and other states;
- OG&E has also previously committed to the Southwest Power Pool ("SPP") to build the Oklahoma portion of the western half of the SPP "X-Plan" that includes transmission lines from Woodward to Tuco, Texas and from Woodward to Spearville, Kansas;
- OG&E entered into agreements in January 2008 to purchase a 51 percent ownership interest in the 1,230 MW Redbud power plant; and
- With the previously announced six-year construction initiative discussed above, and including the acquisition of the Redbud power plant, OG&E's 2008 to 2013 capital expenditures are expected to be approximately $3.0 billion.

The increase in wind power generation, the building of the transmission lines and the acquisition of the Redbud power plant are all subject to numerous regulatory and other approvals, including appropriate regulatory treatment from the OCC and, in the case of the transmission lines, the SPP. Other projects involve installing new emission-control and monitoring equipment at existing OG&E power plants to help meet OG&E's commitment to comply with current and future environmental requirements. For additional information regarding the above items and other regulatory matters, see Note 17 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, capturing growth opportunities through expansion projects and increased utilization of existing assets and strategic acquisitions. 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. Over the past several years, Enogex has initiated multiple organic growth projects. Currently, Enogex's organic growth capital expenditures are focused on three primary areas:

- upgrades to Enogex's existing transportation system due to increased volumes as a result of the broader shift of gas flow from the Rocky Mountains and the mid-continent to markets in the northeast and southeast United States;
- expansions on the east side of Enogex's gathering system, primarily in the Woodford Shale play in southeastern Oklahoma through construction of new facilities and expansion of existing facilities and its interest in the joint venture, Atoka Midstream LLC; and
- expansions on the west side of Enogex's gathering system, primarily in the Granite Wash play and Atoka play in the Wheeler County, Texas area, which is located in the Texas Panhandle.

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 2007, five other communities and two rural electric cooperatives in Oklahoma and western Arkansas purchased electricity from OG&E for resale. The service area 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, 2007 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 2007 was approximately 6,317 MWs on August 14, 2007. OG&E's load responsibility peak demand was approximately 6,031 MWs on August 14, 2007. As reflected in the table below and in the operating statistics that follow, there were approximately 26.4 million megawatt-hour ("MWH") sales to OG&E's customers ("system sales") in both 2007 and 2006 and 26.0 million MWH system sales in 2005. Variations in system sales for the three years are reflected in the following table:

Year ended December 31 *(In millions)*	**2007**	**2007 vs. 2006 Increase**	2006	2006 vs. 2005 Increase	2005	2005 vs. 2004 Increase
System Sales (A)	**26.4**	**---%**	26.4	1.5%	26.0	5.3%

(A) Sales are in millions of MWHs.

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

Besides competition from other suppliers or marketers of electricity, OG&E competes with suppliers of other forms of energy. The degree of competition between suppliers may vary depending on relative costs and supplies of other forms of energy. See Note 17 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)*	**2007**	2006	2005
ELECTRIC ENERGY *(Millions of MWH)*			
Generation (exclusive of station use)	**23.8**	24.6	24.8
Purchased	**5.2**	3.9	3.3
Total generated and purchased	**29.0**	28.5	28.1
Company use, free service and losses	**(1.9)**	(2.1)	(2.0)
Electric energy sold	**27.1**	26.4	26.1
ELECTRIC ENERGY SOLD *(Millions of MWH)*			
Residential	**8.7**	8.7	8.5
Commercial	**6.3**	6.2	6.0
Industrial	**4.2**	4.4	4.5
Oilfield	**2.8**	2.7	2.6
Street light	**0.1**	0.1	0.1
Public authorities	**2.9**	2.8	2.8
Sales for resale	**1.4**	1.5	1.5
System sales	**26.4**	26.4	26.0
Off-system sales	**0.7**	---	0.1
Total sales	**27.1**	26.4	26.1
ELECTRIC OPERATING REVENUES *(In millions)*			
Residential	**$ 706.4**	$ 698.8	$ 663.6
Commercial	**450.1**	428.3	418.9
Industrial	**221.4**	215.7	220.8
Oilfield	**140.9**	129.3	134.8
Street light	**9.1**	11.4	12.2
Public authorities	**172.3**	159.6	160.9
Sales for resale	**68.8**	65.4	67.7
Provision for rate refund	**0.1**	(0.9)	(2.0)
System sales revenues	**1,769.1**	1,707.6	1,676.9
Off-system sales revenues	**35.1**	2.7	4.9
Other	**30.9**	35.4	38.9
Total Electric Operating Revenues	**$ 1,835.1**	$ 1,745.7	$ 1,720.7
ACTUAL NUMBER OF ELECTRIC CUSTOMERS *(At end of period)*			
Residential	**653,369**	647,548	639,733
Commercial	**83,901**	82,974	81,728
Industrial	**3,142**	3,181	3,207
Oilfield	**6,324**	6,324	6,265
Street light	**250**	250	250
Public authorities	**15,196**	14,519	14,265
Sales for resale	**52**	44	45
Total	**762,234**	754,840	745,493
AVERAGE RESIDENTIAL CUSTOMER SALES			
Average annual revenue	**$ 1,086.03**	$ 1,084.31	$ 1,043.60
Average annual use (kilowatt-hour (“KWH”))	**13,325**	13,526	13,455
Average price per KWH (cents)	**$ 8.15**	$ 8.02	$ 7.76

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, 2007, 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 the FERC jurisdictional rates.

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 other states in their 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 17 of Notes to Consolidated Financial Statements.

Recent Regulatory Matters

Cancelled Red Rock Power Plant. On October 11, 2007, the OCC issued an order denying OG&E and Public Service Company of Oklahoma's ("PSO") request for pre-approval of their proposed 950 MW Red Rock power plant project. The plant, which was to be built at OG&E's Sooner plant site, was to be 42 percent owned by OG&E, 50 percent owned by PSO and eight percent owned by the Oklahoma Municipal Power Authority ("OMPA"). As a result, on October 11, 2007, OG&E, PSO and the OMPA agreed to terminate agreements to build and operate the plant. At December 31, 2007, OG&E had incurred approximately $17.5 million of capitalized costs associated with the Red Rock power plant project. In December 2007, OG&E filed an application with the OCC requesting authorization to defer, and establish a method for recovery of, approximately $14.7 million of Oklahoma jurisdictional costs associated with the Red Rock power plant project that are currently reflected in Deferred Charges and Other Assets on the Company's Consolidated Balance Sheets. If the request for deferral is not approved, the deferred costs will be expensed. In February 2008, the OCC issued a procedural schedule with a hearing scheduled for May 7, 2008. OG&E expects to receive an order from the OCC in this matter by the end of 2008.

OCC Order Confirming Savings / Acquisition of McClain Power Plant. The 2002 agreed-upon settlement of an OG&E rate case ("2002 Settlement Agreement") required that, if OG&E did not acquire electric generation of not less than 400 MW ("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. On July 9, 2004, OG&E completed the acquisition of the McClain Plant that was intended to satisfy the requirement in the 2002 Settlement Agreement to acquire New Generation. On June 7, 2007, OG&E filed an application with the OCC supporting its compliance with the 2002 Settlement Agreement. On November 21, 2007, OG&E received an order from the OCC affirming that the acquisition of the McClain Plant provided savings to OG&E's Oklahoma customers in excess of the required $75 million over the three-year period from January 1, 2004 through December 31, 2006.

See Note 17 of Notes to Consolidated Financial Statements for a discussion of certain regulatory matters including, among other things, security enhancements, review of OG&E's fuel adjustment clause, cogeneration credit rider, OG&E FERC audit, national energy legislation and state legislative initiatives.

Regulatory Assets and Liabilities

OG&E, as a regulated utility, is subject to the accounting principles prescribed by SFAS No. 71. 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, 2007 and 2006, OG&E had regulatory assets of approximately $330.7 million and $319.2 million, respectively, and regulatory liabilities of approximately $148.2 million and $224.5 million, respectively. See Note 1 of Notes to Consolidated Financial Statements for a further discussion.

As discussed in Note 17 of Notes to Consolidated Financial Statements, legislation was enacted in the 1990's for Oklahoma that was to restructure the electric utility industry in that state. The 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 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.

Rate Structures

Oklahoma

OG&E's standard tariff rates include a cost-of-service component (including an authorized return on capital) plus an automatic fuel adjustment clause mechanism that allows OG&E to pass through to customers variances (either positive or negative) in the actual cost of fuel as compared to the fuel component in OG&E's most recently approved rate case.

OG&E offers several alternate 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 rate case completed in December 2005. 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. OG&E's ownership and access to wind resources makes the renewable wind power option a possible choice in meeting the renewable energy needs of our conservation-minded customers and provides the customers with a means to reduce their exposure to increased prices for natural gas used by OG&E as boiler fuel. 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 usage 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 choices, 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 not determinable in future years because customers may choose to remain on existing rate options instead of volunteering for the alternative rate option choices. There was no overall material impact in 2006 associated with these rate options; however, there was an increase in other income from the GFB option in 2007. Revenue variations may occur in the future based upon changes in customers' usage characteristics if they choose alternative rate options.

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 that allows customers to pay fuel costs that better reflect operational energy losses related to a specific service level. The OCC order also approved a military base rider that demonstrates Oklahoma's continued commitment to our military partners.

Arkansas

During 2006, energy efficiency hearings were held by the APSC for all Arkansas utilities. These hearings led to new rules being approved for all Arkansas utilities in January 2007. OG&E filed for seven new energy efficiency programs that were accepted and approved by the APSC in September 2007. Six of the seven programs were implemented in October 2007 and have attracted new customers, which management believes has resulted in an improved use of energy resources throughout OG&E's Arkansas jurisdiction. The revised compact fluorescent lamp and energy efficiency program is expected to be submitted in March 2008 seeking approval for immediate implementation in 2008.

Fuel Supply and Generation

During 2007, approximately 62 percent of the OG&E-generated energy was produced by coal-fired units, 36 percent by natural gas-fired units and two percent by wind-powered units. Of OG&E's 6,229 total MW capability reflected in the table under Item 2. Properties, approximately 3,514 MWs, or 56 percent, are from natural gas generation, approximately 2,595 MWs, or 42 percent, are from coal generation and approximately 120 MWs, or two percent, are from wind 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 and/or wind 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:

Year ended December 31	**2007**	2006	2005	2004	2003
Coal	**$ 1.10**	$ 1.10	$ 0.98	$ 1.00	$ 0.93
Natural Gas	**$ 6.77**	$ 7.10	$ 8.76	$ 6.57	$ 6.46
Weighted Average	**$ 3.13**	$ 2.98	$ 3.21	$ 2.69	$ 2.27

The increase in the weighted average cost of fuel in 2007 as compared to 2006 was primarily due to increased natural gas volumes. The decrease in the weighted average cost of fuel in 2006 as compared to 2005 was primarily due to decreased natural gas prices partially offset by increased amounts of natural gas being burned. 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. 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 automatic fuel adjustment clauses that are approved by the OCC and the APSC.

Coal

All of OG&E's coal-fired units, with an aggregate capability of approximately 2,595 MWs, are designed to burn low sulfur western coal. OG&E purchases coal primarily under contracts expiring in years 2010 and 2011. During 2007, OG&E purchased approximately 9.6 million tons of coal from various Wyoming suppliers. The combination of all coal has a weighted average sulfur content of 0.3 percent and can be burned in these units under existing federal, state and local environmental standards (maximum of 1.20 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 0.51 lbs. of sulfur dioxide per MMBtu, well within the limitations of the current provisions of the Federal Clean Air Act discussed in Note 16 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 16 of Notes to Consolidated Financial Statements for a discussion of environmental matters which may affect OG&E in the future.

Coal Shipment Disruption

In mid-2005, OG&E experienced a coal shipment disruption due to successive derailments on the jointly-owned rail line serving the Southern Powder River Basin coal producers. As a result, OG&E's level of coal inventory significantly decreased. In late 2005, the rail lines were repaired and returned to normal operating conditions. At December 31, 2007, OG&E had slightly more than 57 days of coal supply for each of its coal-fired units at its Sooner and Muskogee generating plants. Furthermore, if no other significant disruptions occur going forward, OG&E expects to maintain its coal inventory level at approximately 60 days.

Natural Gas

In August 2007, OG&E issued an RFP for gas supply purchases for periods from November 2007 through March 2008, which accounted for approximately 15 percent of its projected 2008 natural gas requirements. The contracts resulting from this RFP are tied to various gas price market indices and will expire in 2008. Additional gas supplies to fulfill OG&E's remaining 2008 natural gas requirements will be acquired through additional RFPs in early to mid-2008, along with monthly and daily purchases, all of which are expected to be made at competitive market prices.

In 1993, OG&E began utilizing a natural gas storage facility for storage services that allowed OG&E to maximize the value of its generation assets. Storage services are now provided by Enogex as part of Enogex's gas transportation and storage contract with OG&E. At December 31, 2007, OG&E had approximately 2.0 million MMBtu's in natural gas storage that it acquired for approximately $8.6 million.

Purchased Power

In March 2007, OG&E issued an RFP for capacity and/or firm energy purchases for the summer periods of 2008, 2009, and/or 2010. In November 2007, OG&E signed a purchase contract with Redbud for purchases in the summer periods of 2008 and 2009. OG&E submitted notice of the contract to the OCC on January 2 and 3, 2008. Interventions and protests were due within 15 days of submission of the notice. No interventions or protests were received in this matter and OG&E considers this purchase contract to be final. The purchase contract will be terminated if the acquisition of Redbud by OG&E, the OMPA and the GRDA is completed as discussed in Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Wind

In January 2007, OG&E's 120 MW Centennial wind farm was fully in service. The OCC authorized a recovery rider for up to $205 million in construction costs and allowance for funds used during construction. As indicated in the settlement agreement with the OCC related to OG&E's Centennial wind farm, OG&E must file for a general rate review that will permit the OCC to issue an order no later than December 31, 2009. Also, during 2003, OG&E entered into a 15-year contract with FPL Energy whereby OG&E has access to up to 50 MWs of electricity generated at a wind farm near Woodward, Oklahoma.

On October 30, 2007, OG&E announced its goal to increase its wind power generation over the next four years from its current 170 MWs to 770 MWs, and as part of this plan, OG&E expects to issue an RFP in the first quarter of 2008. OG&E also announced its desire to begin building a transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma in early to mid-2008 and then eventually to extend the line from Woodward to Guymon, Oklahoma in the Oklahoma Panhandle. This high-capacity transmission line would be used by OG&E and others to deliver wind-generated power from western and northwestern Oklahoma to the rest of Oklahoma and other states. The increase in wind power generation would be subject to numerous regulatory and other approvals, including proposed regulatory treatment from the OCC.

Safety and Health Regulation

OG&E is subject to a number of federal and state laws and regulations, including the federal Occupational Safety and Health Act of 1970 ("OSHA") and comparable state statutes, whose purpose is to protect the safety and health of workers. In addition, the OSHA hazard communication standard, the U.S. Environmental Protection Agency ("EPA") community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in OG&E's operations and that this information be provided to employees, state and local government authorities and citizens. The Company believes that OG&E is in material compliance with all applicable laws and regulations relating to worker safety and health.

NATURAL GAS PIPELINE OPERATIONS - ENOGEX

Overview

Enogex is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting and storing natural gas. The vast majority of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located primarily in the Arkoma and Anadarko basins of Oklahoma and the

Texas Panhandle. Enogex's ongoing operations are organized into two business segments: (1) natural gas transportation and storage and (2) natural gas gathering and processing.

Historically, Enogex had also engaged in natural gas marketing through its subsidiary, OERI. In connection with the proposed Offering of the Partnership, on January 1, 2008, Enogex distributed the stock of OERI to OGE Energy.

Transportation and Storage

General

Enogex's transportation and storage business owns and operates approximately 2,318 miles of intrastate natural gas transportation pipelines with approximately 1.52 trillion British thermal units per day ("TBtu/d") of average daily throughput during 2007. Enogex also owns and operates two storage facilities currently being operated at a working gas level of approximately 23 billion cubic feet ("Bcf"). Enogex provides fee-based intrastate transportation services on a firm and interruptible basis and, pursuant to Section 311 of the Natural Gas Policy Act ("NGPA"), provides interstate transportation services on an interruptible basis. Enogex's obligation to provide firm transportation service means that it is obligated to transport natural gas nominated by the shipper up to the maximum daily quantity specified in the contract. In exchange for that obligation on Enogex's part, the shipper pays a specified demand or reservation charge, whether or not it utilizes the capacity. In most cases, the shipper also pays a transportation or commodity charge with respect to quantities actually transported by Enogex. Enogex's obligation to provide interruptible transportation service means that it is only obligated to transport natural gas nominated by the shipper to the extent that it has available capacity. For this service, the shipper pays no demand or reservation charge but pays a transportation or commodity charge for quantities actually shipped. Enogex derives a substantial portion of its transportation revenues from firm transportation services. To the extent pipeline capacity is not needed for such firm intrastate transportation service, Enogex offers interruptible interstate transportation services pursuant to Section 311 of the NGPA as well as interruptible intrastate transportation services.

Enogex delivers natural gas to most interstate and intrastate pipelines and end-users connected to its systems from the Arkoma and Anadarko basins (including recent growth activity in the Granite Wash play in western Oklahoma and the Texas Panhandle and the Woodford Shale play in southeastern Oklahoma). At December 31, 2007, Enogex was connected to 11 third-party natural gas pipelines at 64 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 and Ozark Gas Transmission, L.L.C. Further, Enogex is connected to 27 end-user customers, including 15 natural gas-fired electric generation facilities in Oklahoma.

Enogex owns and operates two natural gas 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 Bcf and have approximately 650 million cubic feet per day ("MMcf/d") of maximum withdrawal capability and approximately 650 MMcf/d of injection capability. Enogex offers both fee-based firm and interruptible storage services to third parties. Services offered under Section 311 of the NGPA are pursuant to terms and conditions specified in Enogex's Statement of Operating Conditions ("SOC") for gas storage and at market-based rates negotiated with each customer. Enogex's storage facilities are also used to support its no-notice load following transportation and storage contract with OG&E.

Enogex uses its storage assets to meet its contractual obligations under certain load following transportation contracts. Enogex also periodically conducts an open season to solicit commitments for contracted capacity and deliverability to third parties for contracts that generally do not exceed three years.

Customers and Contracts

Enogex's major transportation customers are OG&E and PSO, the second largest electric utility in Oklahoma. Enogex provides gas transmission delivery services to all of PSO's natural gas-fired electric generation facilities in Oklahoma under a firm intrastate transportation contract. The PSO contract, which expires January 1, 2013, unless extended, and the OG&E contract, which expires April 30, 2009, unless extended, provide for a monthly demand charge plus variable transportation charges (including fuel). As part of the no-notice load following contract with OG&E, Enogex provides natural gas storage services for OG&E. Enogex has been providing natural gas storage services to OG&E since August 2002 when it acquired the Stuart Storage Facility. Demand for natural gas on Enogex's system is usually greater during the summer, primarily due to demand by gas-fired electric generation facilities to serve residential and commercial electricity requirements. Natural gas produced in excess of that which is used during the winter months is typically stored to meet the increased demand for natural gas during the summer months. During 2005, 2006 and 2007, revenues from Enogex's firm intrastate transportation and storage contracts were approximately $95.0 million, $98.1 million and $103.9 million, respectively, of which approximately $47.6 million, $47.6 million and $47.4 million, respectively, was attributed to OG&E and $13.3 million, $13.3 million and $13.3 million, respectively, was attributed to PSO. Revenues from Enogex's firm intrastate transportation and storage contracts represented approximately 38 percent of Enogex's consolidated gross margin in 2005, 31 percent in 2006 and 29 percent in 2007.

Competition

Enogex's transportation and storage assets compete with numerous interstate and intrastate pipelines, including several of the interconnected pipelines discussed above, 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-fired electric generation facilities contribute their highest value when they have the capability to provide load following service to the customer (*i.e*., the ability of the generation facility to regulate generation to respond to and meet the instantaneous changes in customer demand for electricity). While the physical characteristics of natural gas-fired electric generation facilities are known to provide quick start-up, on-line functionality and the ability to efficiently provide varying levels of electric generation relative to other forms of generation, a key part of their effectiveness is contingent upon having access to an integrated pipeline and storage system that can respond quickly to meet their corresponding fluctuating fuel needs. We believe that Enogex is well positioned to compete for the needs of these generators due to the ability of its transportation and storage assets to provide no-notice load following 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 Enogex's system.

Regulation

The transportation rates charged by Enogex for transporting natural gas in interstate commerce 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. The rate review may, but will not necessarily, involve an administrative-type hearing before the FERC Staff panel and an administrative appellate review. In the past, Enogex has successfully settled, rather than litigated, its Section 311 rate cases. Offering interruptible Section 311 transportation gives Enogex the opportunity to utilize any unused capacity on an interruptible basis in interstate commerce and thus increase its transportation revenues without increasing its regulatory burden appreciably. Enogex currently has two zones under its Section 311 rate structure - an East Zone and a West Zone with a maximum transportation rate and a fuel retention rate for each zone. Enogex may charge up to its maximum established zonal East and West transportation rates for transportation in one zone or cumulative maximum rates for transportation in both zones and the applicable fixed zonal fuel percentage(s) for the fuel used in shipping natural gas under Section 311 on the Enogex system.

The fixed zonal fuel percentages are adjusted annually and remain in effect for a calendar year. The mechanism used to establish the percentages is a fuel tracker filed annually at the FERC to establish prospectively the zonal fixed fuel factors (expressed as a percentage of natural gas shipped in the zone) for the upcoming calendar year. Fuel usage is later trued-up to actual usage over a two-year period based on the value of the gas at the time of usage.

On October 1, 2007, Enogex made its required triennial rate filing at the FERC to update its Section 311 maximum interruptible transportation rates for service in the East Zone and West Zone. Enogex's filing requested an increase in the maximum zonal rates and proposed to place such rates into effect on January 1, 2008. A number of parties intervened and some additionally filed protests. In the normal course of the triennial rate case, the FERC Staff and intervenors serve data requests on Enogex with respect to the cost of service submitted with the filing in support of the proposed rates and the parties, thereafter, undertake settlement discussions. There is no statutory deadline by which the FERC must act on the filing. The regulations provide that the FERC has 150 days to act on the filing but also permit the FERC to issue an order extending the time period for action, as the FERC has done in past Enogex cases. The FERC Staff has served its initial data requests on Enogex and Enogex has submitted its responses. The parties are currently in settlement negotiations. The FERC Staff, Enogex and one intervenor have exchanged offers of settlement, but a settlement has not been reached. Enogex has not, as of yet, placed the increased rates into effect. Enogex must file its next rate case no later than October 1, 2010 to comply with the FERC's requirement for triennial filings.

On November 15, 2007, Enogex made its annual filing to establish fixed fuel percentages for its East Zone and West Zone, respectively, for calendar year 2008 ("2008 Fuel Year"). There were no protests and the FERC accepted the proposed zonal fuel percentages for 2008 Fuel Year by order of December 19, 2007.

On May 29, 2007, the FERC notified Enogex that it was commencing an audit to determine whether and how Enogex is complying with periodic regulatory reporting requirements for intrastate pipelines. On the same day, the FERC notified a number of other intrastate pipelines and storage entities of comparable audits. In preparing for the audit, Enogex advised the FERC Staff that it had inadvertently failed to timely file three storage reports required under FERC regulations. Enogex promptly submitted those storage reports to the FERC. The FERC completed its audit of Enogex in September 2007 and approved the corrective actions taken by Enogex and determined that no further corrective action is required.

Enogex received FERC approval to unbundle its remaining gathering assets and services from its transportation services and completed such unbundling, effective October 1, 2005. As a result, FERC regulates Enogex's Section 311 transportation services but does not regulate its gathering services. In addition, the FERC does not regulate Enogex's intrastate transportation services because these services are not Section 311 services. These services include those intrastate transportation services provided to the gas-fired electric generation facilities and other end users within Oklahoma. As such the rates charged by Enogex for transporting natural gas for the Oklahoma utility companies, independent electric generation facilities and other shippers within Oklahoma are not subject to FERC regulation. Nor are the rates charged by Enogex for any intrastate transportation service subject to direct state regulation by the OCC. However, 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.

Enogex's pipeline operations are subject to various state and federal safety and environmental and pipeline transportation laws. For example, the U.S. Department of Transportation has adopted regulations requiring pipeline operators to develop integrity management programs for its transportation pipelines. During 2007, Enogex incurred approximately $11.7 million of capital expenditures and operating costs to implement its pipeline integrity management program along certain segments of its natural gas pipelines. Enogex currently estimates that it will incur capital expenditures and operating costs of approximately $31.9 million between 2008 and 2011 in connection with its pipeline integrity management program. The estimated capital expenditures and operating costs include Enogex's estimates for the assessment, remediation and prevention or other mitigation that may be determined to be necessary as a result of the integrity management program. At this time, Enogex cannot predict the ultimate costs of compliance with this regulation because those costs will depend on the number and extent of any repairs found to be necessary as a result of the pipeline integrity assessment that is required by the rule. Enogex will continue its pipeline integrity program to assess, remediate and maintain the integrity of its pipelines. The results of these activities could cause Enogex to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operations of its pipelines.

Recent System Expansions

Over the past several years, Enogex has initiated multiple organic growth projects. Currently, in Enogex's transportation and storage business, organic growth capital expenditures are focused on upgrades to Enogex's existing transportation system due to increased volumes as a result of the broader shift of gas flow from the Rocky Mountains and the mid-continent to markets in the northeast and southeast United States.

In December 2006, Enogex entered into a firm capacity lease agreement with Midcontinent Express Pipeline, LLC ("MEP") for a primary term of 10 years (subject to possible extension) that would give MEP and its shippers access to capacity on Enogex's system. The quantity of capacity subject to the MEP lease agreement is currently 275 MMcf/d, with the quantity ultimately to be leased subject to being increased by mutual agreement pursuant to the lease agreement. In addition to MEP's lease of Enogex's capacity, the proposed MEP project includes construction by MEP of a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. Pending necessary regulatory approval, the MEP project is currently expected to be in service during the first quarter of 2009. Enogex currently estimates that its capital expenditures related to this project will be approximately $86 million. The lease agreement with MEP is subject to certain contingencies, including regulatory approval. Prior to that approval, Enogex may incur expenditures of between approximately $20 million and $40 million primarily related to commitments for materials that can be sold or used in normal operations in the event the MEP project does not proceed. The amount not recovered or utilized for such expenditures is not expected to be material.

MEP filed an application with the FERC on October 9, 2007 requesting a certificate of public convenience and necessity authorizing MEP to construct its pipeline and lease certain capacity from Enogex. On October 9, 2007, Enogex also filed an application with the FERC for issuance of a limited jurisdiction certificate authorizing its lease agreement with MEP. Certain Enogex shippers have filed motions to intervene in Enogex's FERC certificate proceeding, and some have protested Enogex's certificate application. Protestors have claimed that it is unduly discriminatory for Enogex to propose to lease capacity to MEP while not generally offering firm interstate transportation service, that the lease arrangement will adversely affect the availability of interruptible interstate transportation service on the Enogex system and that the lease payment specified under the MEP lease agreement is unduly preferential in MEP's favor. These protestors have urged the FERC to reject the MEP lease arrangement or to condition its acceptance on a requirement that Enogex offer existing shippers taking interruptible interstate service the opportunity to convert that service to firm service. One protestor has asked the FERC to consolidate the Enogex certificate proceeding with Enogex's Section 311 triennial rate proceeding currently pending before the FERC. While Enogex cannot predict what action the FERC may take regarding the lease agreement, Enogex believes that the proposed MEP lease arrangement is consistent with FERC policy and precedent involving similar lease arrangements.

On January 18, 2008, Enogex filed a 30-day advance notice to advise the FERC of its intended construction of the Bennington Station Facilities. In that notice, Enogex described the environmental impacts likely to be associated with construction and operation of a new 24,000 horsepower transmission compressor station and associated pipeline that Enogex proposes to construct to support its provision of pipeline capacity under its capacity leases including the lease with MEP. Enogex believes that it has complied with all applicable requirements of the FERC's regulations pertaining to an intrastate pipeline's construction of facilities under Section 311 of the NGPA. The FERC did not take any action with respect to Enogex's advance notice filing and Enogex has begun construction of the Bennington Station Facilities.

Gathering and Processing

General

Enogex provides well connect, gathering, measurement, treating, dehydration, compression and processing services for various types of producing wells owned by various sized producers who are active in the areas in which Enogex operates. Most natural gas produced at the wellhead contains NGLs. Natural gas produced in association with crude oil typically contains higher concentrations of NGLs than natural gas produced from gas wells. This high-content, or "rich," natural gas is generally not acceptable for transportation in the nation's transmission pipeline system or for commercial use. The streams of processable natural gas gathered from wells and other sources are gathered into Enogex's gas gathering systems and are delivered to processing plants for the extraction of NGLs, leaving residual dry gas that meets transmission pipeline and commercial quality specifications. Furthermore, the processing plants produce marketable NGLs.

Enogex's gathering system includes approximately 5,534 miles of natural gas gathering pipelines with approximately 1.05 TBtu/d of average daily throughput during 2007 extending from southwestern Oklahoma to the eastern Texas Panhandle. During 2007, Enogex connected 374 new producing wells (including 196 wells behind central receipt points), located in the Arkoma and Anadarko basins (including recent growth activity in the Granite Wash play in western Oklahoma and the Texas Panhandle and the Woodford Shale play in southeastern Oklahoma) to its gathering systems. At December 31, 2007, Enogex's gathering system was connected to approximately 3,100 wells and approximately 250 central receipt points, all of which are equipped with state-of-the-art electronic flow measurement technology. Approximately 70 percent of Enogex's gathered volumes are received at wellheads while 30 percent is gathered from central receipt or other interconnection points.

Enogex owns and operates six natural gas processing plants with a total inlet capacity of approximately 723 MMcf/d and has a 50 percent interest in and operates an additional natural gas processing plant with an inlet capacity of approximately 20 MMcf/d, all in Oklahoma. Where the quality of natural gas received dictates the removal of NGLs, such gas is aggregated through the gathering system to the inlet of one or more of the seven processing plants operated by Enogex. The resulting processed stream of natural gas is then delivered from the tailgate of each plant into Enogex's intrastate natural gas transportation system. For the year ended December 31, 2007, Enogex extracted and sold approximately 385 million gallons of NGLs.

In 2007 and 2008, Enogex has pursued and expects to pursue several projects to address tightening processing capacity as a result of increasing supply:

- In July 2007, Enogex completed a restaging of a compression turbine at the Thomas plant, which should allow realization of an additional 20 MMBtu/d of capacity at that plant. Enogex expects the construction of a new pipeline between its large-diameter "super-header" gathering system and the Canute processing plant will permit it to move excess gas available for processing on the "super-header" gathering system to the Canute processing plant (which is operating at under capacity). In addition, Enogex is reviewing options for moving excess gas available for processing at the Wetumka processing plant to the Harrah processing plant (which is operating at under capacity). As a result, Enogex expects that it will be able to increase the utilization of its existing plants.

- Enogex also intends to build or acquire additional processing capacity as the need arises. In particular, in August 2007, Enogex completed a new processing plant as part of its Atoka Midstream LLC joint venture in the Woodford Shale play in southeastern Oklahoma, which has added 20 MMBtu/d of capacity. Enogex is also constructing a new

100 MMcf/d refrigeration dewpoint conditioning plant in Roger Mills County of Oklahoma. This plant is expected to be operational in the second quarter of 2008. In addition, Enogex plans to build a new 120 MMcf/d cryogenic plant equipped with electric compression near Clinton, Oklahoma. This plant will process new gas developing in the area and is expected to be in service in early 2009.

- Enogex may relocate its currently idle Red Fork and Davenport processing plants, which Enogex believes could add up to 48 MMBtu/d of additional gas processing capacity to its system.

Enogex's gathering and processing business has approximately 225,000 horsepower of owned compression. Enogex also has its own compression overhaul center and specialized compression workforce.

Enogex gathers and processes natural gas pursuant to a variety of arrangements generally categorized as "fee-based" arrangements, "percent-of-proceeds" and "percent-of-liquids" arrangements and "keep-whole" arrangements. Under fee-based arrangements, Enogex earns cash fees for the services that it renders. Under the latter types of arrangements, Enogex generally purchases raw natural gas and sells processed natural gas and NGLs or receives NGLs. Percent-of-proceeds, percent-of-liquids and keep-whole arrangements involve commodity price risk to Enogex because Enogex's margin is based in part on natural gas and NGL prices. Enogex seeks to minimize its exposure to fluctuations in commodity prices in several ways, including managing its contract portfolio. In managing its contract portfolio, Enogex classifies its gathering and processing contracts according to the nature of commodity risk implicit in the settlement structure of those contracts.

- *Fee-Based Arrangements*. Under these arrangements, Enogex generally is paid a fixed cash fee for performing the gathering and processing service. This fee is directly related to the volume of natural gas that flows through Enogex's system and is not directly dependent on commodity prices. A sustained decline, however, in commodity prices could result in a decline in volumes and, thus, a decrease in Enogex's fee revenues. These arrangements provide stable cash flows, but minimal, if any, upside in higher commodity price environments. At December 31, 2007, these arrangements accounted for approximately seven percent of Enogex's natural gas processed volumes.
- *Percent-of-Proceeds and Percent-of-Liquids Arrangements*. Under these arrangements, Enogex generally gathers raw natural gas from producers at the wellhead, transports the gas through its gathering system, processes the gas and sells the processed gas and/or NGLs at prices based on published index prices. These arrangements provide upside in high commodity price environments, but result in lower margins in low commodity price environments. The price paid to producers is based on an agreed percentage of the proceeds of the sale of processed natural gas, NGLs or both or the expected proceeds based on an index price. We refer to contracts in which Enogex shares in specified percentages of the proceeds from the sale of natural gas and NGLs as percent-of-proceeds arrangements and in which Enogex receives proceeds from the sale of NGLs or the NGLs themselves as compensation for its processing services as percent-of-liquids arrangements. Under percent-of-proceeds arrangements, Enogex's margin correlates directly with the prices of natural gas and NGLs. Under percent-of-liquids arrangements, Enogex's margin correlates directly with the prices of NGLs (although there is often a fee-based component to both of these forms of contracts in addition to the commodity sensitive component). At December 31, 2007, these arrangements accounted for approximately 25 percent of Enogex's natural gas processed volumes.
- *Keep-Whole Arrangements*. Under these arrangements, Enogex processes raw natural gas to extract NGLs and pays to the producer the full gas equivalent British thermal unit ("Btu") value of raw natural gas received from the producer in the form of either processed gas or its cash equivalent. Enogex is generally entitled to retain the processed NGLs and to sell them for its own account. Accordingly, Enogex's margin is a function of the difference between the value of the NGLs produced and the cost of the processed gas used to replace the thermal equivalent of those NGLs. The profitability of these arrangements is subject not only to the commodity price risk of natural gas and NGLs but also to the price of natural gas relative to NGL prices. These arrangements can provide large profit margins in favorable commodity price environments, but also can be subject to losses if the cost of natural gas exceeds the value of its thermal equivalent of NGLs. Many of Enogex's keep-whole contracts include provisions that reduce its commodity price exposure, including (1) conditioning floors (such as the default processing fee described below) that require the keep-whole contract to convert to a fee-based arrangement if the NGLs have a lower value than their gas equivalent Btu value in natural gas, (2) embedded discounts to the applicable natural gas index price under which Enogex may reimburse the producer an amount in cash for the gas equivalent Btu value of raw natural gas acquired from the producer, or (3) fixed cash fees for ancillary services, such as gathering, treating and compressing. At December 31, 2007, these arrangements accounted for approximately 68 percent of Enogex's natural gas processed volumes.

In addition, as a seller of NGLs, Enogex is exposed to commodity price risk associated with downward movements in NGL prices. NGL prices have experienced volatility in recent years in response to changes in the supply and demand for NGLs and market uncertainty. In response to this volatility, in 2002, Enogex revised its SOC used as part of its typical natural gas processing arrangements and included language that requires a "default processing fee" in the event the gathered gas exceeds downstream interconnect specifications. Natural gas that is greater than 1,080 Btu per cubic foot coming out of wells must typically be processed before it can enter an interstate pipeline. The default processing fee stipulates a minimum fee to be paid to the processor if the market for NGLs is lower than the gas equivalent Btu value of the natural gas that is removed from the stream. The default processing fee helps to minimize the risk of processing gas that is greater than 1,080 Btu per cubic foot when the price of the NGLs to be extracted and sold is less than the Btu value of the natural gas that Enogex otherwise would be required to replace.

Enogex is active in the extraction and marketing of NGLs from natural gas. The liquids extracted include condensate liquids, 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.

Approximately 16 percent of the commercial grade propane produced at Enogex's plants is sold on the local market. The balance of propane and the other NGLs produced by Enogex is 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 Enogex's plants except the Calumet plant, is also sold under contract or on the spot market.

Enogex's large diameter, rich gas gathering pipelines in western Oklahoma are configured such that natural gas from the Wheeler County area in the Texas Panhandle can flow to the Cox City, Thomas or Calumet gas processing plants. These large-diameter "super-header" gathering systems of Enogex provide gas routing flexibility for Enogex to optimize the economics of its gas processing and to improve system utilization and reliability.

Several of Enogex's processing plants are currently operating at or near full capacity, such as the Cox City processing plant. As Enogex experiences increased growth in regions such as the Woodford Shale play, Enogex will evaluate the need to expand its processing plants in order to meet the growing needs of its producer customers.

Natural Gas Supply

As of December 31, 2007, approximately 3,100 wells and approximately 250 central receipt points were connected to Enogex's system in Oklahoma and the Texas Panhandle area, areas that have experienced an increase in drilling activity and production. Enogex has secured significant areas of dedication from numerous customers active throughout Enogex's areas of operations.

Customers and Contracts

Residue gas remaining after processing is primarily taken in kind by the producer customers into Enogex's transportation pipelines for redelivery either (a) to on-system customers such as the electric generation facilities of OG&E and PSO, or (b) into downstream interstate pipelines. Enogex's NGLs are typically sold to NGL marketers, its condensate liquid production is typically sold to marketers and refineries and its propane is typically sold in the local market to wholesale distributors. Enogex's key natural gas producer customers include Chesapeake Energy Marketing Inc., Apache Corporation, Scissortail Energy, LLC, Devon Gas Services, L.P. and Samson Resources Company. During 2007, these five customers accounted for approximately 19 percent, 16 percent, eight percent, five percent and four percent, respectively, of Enogex's gathering and processing volumes. During 2007, Enogex's top ten natural gas producer customers accounted for approximately 66 percent of Enogex's gathering and processing volumes.

Competition

Competition for natural gas supply is primarily based on efficiency and reliability of operations, customer service, proximity to existing assets, access to markets and pricing. Competition to gather and process non-dedicated gas is based on providing the producer with the highest total value, which is primarily a function of gathering rate, processing value, system reliability, fuel rate, system run time, construction cycle time and prices at the wellhead. Enogex believes it will be able to continue to compete effectively. Enogex competes with gatherers and processors of all types and sizes, including those affiliated with various producers, other major pipeline companies and various independent midstream entities. Enogex's primary competitors are master limited partnerships who are active in its region, including Atlas Pipeline Partners, L.P., Crosstex Energy LP, DCP Midstream Partners, LP, Enbridge Energy Partners, L.P., Hiland Partners, LP, MarkWest Energy Partners, L.P. and Oneok Partners, L.P. In processing and marketing NGLs, Enogex competes against virtually all other gas processors extracting and selling NGLs in its market area.

Regulation

State regulation of natural gas gathering facilities generally includes various safety, environmental and nondiscriminatory rate and open access requirements and complaint-based rate regulation. Enogex may be subject to state common carrier, ratable take and common purchaser statutes. The common carrier and ratable take statutes generally require gatherers to carry, transport and deliver, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers that purchase gas to purchase without undue discrimination as to source of supply or producer. These statutes may have the effect of restricting Enogex's right to decide with whom it contracts to purchase natural gas or, as an owner of gathering facilities, to decide with whom it contracts to purchase or gather natural gas.

Oklahoma and Texas have each adopted a form of complaint-based regulation of gathering operations that generally allows natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to natural gas gathering open access and rate discrimination. During the 2007 legislative session, the Texas State Legislature passed H.B. 3273 (the "Competition Bill") and H.B. 1920 (the "Lost and Unaccounted for Gas ("LUG") Bill"). The Texas Competition Bill and LUG Bill contain provisions applicable to various natural gas industry participants, including gatherers. The Competition Bill allows the Railroad Commission of Texas ("TRRC") the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering in formal rate proceedings, if a complaint is filed and a determination is made that such a rate is necessary to remedy unreasonable discrimination. It also gives the TRRC specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering, to enforce the requirement that parties participate in an informal complaint process and to impose administrative penalties against purchasers, transporters and gatherers for taking discriminatory actions against shippers and sellers. The LUG Bill modifies the informal complaint process at the TRRC with procedures unique to lost and unaccounted for gas issues. It expands the types of information that can be requested and gives the TRRC the authority to make determinations and issue orders for purposes of preventing waste in specific situations. Both the Competition Bill and the LUG Bill became effective September 1, 2007. Enogex cannot predict what effect, if any, either the Competition Bill or the LUG Bill might have on its gathering operations.

Enogex's gathering operations could be adversely affected should they be subject in the future to the application of state or federal regulation of rates and services. Enogex's gathering operations also may be subject to additional safety and operational regulations relating to the integrity, design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered or adopted from time to time. Enogex cannot predict what effect, if any, such changes might have on its operations, but the industry could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes.

Recent System Expansions

Over the past several years, Enogex has initiated multiple organic growth projects. Currently, in Enogex's gathering and processing business, organic growth capital expenditures are focused on expansions on the east side of Enogex's gathering system, primarily in the Woodford Shale play in southeastern Oklahoma through the construction of new facilities and expansion of existing facilities and the interest in the joint venture, Atoka Midstream LLC, and expansions on the west side of Enogex's gathering system, primarily in the Granite Wash play and Atoka play in the Wheeler County, Texas area, which is located in the Texas Panhandle.

Enogex is expanding in the Woodford Shale play and has several projects either completed or scheduled for completion in 2007 and 2008. For example, in December 2006, Enogex entered into a joint venture arrangement with Pablo Gathering, LLC, a subsidiary of Pablo Energy II, LLC, a Texas-based exploration and production company. The joint venture, Atoka Midstream LLC, constructed, owns and/or operates a gathering system and processing plant and related facilities relating to production in certain areas in southeastern Oklahoma. The gathering system and processing plant were placed in service during the third quarter of 2007. Enogex owns a 50 percent membership interest in Atoka Midstream and acts as the managing member and operator of the facilities owned by the joint venture.

In February 2008, Enogex completed construction on the first phase (22 miles) of a new 30-mile pipeline project that will connect Enogex's Hughes, Coal and Pittsburgh county gathering system with the 30-inch Enogex mainline pipeline to Bennington, Oklahoma, and the 24-inch Enogex mainline pipeline to Wilburton, Oklahoma. The gathering project created additional gathering capacity of 125 MMcf/d for customers desiring low-pressure services with the potential to double this amount with incremental compression investments. The pipeline is complemented by approximately 20,000 horsepower of compression. Also, Enogex recently committed to approximately $50 million in additional expansions in this area primarily during 2008 and 2009 and expects its latest expansion project to be in service by the third quarter of 2008.

In August 2006, Enogex completed a project to expand its gathering pipeline capacity in the Granite Wash/Atoka play in the Wheeler County, Texas area of the Texas Panhandle that has allowed Enogex to benefit from growth opportunities in that marketplace. This project included the addition of a 20-inch gathering header that is intended to be used to collect gas from producers and deliver the gas to multiple outlets and processing plants. Enogex continues to review growth opportunities to expand this project and has recently begun several additional new projects to continue expansion on the west side of its system. In addition, Enogex has installed approximately 11.5 miles of 12-inch pipeline and added approximately 5,400 horsepower of compression to its Billy Rose compressor station.

Technology Improvements

Enogex continues to upgrade its data and information systems in order to improve operational efficiencies and increase profitability of its business and that of its customers.

- Enogex recently completed implementation of an information system which Enogex believes has improved its ability to capture economic opportunities in operating its assets, provide improved customer service and better determine the earnings potential of its various assets and service.

- Enogex has installed a state-of-the-art Supervisory Control and Data Acquisition system which provides a single system for pipeline equipment control, data collection, management and measurement of gas volumes and pressures.

- Information system implemented, together with Enogex’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.

- Enogex continues to enhance its digital asset mapping system that was implemented in May 2006. This system has improved access to pipeline equipment and system information. This information can be used for existing asset management activities including daily operations and maintenance, budgeting, planning and new project development.

- Enogex implemented and continues to improve a new system called ProductionWatch that enhances Enogex’s ability to manage data (such as volume, pressure, temperature, etc.) from Enogex’s meters to its customers. This data service is available to customers by the internet and is offered for a fee. Enogex believes that such data is attractive because it can enable customers to increase gas production and operating efficiency.

Safety and Health Regulation

Enogex is subject to the Natural Gas Pipeline Safety Act of 1968 (“NGPSA”) and the Pipeline Safety Improvement Act of 2002. The NGPSA regulates safety requirements in the design, construction, operation and maintenance of natural gas pipeline facilities while the Pipeline Safety Improvement Act establishes mandatory inspections for all U.S. oil and natural gas transportation pipelines and some gathering lines in high-consequence areas within 10 years. The U.S. Department of Transportation (“DOT”) has developed regulations implementing the Pipeline Safety Improvement Act that will require pipeline operators to implement integrity management programs, including more frequent inspections and other safety protections in areas where the consequences of potential pipeline accidents pose the greatest risk to people and their property.

A four-mile portion of Enogex’s pipeline is also subject to regulation by the DOT under the Accountable Pipeline and Safety Partnership Act of 1996 (the “Hazardous Liquid Pipeline Safety Act”) and comparable state statutes with respect to design, installation, testing, construction, operation, replacement and management of liquid pipeline facilities. The Hazardous Liquid Pipeline Safety Act covers petroleum and petroleum products and requires any entity that owns or operates pipeline facilities to comply with such regulations, to permit access to and copying of records and to file certain reports and provide information as required by the U.S. Secretary of Transportation. These regulations include potential fines and penalties for violations. Enogex believes that it is in material compliance with these Hazardous Liquid Pipeline Safety Act regulations.

States may be preempted by federal law from solely regulating pipeline safety but may assume responsibility for enforcing federal intrastate pipeline regulations and inspection of intrastate pipelines. In the State of Oklahoma, the OCC’s Transportation Division, acting through the Pipeline Safety Department, administers the OCC’s intrastate regulatory program to assure the safe transportation of natural gas, petroleum and other hazardous materials by pipeline. The OCC develops regulations and other approaches to assure safety in design, construction, testing, operation, maintenance and emergency response to pipeline facilities. The OCC derives its authority over intrastate pipeline operations through state statutes and certification agreements with the DOT. A similar regime for safety regulation is in place in Texas and administered by the Texas Railroad Commission. Enogex anticipates that it should be able to comply with currently existing state laws and regulations applicable to pipeline safety without incurring material costs. Enogex’s natural gas pipelines have inspection and compliance programs designed to maintain compliance with pipeline safety and pollution control requirements.

In addition, Enogex is subject to a number of federal and state laws and regulations, including OSHA and comparable state statutes, whose purpose is to protect the safety and health of workers, both generally and within the pipeline industry. In addition, the OSHA hazard communication standard, the EPA community right-to-know regulations under Title III of the federal Superfund Amendment and Reauthorization Act and comparable state statutes require that information be maintained concerning hazardous materials used or produced in Enogex's operations and that this information be provided to employees, state and local government authorities and citizens. Enogex is also subject to OSHA Process Safety Management regulations, which are designed to prevent or minimize the consequences of catastrophic releases of toxic, reactive, flammable or explosive chemicals. These regulations apply to any process which involves a chemical at or above the specified thresholds or any process which involves flammable liquid or gas, pressurized tanks, caverns and wells in excess of 10,000 pounds at various locations. Enogex has an internal program of inspection designed to monitor and enforce compliance with worker safety and health requirements. Enogex believes that it is in material compliance with all applicable laws and regulations relating to worker safety and health.

MARKETING - OERI

General

As discussed above, in connection with the proposed initial public offering of common units of the Partnership, Enogex distributed the stock of OERI to OGE Energy. Enogex has historically utilized, and is expected to continue to utilize, OERI for natural gas marketing, hedging, risk management and other related activities. For the years ended December 31, 2005, 2006 and 2007, OERI recorded revenues from Enogex of approximately $160.6 million, $107.1 million and $95.2 million, respectively, for the sale, at market rates, of natural gas. For the years ended December 31, 2005, 2006 and 2007, Enogex recorded revenues from OERI of approximately $330.5 million, $291.9 million and $304.3 million, respectively, for the sale, at market rates, of natural gas. Enogex has paid, and is expected to continue to pay, certain fees to OERI for providing natural gas marketing, hedging, risk management and other related services.

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.

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 0.8 Bcf in 2006 to approximately 0.7 Bcf in 2007. 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.

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, 2007, approximately 56.1 percent of OERI's service volumes were with electric utilities, local gas distribution companies, pipelines and producers, of which approximately 11.9 percent was with affiliates of OERI. The remaining 43.9 percent of service volumes were to marketers, municipals, cooperatives and industrials. At December 31, 2007, approximately 78.6 percent of the payment exposure was to companies having investment grade ratings with Standard & Poor’s Ratings Services ("Standard & Poor's") and approximately 1.6 percent having less than investment grade ratings. The remaining 19.8 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.

Regulation

The price at which OERI buys and sells natural gas and NGLs is currently not subject to federal regulation and, for the most part, is not subject to state regulation. However, with regard to OERI's physical purchases and sales of these energy commodities, and any related hedging activities that it undertakes, OERI is required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Futures Trading Commission ("CFTC"). The FERC and CFTC hold substantial enforcement authority under the anti-market manipulation laws and regulations, including the ability to assess civil penalties of up to $1 million per day per violation, to order disgorgement of profits and to recommend criminal penalties. Should OERI violate the anti-market manipulation laws and regulations, it could also be subject to related third party damage claims by, among other, marketers, royalty owners and taxing authorities.

ENVIRONMENTAL MATTERS

General

The activities of OG&E and Enogex are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws and regulations can restrict or impact OG&E's and Enogex's business activities in many ways, such as restricting the way it can handle or dispose of its wastes, requiring remedial action to mitigate pollution conditions that may be caused by its operations or that are attributable to former operators, regulating future construction activities to avoid endangered species or enjoining some or all of the operations of facilities deemed in noncompliance with permits issued pursuant to such environmental laws and regulations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where substances or wastes have been disposed or otherwise released into the environment. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of substances or wastes into the environment.

OG&E and Enogex believe that their operations are in substantial compliance with applicable environmental laws and regulations and that compliance with existing federal, state and local environmental laws and regulations will not have a material adverse effect on their business, consolidated financial position or results of operations. Nevertheless, the trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. As a result, there can be no assurance as to amount or timing of future expenditures for environmental compliance or remediation, and actual future expenditures may be different from the amounts currently anticipated. Moreover, OG&E and Enogex cannot assure that future events, such as changes in existing laws, the promulgation of new laws, or the development or discovery of new facts or conditions will not cause it to incur significant costs. Approximately $36.9 million of the Company's capital expenditures budgeted for 2008 are to comply with environmental laws and regulations, of which approximately $36.0 million and $0.9 million are related to OG&E and Enogex, respectively. Approximately $121.4 million of the Company's capital expenditures budgeted for 2009 are to comply with environmental laws and regulations, of which approximately $120.5 million and $0.9 million are related to OG&E and Enogex, respectively. It is estimated that OG&E's and Enogex's total expenditures for capital, operating, maintenance and other costs to preserve and enhance environmental quality will be approximately $94.7 million and $4.5 million, respectively, during 2008 as compared to approximately $63.5 million and $4.9 million, respectively, during 2007. Management continues to evaluate its environmental management systems to ensure compliance with existing and proposed environmental legislation and regulations and to better position it in a competitive market. See Note 16 of Notes to Consolidated Financial Statements for a discussion of environmental matters, including the impact of existing and proposed environmental legislation and regulations.

Hazardous Waste

OG&E's and Enogex's operations generate hazardous wastes that are subject to the Federal Resource Conservation and Recovery Act of 1976 ("RCRA") as well as comparable state laws, which impose detailed requirements for the handling, storage, treatment and disposal of hazardous waste.

For OG&E, these laws impose strict "cradle to grave" requirements on generators regarding their treatment, storage and disposal of hazardous waste. OG&E routinely generates small quantities of hazardous waste throughout its system that include, but are not limited to, waste paint, spent solvents, rechargeable batteries and mercury-containing lamps. These wastes are treated, stored and disposed off-site at facilities that are permitted to manage them. Occasionally, larger quantities of hazardous wastes are generated as a result of power generation-related activities and these larger quantities are managed either on-site or off-site. Nevertheless, through its waste minimization efforts, the majority of OG&E's facilities remain conditionally exempt small quantity generators of hazardous waste.

For Enogex, RCRA currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. Specifically, RCRA excludes from the definition of hazardous waste produced waters and other waste associated with the exploration, development or production of crude oil and natural gas. However, these oil and gas exploration and production wastes may still be regulated under state law or the less stringent solid waste requirements of RCRA. Moreover, ordinary industrial waste such as paint waste, waste solvents and waste compressor oils may be regulated as hazardous waste. The transportation of natural gas in pipelines may also generate some hazardous wastes that are subject to RCRA or comparable state law requirements.

Site Remediation

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 ("CERCLA") (also known as "Superfund") and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Such classes of persons include the current and past owners or operators of sites where a hazardous substance was released, and companies that disposed or arranged for disposal of hazardous substances at offsite locations such as landfills. CERCLA authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. Because OG&E and Enogex utilize various products and generate wastes that either are or otherwise contain CERCLA hazardous substances, OG&E and Enogex could be subject to joint and several, strict liability for the costs of cleaning up and restoring sites where those substances have been released to the environment, for damages to natural resources and for costs of certain health studies. At this time, it is not anticipated that any associated liability will cause any significant impact to OG&E or Enogex.

Enogex currently owns or leases, and has in the past owned or leased, numerous properties that for many years have been used for the measurement, gathering, compression and processing of natural gas. Although Enogex used operating and disposal practices that were standard in the industry at the time, petroleum hydrocarbons or wastes may have been disposed of or released on or under the properties owned or leased by us or on or under other locations where such substances have been taken for disposal. In fact, there is evidence that petroleum spills or releases have occurred at some of the properties owned or leased by Enogex. In addition, some of these properties have been operated by third parties or by previous owners whose treatment and disposal or release of petroleum hydrocarbon or wastes was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, Enogex could be required to remove previously disposed wastes (including waste disposed of by prior owners or operators) or remediate contaminated property (including groundwater contamination, whether from prior owners or operators or other historic activities or spills).

Air Emissions

OG&E's and Enogex's operations are subject to the federal Clean Air Act, as amended, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including electric generating units, natural gas processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that OG&E and Enogex obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations, or subject OG&E and Enogex to monetary penalties, injunctions, conditions or restrictions on operations, and potentially criminal enforcement actions. OG&E and Enogex likely will be required to incur certain capital expenditures in the future for air pollution control equipment and technology in connection with obtaining and maintaining operating permits and approvals for air emissions. OG&E and Enogex believe, however, that their operations will not be materially adversely affected by such requirements, and the requirements are not expected to be any more burdensome to OG&E and Enogex than to any other similarly situated companies. See Note 16 of Notes to Consolidated Financial Statements for a discussion of environmental capital expenditures related to air emissions.

Water Discharges

OG&E's and Enogex's operations are subject to the Federal Water Pollution Control Act of 1972, as amended ("Clean Water Act"), and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into state and federal waters. The discharge of pollutants, including discharges resulting from a spill or leak incident, is prohibited unless authorized by a permit or other agency approval. The

Clean Water Act and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. Any unpermitted release of pollutants from OG&E's and Enogex's power plants, pipelines or facilities could result in administrative, civil and criminal penalties as well as significant remedial obligations.

Other Laws and Regulations

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. In response to such studies, the U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases. In addition, several states have declined to wait on Congress to develop and implement climate control legislation and have already taken legal measures to reduce emissions of greenhouse gases. For instance, at least nine states in the Northeast (Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York and Vermont) and five states in the West (Arizona, California, New Mexico, Oregon and Washington) have passed laws, adopted regulations or undertaken regulatory initiatives to reduce the emission of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Also, as a result of the U.S. Supreme Court's decision on April 2, 2007 in *Massachusetts, et al. v. EPA*, the EPA may be required to regulate greenhouse gas emissions from mobile sources (such as cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. Other nations have already agreed to regulate emissions of greenhouse gases pursuant to the United Nations Framework Convention on Climate Change, also known as the "Kyoto Protocol," an international treaty pursuant to which participating countries (not including the United States) have agreed to reduce their emissions of greenhouse gases to below 1990 levels by 2012. Passage of climate control legislation or other regulatory initiatives by Congress or various states of the U.S. as well as by foreign governmental authorities outside of the U.S., or the adoption of regulations by the EPA and analogous state or foreign governmental agencies that restrict emissions of greenhouse gases in areas in which OG&E and Enogex conduct business could have an adverse effect on their operations and demand for their services or products.

FINANCE AND CONSTRUCTION

Future Capital Requirements

Capital Requirements

The Company's primary needs for capital are related to acquiring or constructing new facilities and replacing or expanding existing facilities at OG&E and Enogex. Other working capital requirements are primarily related to maturing debt, operating lease obligations, hedging activities, natural gas storage, delays in recovering unconditional fuel purchase obligations and fuel clause under and over recoveries. The Company generally meets its cash needs through a combination of cash generated from operations, 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 2008 to 2013 construction program includes continued investment in OG&E's distribution, generation and transmission system and Enogex's pipeline assets. The Company's current estimates of capital expenditures are approximately: 2008 - $1.1 billion (approximately $434.5 million are related to the proposed acquisition of the Redbud power plant), 2009 - $613.9 million, 2010 - $668.1 million, 2011 - $653.4 million, 2012 - $670.8 million and 2013 - $654.1 million. OG&E also has approximately 430 MWs of contracts with qualified cogeneration facilities ("QF") and small power production producers' ("QF contracts") to meet its current and future expected customer needs. OG&E will continue reviewing all of the supply alternatives to these 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.

On October 30, 2007, OG&E announced its goal to increase its wind power generation over the next four years from its current 170 MWs to 770 MWs, and as part of this plan, OG&E expects to issue an RFP in the first quarter of 2008. OG&E also announced its desire to begin building a high-capacity transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma in early to mid-2008 and then eventually to extend the line from Woodward to Guymon, Oklahoma in the Oklahoma Panhandle that would be used by OG&E and others to deliver wind-generated power from western and northwestern Oklahoma to the rest of Oklahoma and other states. OG&E has also previously committed to the SPP to build the Oklahoma portion of the western half of the SPP "X-Plan". The western half of the X-Plan includes transmission lines from Woodward to Tuco, Texas and from Woodward to Spearville, Kansas. The increase in wind power generation and the building of the transmission lines would be subject to numerous regulatory and other approvals, including appropriate regulatory treatment from the OCC and, in the case of the transmission lines, the SPP.

Pension and Postretirement Benefit Plans

During 2007 and 2006, the Company made contributions to its pension plan of approximately $50.0 million and $90.0 million, respectively, to help ensure that the pension plan maintains an adequate funded status. During 2008, the Company may contribute up to $50.0 million to its 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 cash generated from operations, proceeds from the sale of assets, proceeds from the issuance of long and short-term debt and proceeds from the sales of common stock to the public through the Company’s Automatic Dividend Reinvestment and Stock Purchase Plan or other offerings 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.

Issuance of New Long-Term Debt

In January 2008, OG&E issued $200.0 million of 6.45% senior notes due February 1, 2038. The proceeds from the issuance were used to repay commercial paper borrowings.

Short-Term Debt

Short-term borrowings generally are used to meet working capital requirements. At December 31, 2007, the Company had approximately $295.0 million in outstanding commercial paper borrowings. Also, OG&E has the necessary regulatory approvals to incur up to $800 million in short-term borrowings at any time for a two-year period beginning January 1, 2007 and ending December 31, 2008.

In December 2006, the Company and OG&E amended and restated their revolving credit agreements to total in the aggregate $1.0 billion, $600 million for the Company and $400 million for OG&E. Each of the credit facilities has a five-year term with an option to extend the term for two additional one-year periods. In November 2007, the Company and OG&E utilized one of these one-year extensions to extend the maturity of their credit agreements to December 6, 2012. Also, each of these credit facilities has an additional option at the end of the two renewal options to convert the outstanding balance to a one-year term loan. See Note 13 of Notes to Consolidated Financial Statements for a discussion of the Company’s short-term debt activity.

It is currently expected that Enogex will enter into a $250 million credit facility for working capital, capital expenditures, including acquisitions, and other corporate purposes during the first quarter of 2008.

EMPLOYEES

The Company and its subsidiaries had 3,217 employees at December 31, 2007.

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 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 Annual Report on Form 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. As indicated in the settlement agreement with the OCC related to OG&E's Centennial wind farm, OG&E must file for a general rate review that will permit the OCC to issue an order no later than December 31, 2009. Also, during 2007, OG&E incurred storm-related expenses of approximately $35.9 million for which OG&E intends to seek recovery from its customers in its next rate case.

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 cannot assure that the OCC, APSC and the FERC will grant us rate increases in the future or in the amounts we request, and they could instead lower our rates.

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 from 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 position 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.

There is inherent risk of the incurrence of environmental costs and liabilities in our operations due to our handling of natural gas, air emissions related to our operations and historical industry operations and waste disposal practices. For example, an accidental release from one of our facilities could subject us to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. We may be able to recover these costs from insurance. Moreover, the possibility exists that stricter laws, regulations or enforcement policies could significantly increase compliance costs and the cost of any remediation that may become necessary.

There also is growing concern nationally and internationally about global climate change and the contribution of emissions of greenhouse gases including, most significantly, carbon dioxide. This concern has led to increased interest in legislation at the federal level, actions at the state level, as well as litigation relating to greenhouse gas emissions, including a recent U.S. Supreme Court decision holding that the EPA has the authority to regulate carbon dioxide emissions from motor vehicles under the Clean Air Act. Increased pressure for carbon dioxide emissions reduction also is coming from investor organizations and the international community.

Oklahoma and Arkansas have not, at this time, established any mandatory programs to regulate carbon dioxide and other greenhouse gases. However, government officials in these states have declared support for state and federal action on climate change issues. OG&E reports quarterly its carbon dioxide emissions from its generating stations under the EPA's acid rain program and is continuing to evaluate various options for reducing, avoiding, off-setting or sequestering its carbon dioxide emissions. If legislation or regulations are passed at the federal or state levels in the future requiring mandatory reductions of carbon dioxide and other greenhouse gases on generation facilities to address climate change, this could result in significant additional compliance costs that would affect our future consolidated financial position, results of operations and cash flows if such costs are not recovered through regulated rates. See Note 16 of Notes to Consolidated Financial Statements for a further discussion.

We have incurred costs in connection with the Red Rock power plant project that has been terminated and we may not be able to fully recover those costs.

On September 10, 2007, the OCC denied OG&E and PSO's request for pre-approval of their proposed 950 MW Red Rock power plant project. The plant, which was to be built at OG&E's Sooner plant site, was to be 42 percent owned by OG&E, 50 percent owned by PSO and eight percent owned by the OMPA. As a result of the denial for pre-approval, OG&E, PSO and the OMPA agreed to terminate agreements to build and operate the plant. OG&E filed an application with the OCC in December 2007 requesting authorization to defer, and establish a method for recovery of, approximately $14.7 million of Oklahoma jurisdictional costs associated with the Red Rock power plant project. If the request for deferral is not approved, the deferred costs will be expensed.

We may not be able to recover the costs of our substantial planned investment in capital improvements and additions.

Our business plan for OG&E calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades and retrofits and modernizing existing infrastructure as well as other initiatives. Significant portions of OG&E's facilities were constructed many years ago. Older generation equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to maintain efficiency, to comply with changing environmental requirements or to provide reliable operations. OG&E currently provides service at rates approved by one or more regulatory commissions. If these regulatory commissions do not approve adjustments to the rates we charge, we would not be able to recover the costs associated with our planned extensive investment. This could adversely affect our results of operations and financial position. While we may seek to limit the impact of any denied recovery by attempting to reduce the scope of our capital investment, there can no assurance as to the effectiveness of any such mitigation efforts, particularly with respect to previously incurred costs and commitments.

Our planned capital investment program coincides with a material increase in the historic prices of the fuels used to generate electricity. Many of our jurisdictions have fuel clauses that permit us to recover these increased fuel costs through rates without a general rate case. While prudent capital investment and variable fuel costs each generally warrant recovery, in practical terms our regulators could limit the amount or timing of increased costs that we would recover through higher rates. Any such limitation could adversely affect our results of operations and consolidated financial position.

The construction by Enogex of additions or modifications to its existing systems, and the construction of new midstream assets, involves numerous regulatory, environmental, political and legal uncertainties, many of which are beyond Enogex's control and may require the expenditure of significant amounts of capital. These projects, once undertaken, may not be completed on schedule or at the budgeted cost, or at all. Moreover, Enogex's revenues and cash flows may not increase immediately upon the expenditure of funds on a particular project. For instance, if Enogex expands a new pipeline, the construction may occur over an extended period of time, and Enogex may not receive any material increases in revenues or cash flows until the project is completed. In addition, Enogex may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. Since Enogex is not engaged in the exploration for and development of natural gas, Enogex often does not have access to third-party estimates of potential reserves in areas to be developed prior to constructing facilities in those areas. To the extent Enogex relies on estimates of future production in deciding to construct additions to its systems, those estimates may prove to be inaccurate because there are numerous uncertainties inherent in estimating future production. As a result, new facilities may not be able to attract sufficient throughput to achieve expected investment return, which could adversely affect Enogex's results of operations, financial position and cash flows. In addition, the construction of additions to existing gathering and transportation assets may require new rights-of-way prior to constructing new pipelines. Those rights-of-way to connect new natural gas supplies to existing gathering lines may be unavailable and Enogex may not be able to capitalize on attractive expansion opportunities. Additionally, it may become more expensive to obtain new rights-of-way or to renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, Enogex's consolidated financial position, results of operations and cash flows could be adversely affected.

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 and generation 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 implemented a regional energy imbalance service market on February 1, 2007. OG&E has participated, and continues to participate, in the SPP energy imbalance service market to aid in the optimization of its physical assets to serve OG&E's customers. OG&E has not participated in the SPP energy imbalance service market for any speculative trading activities. The SPP purchases and sales are not allocated to individual customers. OG&E records the hourly sales to the SPP at market rates in Operating Revenues and the hourly purchases from the SPP at market rates in Cost of Goods Sold in its Consolidated Financial Statements. 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.

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.

A change in the jurisdictional characterization of some of Enogex's assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of its assets, which may cause its revenues to decline and operating expenses to increase.

Enogex's natural gas gathering and intrastate transportation operations are generally exempt from the jurisdiction of the FERC under the Natural Gas Act of 1938, but FERC regulation may indirectly impact these businesses and the markets for products derived from these businesses. The FERC's policies and practices across the range of its oil and natural gas regulatory activities, including, for example, its policies on interstate open access transportation, ratemaking and capacity release and its promotion of market centers, may indirectly affect intrastate markets. In recent years, the FERC has aggressively pursued pro-competitive policies in its regulation of interstate oil and natural gas pipelines. However, we cannot assure you that the FERC will continue to pursue these same objectives as it considers matters such as pipeline rates and rules and policies that may indirectly affect intrastate natural gas transportation business.

Enogex's natural gas transportation and storage operations are subject to regulation by the FERC pursuant to Section 311 of the NGPA, which could have an adverse impact on its ability to establish transportation and storage rates that would allow it to recover the full cost of operating its transportation and storage facilities, including a reasonable return, and an adverse impact on its consolidated financial position, results of operations or cash flows.

The FERC has jurisdiction over transportation rates charged by Enogex for transporting natural gas in interstate commerce 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. Enogex is currently charging rates for its Section 311 transportation services that were deemed fair and equitable under a rate settlement approved by the FERC for the period from January 1, 2005 until December 31, 2007. On October 1, 2007, Enogex made its required triennial filing for rates and in its filings proposed the new rates to be effective January 1, 2008. A number of interventions have been filed in response to Enogex's triennial filings and some of the intervening parties also filed protests. Enogex has not been able to reach a resolution of the issues with the protesting parties but expects to continue to have discussions with customers and to participate in settlement discussions with the FERC Staff and other interested parties. Enogex has not yet placed the higher proposed rates into effect. Enogex cannot predict what the settlement terms will be or, if not settled, what determinations the FERC will make with respect to this proceeding or what impact, if any, those determinations might have on Enogex's ability to establish transportation rates that would allow Enogex to recover the full cost, including a reasonable return, of operating its transportation facilities and that portion of its storage capacity used in support of transportation services. Accordingly, Enogex cannot predict what impact, if any, such determinations could have on its consolidated financial position, results of operations or cash flows.

Enogex's natural gas transportation, storage and gathering operations are subject to regulation by agencies in Oklahoma and Texas, and that regulation could have an adverse impact on its ability to establish rates that would allow it to recover the full cost of operating its facilities, including a reasonable return, and its consolidated financial position, results of operations or cash flows.

State regulation of natural gas transportation, storage and gathering facilities generally focuses on various safety, environmental and, in some circumstances, nondiscriminatory access requirements and complaint-based rate regulation. Natural gas gathering may receive greater regulatory scrutiny at the state level; therefore, Enogex's natural gas gathering operations could be adversely affected should they become subject to the application of state regulation of rates and services. Enogex's gathering operations also may be or become subject to safety and operational regulations relating to the integrity, design, installation, testing, construction, operation, replacement and management of gathering facilities. Additional rules and legislation pertaining to these matters are considered and, in some instances, adopted from time to time. We cannot predict what effect, if any, such changes might have on Enogex's operations, but Enogex could be required to incur additional capital expenditures and increased costs depending on future legislative and regulatory changes. Other state and local regulations also may affect Enogex's business. Any such state regulation could have an adverse impact on Enogex's business and its consolidated financial position, results of operations or cash flows.

Enogex may incur significant costs and liabilities resulting from pipeline integrity programs and related repairs.

Pursuant to the Pipeline Safety Improvement Act of 2002, the DOT has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines. The regulations require operators to:

- identify potential threats to the public or environment, including "high consequence areas" on covered pipeline segments where a leak or rupture could do the most harm;
- develop a baseline plan to prioritize the assessment of a covered pipeline segment;
- gather data and identify and characterize applicable threats that could impact a covered pipeline segment;
- discover, evaluate and remediate problems in accordance with the program requirements;
- continuously improve all elements of the integrity program;
- continuously perform preventative and mitigation actions;
- maintain a quality assurance process and management-of-change process; and
- establish a communication plan that addresses safety concerns raised by the DOT and state agencies, including the periodic submission of performance documents to the DOT.

During 2007, Enogex incurred approximately $11.7 million of capital expenditures and operating costs to implement its pipeline integrity management program along certain segments of its natural gas pipelines. Enogex currently estimates that it will incur capital expenditures and operating costs of approximately $31.9 million between 2008 and 2011 in connection with its pipeline integrity management program. The estimated capital expenditures and operating costs include Enogex's estimates for the assessment, remediation, prevention or other mitigation that may be determined to be necessary as a result of the integrity management program. At this time, we cannot predict the ultimate costs of compliance with this regulation because those costs will depend on the number and extent of any repairs found to be necessary as a result of the pipeline integrity assessment that is required by the rule. Enogex will continue its pipeline integrity program to assess, remediate and maintain the integrity of its pipelines. The results of these activities could cause Enogex to incur significant and unanticipated capital and operating expenditures for repairs or upgrades deemed necessary to ensure the continued safe and reliable operations of its pipelines.

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 position, cash flows and access to capital.

As a result of accounting irregularities at public companies in general, and energy companies in particular, and investigations by governmental authorities into energy trading activities, public companies, including those 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 companies 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 position, cash flows or access to the capital markets. 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, liabilities and equity. These changes in accounting standards could lead to negative impacts on reported earnings or decreases in assets or increases in liabilities that could, in turn, affect our results of operations and cash flows.

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.

The Energy Policy Act of 2005 gave the FERC authority to establish mandatory electric reliability rules enforceable with monetary penalties. The FERC has approved the North American Electric Reliability Corporation (“NERC”) as the Electric Reliability Organization for North America and delegated to it the development and enforcement of electric transmission reliability rules. It is the Company’s intent to comply with all applicable reliability rules and expediently correct a violation should it occur. The Company is subject to a NERC readiness evaluation and compliance audit every three years and cannot predict the outcome of those audits.

OPERATIONAL 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 that 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 consolidated financial position and results of operations.

Terrorist attacks, and the threat of terrorist attacks, have resulted in increased costs to our business. Continued hostilities in the Middle East or other sustained military campaigns may adversely impact our consolidated financial position, results of operations and cash flows.

The long-term impact of terrorist attacks, such as the attacks that occurred on September 11, 2001, and the magnitude of the threat of future terrorist attacks on the electric utility and natural gas midstream industry in general, and on us in particular, cannot be known. Increased security measures taken by us as a precaution against possible terrorist attacks have resulted in increased costs to our business. Uncertainty surrounding continued hostilities in the Middle East or other sustained military campaigns may affect our operations in unpredictable ways, including disruptions of supplies and markets for our products, and the possibility that our infrastructure facilities could be direct targets of, or indirect casualties of, an act of terror. Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than existing insurance coverage.

Enogex does not own all of the land on which its pipelines and facilities are located, which could disrupt its operations.

Enogex does not own all of the land on which its pipelines and facilities have been constructed, and it is therefore subject to the possibility of more onerous terms and/or increased costs to retain necessary land use if it does not have valid rights of way or if such rights of way lapse or terminate. Enogex obtains the rights to construct and operate its pipelines on land owned by third parties and governmental agencies sometimes for a specific period of time. A loss of these rights, through Enogex's inability to renew right-of-way contracts or otherwise, could cause Enogex to cease operations temporarily or permanently on the affected land, increase costs related to continuing operations elsewhere, reduce its revenue and impair its cash flows.

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

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. During 2007, OG&E incurred storm-related expenses of approximately $35.9 million for which OG&E intends to seek recovery from the its customers in its next rate case.

Natural gas and NGL prices are volatile, and changes in these prices could adversely affect Enogex's results of operations and cash flows.

Enogex is subject to risks due to frequent and often substantial fluctuations in commodity prices. Enogex's results of operations and cash flows could be adversely affected by volatility in natural gas and NGL prices. Enogex's gathering and processing margins generally improve when NGL prices are high relative to the price of natural gas. In the past, the prices of natural gas and NGLs have been extremely volatile, and Enogex expects this volatility to continue. With respect to natural gas, the mid-continent prices for natural gas, as represented by the Inside FERC monthly index posting for Panhandle Eastern Pipe Line Co., Texas, Oklahoma, for the forward month contract in 2006 ranged from a high of $8.76 per MMBtu to a low of $3.54 per MMBtu. In 2007, the same index ranged from a high of $6.82 per MMBtu to a low of $4.73 per MMBtu. Natural gas prices reached relatively high levels in late 2005 due to the impact of Hurricanes Katrina and Rita but have returned to the near $6.00 per MMBtu level experienced over most of the period since 2004. With respect to NGLs, the mid-continent prices for propane, for example, as represented by the average of the Oil Price Information Service daily average posting at the Conway, Kansas market, in 2006 ranged from a high of $1.14 per gallon to a low of $0.90 per gallon. In 2007, the same index ranged from a high of $1.52 per gallon to a low of $0.87 per gallon. Enogex's future revenue and cash flows may be materially adversely affected if the midstream industry experiences significant, prolonged deterioration below general price levels experienced in recent years.

Some factors that affect prices of natural gas and NGLs are beyond our control and changes in these prices could adversely affect Enogex's revenue and cash flows.

The markets and prices for natural gas and NGLs depend upon factors beyond Enogex's control and changes in these prices could adversely affect Enogex's revenue and cash flows. These factors include demand for these commodities, which fluctuates with changes in market and economic conditions and other factors, including the impact of seasonality and weather, general economic conditions, the level of domestic and offshore natural gas production and consumption, the availability of imported natural gas, liquified natural gas and NGLs, actions taken by foreign oil and gas producing nations, the availability of local, intrastate and interstate transportation systems, the availability and marketing of competitive fuels, the impact of energy conservation efforts, technological advances affecting energy consumption and the extent of governmental regulation and taxation.

Enogex's "keep-whole" natural gas processing arrangements and "percent-of-proceeds" and "percent-of-liquids" natural gas processing agreements expose it to risks associated with fluctuations associated with the price of natural gas and NGLs, which could adversely affect Enogex's revenue and cash flows.

Enogex's keep-whole natural gas processing arrangements, which constituted approximately 20 percent of its gross margin and accounted for approximately 68 percent of its natural gas processed volumes during 2007, expose it to fluctuations in the pricing spreads between NGL prices and natural gas prices. Keep-whole processing arrangements generally require a processor of natural gas to keep its shippers whole on a Btu basis by replacing the Btu's of the NGLs extracted from the production stream with Btu's of natural gas. Therefore, if natural gas prices increase and NGL prices do not increase by a corresponding amount, the processor has to replace the Btu's of natural gas at higher prices and processing margins are negatively affected.

Enogex's percent-of-proceeds and percent-of-liquids natural gas processing agreements constituted approximately six percent of its gross margin and accounted for approximately 25 percent of its natural gas processed volumes during 2007. Under these arrangements, Enogex generally gathers raw natural gas from producers at the wellhead, transports the gas through its gathering system, processes the gas and sells the processed gas and/or NGLs at prices based on published index prices. The price paid to producers is based on an agreed percentage of the proceeds of the sale of processed natural gas, NGLs or both or the expected proceeds based on an index price. Enogex refers to contracts in which it shares in specified percentages of the proceeds from the sale of natural gas and NGLs as percent-of-proceeds arrangements and in which it receives proceeds from the sale of NGLs or the NGLs themselves as compensation for its processing services as percent-of-liquids arrangements. These arrangements expose Enogex to risks associated with the price of natural gas and NGLs.

At any given time, Enogex's overall portfolio of processing contracts may reflect a net short position in natural gas (meaning that Enogex was a net buyer of natural gas) and a net long position in NGLs (meaning that Enogex was a net seller of NGLs). As a result, Enogex's margins could be negatively impacted to the extent the price of NGLs decreases in relation to the price of natural gas.

Because of the natural decline in production from existing wells connected to Enogex's systems, Enogex's success depends on its ability to gather new sources of natural gas, which depends on certain factors beyond its control. Any decrease in supplies of natural gas could adversely affect our and Enogex's business and results of operations and cash flows.

Enogex's gathering and transportation systems are connected to or dependent on the level of production from natural gas wells, from which production will naturally decline over time. As a result, Enogex's cash flows associated with these wells will also decline over time. To maintain or increase throughput levels on its gathering and transportation systems and the asset utilization rates at its natural gas processing plants, Enogex must continually obtain new natural gas supplies. The primary factors affecting Enogex's ability to obtain new supplies of natural gas and attract new customers to its assets depends in part on the level of successful drilling activity near these systems, Enogex's ability to compete for volumes from successful new wells and Enogex's ability to expand capacity as needed. If Enogex is not able to obtain new supplies of natural gas to replace the natural decline in volumes from existing wells, throughput on its gathering, processing and transportation facilities would decline, which could have a material adverse effect on its business, results of operations and cash flows.

Enogex's businesses are dependent, in part, on the drilling decisions of others.

All of Enogex's businesses are dependent on the continued availability of natural gas production. Enogex does not have control over the level of drilling activity in the areas of its operations, the amount of reserves associated with the wells or the rate at which production from a well will decline. The primary factor that impacts drilling decisions is natural gas prices. Natural gas prices reached relatively high levels in late 2005 due to the impact of Hurricanes Katrina and Rita but have returned to the near $6.00 per MMBtu level experienced over most of the period since 2004. A sustained decline in natural gas prices could result in a decrease in exploration and development activities in the fields served by Enogex's gathering, processing and transportation facilities, which would lead to reduced utilization of these assets. Other factors that impact production decisions include producers' capital budgets, the ability of producers to obtain necessary drilling and other governmental permits, costs of steel and other commodities, geological considerations, demand for hydrocarbons, the level of reserves, other production and development costs and regulatory changes. Because of these factors, even if new natural gas reserves are discovered in areas served by Enogex's assets, producers may choose not to develop those reserves.

Enogex engages in commodity hedging activities to minimize the impact of commodity price risk, which may have a volatile effect on its earnings and cash flows.

Enogex is exposed to changes in commodity prices in its operations. To minimize the risk of commodity prices, Enogex may enter into physical forward sales or financial derivative contracts to hedge purchase and sale commitments, fuel requirements and inventories of natural gas. However, financial derivative contracts do not eliminate the risk of market supply shortages, which could result in Enogex's inability to fulfill contractual obligations and incurrence of significantly higher energy or fuel costs relative to corresponding sales contracts. Enogex marks its energy trading portfolio to estimated fair market value on a daily basis (mark-to-market accounting), which causes earnings variability. When available, market prices are utilized in determining the value of natural gas and related derivative commodity instruments. For longer-term positions, which are limited to a maximum of 60 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.

Enogex engages in cash flow hedge transactions to manage commodity risk. Hedges of anticipated transactions are documented as cash flow hedges pursuant to Statement of Financial Accounting Standard No. 133, "Accounting for Derivative Instruments and Hedging Activities," and are executed based upon management-established price targets. Enogex utilizes hedge accounting under SFAS No. 133 to manage commodity exposure for contractual length and storage natural gas, percent-of-liquids and keep-whole natural gas, NGL hedges and certain transportation hedges. 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. 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 transaction 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.

As a result of the factors discussed above, Enogex's hedging activities may not be as effective as intended in reducing the volatility of its cash flows. In addition, these activities can result in substantial losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the applicable hedging arrangement, the hedging arrangement is imperfect or ineffective or the hedging policies and procedures are not properly followed or do not work as planned. The steps taken to monitor Enogex's hedging activities may not detect and prevent violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved.

Enogex's results of operations and cash flows may be adversely affected by risks associated with its hedging activities.

Enogex has instituted a hedging program that is intended to reduce the commodity price risk associated with Enogex's keep-whole and percent-of-liquids arrangements. Enogex intends to hedge approximately 70 percent of its NGL volumes when market conditions dictate. As of December 31, 2007, Enogex had hedged approximately 63 percent of its expected non-ethane NGL volumes attributable to these arrangements, along with the natural gas MMBtu equivalent for keep-whole volumes, for 2008, 2009 and 2010. As of December 31, 2007, Enogex had hedged approximately 41 percent of its expected ethane NGL volumes attributable to these arrangements, along with the natural gas MMBtu equivalent for keep-whole volumes, for 2008. Enogex has the option to reject ethane if processing it is not economical. For periods after 2010, management will evaluate whether to enter into any new hedging arrangements, and there can be no assurance that Enogex will enter into any new hedging arrangements. Also, Enogex may seek in the future to further limit its exposure to changes in natural gas and NGL commodity prices and interest rates by using financial derivative instruments and other hedging mechanisms. To the extent Enogex hedges its commodity price and interest rate exposures, Enogex will forego the benefits that otherwise would be experienced if commodity prices or interest rates were to change in Enogex's favor. In addition, even though management monitors Enogex's hedging activities, these activities can result in substantial losses. Such losses could occur under various circumstances, including if a counterparty does not perform its obligations under the applicable hedging arrangement, the hedging arrangement is imperfect or ineffective, or the hedging policies and procedures are not followed or do not work as planned.

Enogex depends on certain key natural gas producer customers for a significant portion of its supply of natural gas and NGLs. The loss of, or reduction in volumes from, any of these customers could result in a decline in its consolidated financial position, results of operations or cash flows.

Enogex relies on certain key natural gas producer customers for a significant portion of its natural gas and NGL supply. During 2007, Chesapeake Energy Marketing Inc., Apache Corporation, Scissortail Energy, LLC, Devon Gas Services, L.P. and Samson Resources Company accounted for approximately 52 percent of Enogex's natural gas and NGL supply. The loss of the natural gas and NGL volumes supplied by these customers, the failure to extend or replace these contracts or the extension or replacement of these contracts on less favorable terms, as a result of competition or otherwise, could have a material adverse effect on Enogex's consolidated financial position, results of operations and cash flows.

Enogex depends on two customers for a significant portion of its firm intrastate transportation and storage services. The loss of, or reduction in volumes from, either of these customers could result in a decline in Enogex's transportation and storage services and its consolidated financial position, results of operations or cash flows.

Enogex provides firm intrastate transportation and storage services to several customers on its system. Enogex's major customers are OG&E and PSO, which is the second largest electric utility in Oklahoma and serves the Tulsa market. As part of the no-notice load following contract with OG&E, Enogex provides natural gas storage services for OG&E. Enogex has been providing natural gas storage services to OG&E since August 2002 when it acquired the Stuart Storage Facility. Enogex provides gas transmission delivery services to all of PSO's natural gas-fired electric generation facilities in Oklahoma under a firm intrastate transportation contract. During 2005, 2006 and 2007, revenues from Enogex's firm intrastate transportation and storage contracts were approximately $95.0 million, $98.1 million and $103.9 million, respectively, of which $47.6 million, $47.6 million and $47.4 million, respectively, was attributed to OG&E and $13.3 million, $13.3 million and $13.3 million, respectively, was attributed to PSO. Enogex's current contract with OG&E expires in April 2009. OG&E has indicated to Enogex that it currently intends to consider competitive bids for gas transportation and storage services prior to the termination of Enogex's current agreement with OG&E, but it is not obligated to do so. Enogex's current contract with PSO expires in January 2013. Even though OG&E is a subsidiary of the Company, there can be no assurance that the current contract with OG&E will be extended or replaced on similar terms or at all. The loss of all or even a portion of the intrastate transportation and storage services for either of these customers, the failure to extend or replace these contracts or the extension or replacement of these contracts on less favorable terms, as a result of competition or otherwise, could have a material adverse effect on Enogex's consolidated financial position, results of operations and cash flows.

Enogex may not be successful in balancing its purchases and sales of natural gas and NGLs, which would increase its exposure to commodity price risk.

In the normal course of business, Enogex purchases or retains from producers and other customers some of the natural gas and NGLs that flow through its natural gas gathering, processing and transportation systems for resale to third parties, including natural gas marketers and end-users. Enogex may not be successful in balancing its purchases and sales. A producer or supplier could fail to deliver contracted volumes or deliver in excess of contracted volumes, or a purchaser could purchase less than contracted volumes. Any of these actions could cause Enogex's purchases and sales to be unbalanced. If Enogex's purchases and sales are unbalanced, it will face increased exposure to commodity price risk and Enogex could have increased volatility in its operating income and cash flows.

If third-party pipelines and other facilities interconnected to Enogex's gathering or transportation facilities become partially or fully unavailable, Enogex's revenues and cash flows could be adversely affected.

Enogex depends upon third-party natural gas pipelines to deliver gas to, and take gas from, its transportation system. Enogex also depends on third-party facilities to transport and fractionate NGLs that it delivers to the third party at the tailgates of its processing plants. Fractionation is the separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale. Since Enogex does not own or operate any of these third-party pipelines or other facilities, their continuing operation is not within Enogex's control. If any of these third-party pipelines or other facilities become partially or fully unavailable, Enogex's revenues and cash flows could be adversely affected.

Enogex's industry is highly competitive, and increased competitive pressure could adversely affect its consolidated financial position, results of operations or cash flows.

Enogex competes with similar enterprises in its respective areas of operation. Some of these competitors are large oil, natural gas and petrochemical companies that have greater financial resources and access to supplies of natural gas and NGLs than Enogex. Some of these competitors may expand or construct gathering, processing, transportation and storage systems that would create additional competition for the services Enogex provides to its customers. In addition, Enogex's customers who are significant producers of natural gas may develop their own gathering, processing, transportation and storage systems in lieu of using Enogex's. Enogex's ability to renew or replace existing contracts with its customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of its competitors and customers. All of these competitive pressures could have a material adverse effect on Enogex's consolidated financial position, results of operations and cash flows.

Gathering, processing, transporting and storing natural gas involves many hazards and operational risks, some of which may not be fully covered by insurance. If a significant accident or event occurs that is not fully insured, Enogex's operations and financial results could be adversely affected.

Gathering, processing, transporting and storing natural gas involves many hazards and operational risks, including:

- damage to pipelines and plants, related equipment and surrounding properties caused by tornadoes, floods, earthquakes, fires and other natural disasters and acts of terrorism;
- inadvertent damage from third parties, including construction, farm and utility equipment;
- leaks of natural gas, NGLs and other hydrocarbons or losses of natural gas or NGLs as a result of the malfunction of equipment or facilities; and
- fires and explosions.

These and other risks could result in substantial losses due to personal injury and loss of life, severe damage to and destruction of property and equipment and pollution or other environmental damage and may result in curtailment or suspension of Enogex's related operations. Enogex's insurance is currently provided under the Company's insurance programs. Enogex is not fully insured against all risks inherent to its business. Enogex is not insured against all environmental accidents that might occur, which may include toxic tort claims. In addition, Enogex may not be able to maintain or obtain insurance of the type and amount desired at reasonable rates. Moreover, in some instances, significant claims by the Company may limit or eliminate the amount of insurance proceeds available Enogex. As a result of market conditions, premiums and deductibles for certain of the Company's insurance policies have increased substantially, and could escalate further. In some instances, insurance could become unavailable or available only for reduced amounts of coverage. If a significant accident or event occurs that is not fully insured, it could adversely affect Enogex's operations and financial results.

FINANCIAL 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 retirement and postretirement plans that cover substantially all of our employees. Assumptions related to future costs, returns on investments, interest rates and other actuarial assumptions with respect to the defined benefit retirement and postretirement plans have a significant impact on our earnings and funding requirements. Based on our assumptions at December 31, 2007, 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.

All employees hired prior to February 1, 2000 participate in defined benefit and postretirement plans. If these employees retire when they become eligible for retirement over the next several years, or if our plan experiences adverse market returns on its investments, or if interest rates materially fall, our pension expense and contributions to the plans could rise substantially over historical levels. The timing and number of employees retiring and selecting the lump-sum payment option could result in pension settlement charges that could materially affect our results of operations if we are unable to recover these costs through our electric rates. In addition, assumptions related to future costs, returns on investments, interest rates and other actuarial assumptions, including projected retirements, have a significant impact on our results of operations and consolidated financial position. Those assumptions are outside of our control.

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 face certain human resource risks associated with the availability of trained and qualified labor to meet our future staffing requirements.

Workforce demographic issues challenge employers nationwide and are of particular concern to the electric utility and natural gas pipeline industry. The median age of utility and natural gas pipeline workers is significantly higher than the national average. Over the next three years, approximately 32 percent of our current employees will be eligible to retire with full pension benefits. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, may adversely affect our ability to manage and operate our business.

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, 2007, we had outstanding indebtedness and other liabilities of approximately $3.6 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.

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 the Company. 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 the Company 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 the Company. 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.

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.

Any reductions in our credit ratings could increase our financing costs and the cost of maintaining certain contractual relationships or limit our ability to obtain financing on favorable terms.

We cannot assure that any of our current ratings or the ratings of 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 so warrant. Our ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruption as experienced with the market turmoil in August 2007. 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 downgrade 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. Any future downgrade would also lead to higher long-term borrowing costs and, if below investment grade, would require us to post cash collateral or letters of credit. Also, any downgrade below investment grade at OERI could require us to issue guarantees to support some of OERI's marketing operations.

Any negative change in OERI's creditworthiness could adversely affect Enogex's ability to engage in hedging transactions or adversely affect the prices and terms upon which hedging transactions occur.

Enogex historically has conducted its hedging activities with OERI as its counterparty. OERI, in turn, has engaged in back-to-back hedging transactions with third parties. The willingness of those third parties to serve as counterparties on OERI's hedging transactions depends on OERI's creditworthiness. Any negative change in OERI's creditworthiness could adversely affect OERI's and Enogex's ability to enter into hedging transactions, or the prices and terms upon which such transactions may be effected.

Enogex's debt levels may limit its flexibility in obtaining additional financing and in pursuing other business opportunities.

Enogex expects to enter into a $250 million credit facility for working capital, capital expenditures, including acquisitions, and other corporate purposes during the first quarter of 2008. The new credit facility is expected to include an accordion feature that would allow Enogex to seek an additional $250 million of lending commitments. Following the Offering, Enogex will continue to have the ability to incur additional debt, subject to limitations in its credit facility. The levels of Enogex's debt could have important consequences, including the following:

- the ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or the financing may not be available on favorable terms;
- a portion of cash flows will be required to make interest payments on the debt, reducing the funds that would otherwise be available for operations, future business opportunities and distributions;
- Enogex's debt level will make it more vulnerable to competitive pressures or a downturn in its business or the economy generally; and
- Enogex's debt level may limit its flexibility in responding to changing business and economic conditions.

Enogex's ability to service its debt will depend upon, among other things, Enogex's future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond Enogex's control. If operating results are not sufficient to service its current or future indebtedness, Enogex may be forced to take actions such as reducing or delaying business activities, acquisitions, investments or capital expenditures, selling assets, restructuring or refinancing debt, or seeking additional equity capital. These actions may not be effected on satisfactory terms, or at all.

We are exposed to the credit risk of our key customers and counterparties, and any material nonpayment or nonperformance by our key customers and counterparties could adversely affect our consolidated financial position, results of operations and cash flows.

We are exposed to credit risks in our generation, retail distribution, pipeline and energy trading operations. Credit risk includes the risk that customers and counterparties that owe us money or energy will breach their obligations. If such parties 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

OG&E owns and operates an interconnected electric generation, transmission and distribution system, located in Oklahoma and western Arkansas, which included nine generating stations with an aggregate capability of approximately 6,229 MWs at December 31, 2007. 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	2007 Capacity Factor (A)	Unit Capability (MW)	Station Capability (MW)
Muskogee	3	1956	Steam-Turbine	Gas	Base Load	18.9%	170.5	
	4	1977	Steam-Turbine	Coal	Base Load	62.0%	510.5	
	5	1978	Steam-Turbine	Coal	Base Load	47.6%	517.3	
	6	1984	Steam-Turbine	Coal	Base Load	72.6%	515.0	1,713.3
Seminole	1	1971	Steam-Turbine	Gas	Base Load	23.2%	506.0	
	1GT	1971	Combustion-Turbine	Gas	Peaking	0.1%(B)	17.0	
	2	1973	Steam-Turbine	Gas	Base Load	23.8%	500.5	
	3	1975	Steam-Turbine	Gas/Oil	Base Load	31.9%	519.0	1,542.5
Sooner	1	1979	Steam-Turbine	Coal	Base Load	78.4%	540.0	
	2	1980	Steam-Turbine	Coal	Base Load	59.1%	512.0	1,052.0
Horseshoe	6	1958	Steam-Turbine	Gas/Oil	Base Load	15.3%	171.7	
Lake	7	1963	Combined Cycle	Gas/Oil	Base Load	16.4%	209.0	
	8	1969	Steam-Turbine	Gas	Base Load	14.6%	387.0	
	9	2000	Combustion-Turbine	Gas	Peaking	3.3%(B)	45.5	
	10	2000	Combustion-Turbine	Gas	Peaking	3.2%(B)	45.5	858.7
Mustang	1	1950	Steam-Turbine	Gas	Peaking	2.1%(B)	54.0	
	2	1951	Steam-Turbine	Gas	Peaking	2.1%(B)	50.0	
	3	1955	Steam-Turbine	Gas	Base Load	19.8%	113.4	
	4	1959	Steam-Turbine	Gas	Base Load	31.7%	241.0	
	5A	1971	Combustion-Turbine	Gas/Jet Fuel	Peaking	0.7%(B)	34.0	
	5B	1971	Combustion-Turbine	Gas/Jet Fuel	Peaking	1.0%(B)	34.0	526.4
McClain (C)	1	2001	Combined Cycle	Gas	Base Load	83.0%	363.2	363.2
Woodward	1	1963	Combustion-Turbine	Gas	Peaking	0.2%(B)	9.5	9.5
Enid	1	1965	Combustion-Turbine	Gas	Peaking	0.8%	11.1	
	2	1965	Combustion-Turbine	Gas	Peaking	0.3%	10.5	
	3	1965	Combustion-Turbine	Gas	Peaking	---%	11.5	
	4	1965	Combustion-Turbine	Gas	Peaking	0.5%	10.5	43.6
Total Generating Capability (all stations, excluding winds station)								6,109.2

Station	Year Installed	Location	Number of units	Fuel Capability	2007 Capacity Factor (A)	Unit Capability (MW)	Station Capability (MW)
Centennial	2007	Woodward, OK	80	Wind	33.7%	1.5	120.0
Total Generating Capability (wind station)							120.0

(A) 2007 Capacity Factor = 2007 Net Actual Generation / (2007 Net Maximum Capacity (Nameplate Rating in MWs) x Period Hours (8,760 Hours)).
(B) Peaking units, which are used when additional capacity is required, are also necessary to meet the SPP reserve margins.
(C) Represents OG&E's 77 percent ownership interest in the McClain Plant.

At December 31, 2007, OG&E's transmission system included: (i) 48 substations with a total capacity of approximately 9.5 million kilo Volt-Amps ("kVA") and approximately 4,025 structure miles of lines in Oklahoma; and (ii) seven substations with a total capacity of approximately 2.5 million kVA and approximately 259 structure miles of lines in Arkansas. OG&E reclassified some substation assets as transmission assets that historically have been distribution assets. This was done in order to comply with the SPP's FERC-approved transmission definition, which resulted in an increase in transmission substations and transformer capacity, as compared to 2006. OG&E's distribution system included: (i) 342 substations with a total capacity of approximately 8.6 million kVA, 23,854 structure miles of overhead lines, 1,833 miles of underground conduit and 9,756 miles of underground conductors in Oklahoma; and (ii) 36 substations with a total capacity of approximately 1.0 million kVA, 1,906 structure miles of overhead lines, 178 miles of underground conduit and 647 miles of underground conductors in Arkansas.

OG&E owns approximately 140,133 square feet of office space at its executive offices at 321 North Harvey, Oklahoma City, Oklahoma 73101. In addition to its executive offices, OG&E owns numerous facilities throughout its service territory that support its operations. These facilities include, but are not limited to, district offices, fleet and equipment service facilities, operation support and other properties.

Enogex

Enogex's real property falls into two categories: (1) parcels that it owns in fee and (2) parcels in which Enogex's interest derives from leases, easements, rights-of-way, permits or licenses from landowners or governmental authorities permitting the use of such land for its operations. Certain of Enogex's processing plants and related facilities are located on land Enogex owns in fee title, and Enogex believes that it has satisfactory title to these lands. The remainder of the land on which Enogex's plants and related facilities are located is held by Enogex pursuant to ground leases between Enogex, as lessee, and the fee owner of the lands, as lessors. Enogex, or its predecessors, have leased these lands for many years without any material challenge known to us or Enogex relating to the title to the land upon which the assets are located, and Enogex believes that it has satisfactory leasehold estates to such lands. Enogex has no knowledge of any challenge to the underlying fee title of any material lease, easement, right-of-way, permit or license held by Enogex or to its title to any material lease, easement, right-of-way, permit or lease, and Enogex believes that it has satisfactory title to all of its material leases, easements, rights-of-way, permits and licenses.

Record title to some of Enogex's assets may continue to be held by prior owners until Enogex has made the appropriate filings in the jurisdictions in which such assets are located. Title to some of Enogex's assets may be subject to encumbrances. We believe that none of such encumbrances should materially detract from the value of Enogex's properties or our interest in those properties or should materially interfere with Enogex's use of them in the operation of its business. Substantially all of Enogex's pipelines are constructed on rights-of-way granted by the apparent owners of record of the properties. Lands over which pipeline rights-of-way have been obtained may be subject to prior liens that have not been subordinated to the rights-of-way grants.

At December 31, 2007, Enogex and its subsidiaries owned: (i) approximately 5,534 miles of intrastate natural gas gathering pipelines in Oklahoma and Texas; (ii) approximately 2,318 miles of intrastate natural gas transportation pipelines in Oklahoma and Texas; (iii) two natural gas storage facilities in Oklahoma operating at a working gas level of approximately 23 Bcf with approximately 650 MMcf/d of maximum withdrawal capacity and approximately 650 MMcf/d of injection capacity; and (iv) six operating natural gas processing plants, with a total inlet capacity of approximately 723 MMcf/d, a 50 percent interest in an additional natural gas processing plant with an inlet capacity of approximately 20 MMcf/d and two idle natural gas processing plants, all located in Oklahoma. The following table sets forth information with respect to Enogex's active natural gas processing plants:

Processing Plant	Year Installed	Type of Plant	Fuel Capability	2007 Average Daily Inlet Volumes (MMcf/d)	Inlet Capacity (MMcf/d)
Calumet (A)	1969	Lean Oil	Gas	102	250
Canute (B)	1996	Cryogenic	Electric	46	60
Cox City (B)	1994	Cryogenic	Gas/Electric	179	180
Harrah (A)	1994	Cryogenic	Gas/Electric	16	38
Thomas (A)	1981	Cryogenic	Gas	120	135
Wetumka (A)	1983	Cryogenic	Gas	39	60
Atoka (C)	2007	Refrigeration	Electric	15	20
				517	743

(A) These processing plants are located on property that Enogex owns in fee.
(B) These processing plants are located on leased rental property.
(C) Atoka was placed into operation in August 2007. The above amount represents Enogex's 50 percent ownership interest in Atoka.

Enogex occupies approximately 109,493 square feet of office space at its executive offices at 600 Central Park Two, 515 Central Park Drive, Oklahoma City, Oklahoma 73105 under a lease that expires March 31, 2012. Although Enogex may require additional office space as its business expands, Enogex believes that its existing facilities are adequate to meet its needs for the immediate future. In addition to its executive offices, Enogex owns numerous facilities throughout its service territory the support its operations. These facilities include, but are not limited to, district offices, fleet and equipment service facilities, compressor station facilities, operation support and other properties.

During the three years ended December 31, 2007, the Company's gross property, plant and equipment (excluding construction work in progress) additions were approximately $1.3 billion and gross retirements were approximately $305.8 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 18.6 percent of total property, plant and equipment at December 31, 2007.

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 16 and 17 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. *United States of America ex rel., Jack J. Grynberg v. Enogex Inc., Enogex Services Corporation and OG&E.* (U.S. 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.* (U.S. District Court for the Eastern District of Louisiana, Case No. 97-2089; U.S. District Court for the Western District of Oklahoma, Case No. 97-1009M.). On June 15, 1999, the Company was served with the 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 Federal government, alleges: (a) 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 underreporting and underpayment of gas royalties owed to the Federal government; (b) certain provisions generally found in gas purchase contracts are improper; (c) transactions by affiliated companies are not arms-length; (d) excess processing cost deduction; and (e) 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 Federal government can intervene and take over such actions from the relator. The Department of Justice, on behalf of the Federal government, decided not to intervene in this action.

The 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 ("MDL") 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 U.S. District Court for the District of Wyoming.

In October 2002, the court granted the Department of Justice's motion to dismiss certain of the plaintiff's claims and issued an order dismissing the plaintiff's valuation claims against all defendants. Various procedural motions have been filed. 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 in 2005 and the special master ruled that OG&E and all Enogex parties named in these proceedings should be dismissed. This ruling was appealed to the District Court of Wyoming.

On October 20, 2006, the District Court of Wyoming ruled on Grynberg's appeal, following and confirming the recommendation of the special master dismissing all claims against Enogex Inc., Enogex Services Corp., Transok, Inc. and OG&E, for lack of subject matter jurisdiction. Judgment was entered on November 17, 2006 and Grynberg filed his notice of appeal with the District Court of Wyoming. The defendants filed motions for attorneys' fees on various bases on January 8, 2007. The defendants also filed for other legal costs on December 18, 2006. A hearing on these motions was held on April 24, 2007, at which time the judge took these motions under advisement. Grynberg has also filed appeals with the Tenth Circuit Court of Appeals. In compliance with the Tenth Circuit's June 19, 2007 scheduling order, Grynberg filed appellants' opening brief on July 31, 2007 and the appellees' consolidated response briefs were filed on November 21, 2007. Also, on December 5, 2007, the Company filed a notice of its intent to file a separate response brief, which the Company filed on

January 11, 2008. At this time, oral arguments are preliminarily scheduled for the week of September 22, 2008. 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.

2. *Will Price, et al. v. El Paso Natural Gas Co., et al.* (Price I). On September 24, 1999, various subsidiaries of the Company were served with a class action petition filed in the District Court of Stevens County, Kansas by Quinque Operating Company and other named plaintiffs alleging the mismeasurement of natural gas on non-federal lands. On April 10, 2003, the court entered an order denying class certification. On May 12, 2003, the 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 class action petition, and the court granted the motion on July 28, 2003. In its amended petition (the "Fourth Amended Petition"), OG&E and Enogex Inc. were omitted from the case but two of the Company's subsidiary entities remained as defendants. The plaintiffs' Fourth Amended Petition seeks class certification and alleges that approximately 60 defendants, including two of the Company's subsidiary entities, have improperly measured the volume of natural gas. The Fourth Amended Petition asserts theories of civil conspiracy, aiding and abetting, accounting and unjust enrichment. In their briefing on class certification, the plaintiffs seek to also allege a claim for conversion. The plaintiffs seek unspecified actual damages, attorneys' fees, costs and pre-judgment and post-judgment interest. The plaintiffs also reserved the right to seek punitive damages.

Discovery was conducted on the class certification issues, and the parties fully briefed these same issues. A hearing on class certification issues was held April 1, 2005. In May 2006, the court heard oral argument on a motion to intervene filed by Colorado Consumers Legal Foundation, which is claiming entitlement to participate in the putative class action. The court has not yet ruled on the motion to intervene.

On July 2, 2007, the court ordered the plaintiffs and defendants to file proposed findings of facts and conclusions of law on class certification by July 31, 2007. On July 31, 2007, the two subsidiary entities of the Company filed their proposed findings of fact and conclusions of law regarding conflict of law issues and the coordinated defendants filed their proposed findings of facts and conclusions of law on class certification.

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, et al. v. El Paso Natural Gas Co., et al.* (Price II). On May 12, 2003, the plaintiffs (same as those in Price I above) filed a new class action petition in the District Court of Stevens County, Kansas naming the same defendants and asserting substantially identical legal and/or equitable theories as in the amended petition of the Price I case. The plaintiffs allege that the defendants mismeasured the Btu content of natural gas obtained from or measured for the plaintiffs. In their briefing on class certification, the plaintiffs seek to also allege a claim for conversion. The plaintiffs seek unspecified actual damages, attorneys' fees, costs and pre-judgment and post-judgment interest. The plaintiffs also reserved the right to seek punitive damages.

Discovery was conducted on the class certification issues, and the parties fully briefed these same issues. A hearing on class certification issues was held April 1, 2005. In May 2006, the court heard oral argument on a motion to intervene filed by Colorado Consumers Legal Foundation, which is claiming entitlement to participate in the putative class action. The court has not yet ruled on the motion to intervene.

On July 2, 2007, the court ordered the plaintiffs and defendants to file proposed findings of facts and conclusions of law on class certification by July 31, 2007. On July 31, 2007, the two subsidiary entities of the Company filed their proposed findings of fact and conclusions of law regarding conflict of law issues and the coordinated defendants filed their proposed findings of facts and conclusions of law on class certification.

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. *TCEQ Notice of Enforcement.* A Notice of Enforcement Action ("NOE") by the Texas Natural Resource Conservation Commission (now known as the Texas Commission on Environmental Quality ("TCEQ")) was issued to Enogex Products Corporation ("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. By agreed order dated October 19, 2006, the TCEQ agreed to a fine of less than $0.1 million.

Pursuant to the Agreement of Sale and Purchase with the purchaser, Products retained some liability for amounts that Belvan pays to the TCEQ relating to this NOE not to exceed approximately $0.1 million. This amount is fully reserved on Products' books.

5. *Oklahoma Royalty Lawsuit.* On July 22, 2005, Enogex along with certain other unaffiliated co-defendants was 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 Enogex and its subsidiaries, 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. Enogex and its subsidiaries 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 the Enogex companies. On September 19, 2005, the co-defendants, BP America, Inc. and BP America Production Co. (collectively, "BP"), 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. On May 17, 2006, the plaintiffs filed an amended petition against Enogex and its subsidiaries. Enogex and its subsidiaries filed a motion to dismiss the amended petition on August 2, 2006. The hearing on the dismissal motion was held on November 20, 2006 and the court denied Enogex's motion. Enogex companies filed an answer to the amended petition and BP's cross claim on January 16, 2007. Based on Enogex's investigation to date, the Company believes these claims and cross claims in this lawsuit are without merit and intends to continue vigorously defending this case.

6. *Franchise Fee Lawsuit.* On June 19, 2006, two OG&E customers brought a putative class action, on behalf of all similarly situated customers, in the District Court of Creek County, Oklahoma, challenging certain charges on OG&E's electric bills. The plaintiffs claim that OG&E improperly charged sales tax based on franchise fee charges paid by its customers. The plaintiffs also challenge certain franchise fee charges, contending that such fees are more than is allowed under Oklahoma law. OG&E's motion for summary judgment was denied by the trial judge. OG&E filed a writ of prohibition at the Oklahoma Supreme Court asking the court to direct the trial court to dismiss the class action suit. In January 2007, the Oklahoma Supreme Court "arrested" the District Court action until, and if, the propriety of the complaint of billing practices is determined by the OCC. The plaintiffs have not filed any action with the OCC to date. OG&E believes that this case is without merit.

7. *Patent Infringement Lawsuit.* In Ronald A. Katz Technology Licensing, L.P. v. OGE Energy Corp., et al. (U.S. District Court for the Western District of Oklahoma (Civil Action No. 5:07-CV-00650-C)), Ronald A. Katz Technology Licensing, L.P. ("RAKTL") sued the Company and OG&E on June 7, 2007 for patent infringement. RAKTL alleges that OG&E, by operating automated telephone systems that allow OG&E's customers to access account information, sign-up for new service, transfer service, arrange for an installment payment plan, make a payment on an account, request a duplicate bill, report an electricity outage, and perform various other functions, has infringed 13 of RAKTL's patents and continues to infringe four of RAKTL's patents. RAKTL seeks unspecified damages resulting from OG&E's alleged infringement, including treble damages, as well as a permanent injunction enjoining OG&E from continuing the alleged infringement. RAKTL has previously filed similar actions against numerous companies and these previously filed cases have been consolidated pursuant to MDL proceedings in the U.S. District Court for the Central District of California. The Judicial Panel on MDL issued a conditional transfer order on June 20, 2007, consolidating this case with the currently pending MDL proceedings, In re Katz Interactive Call Processing Patent Litigation Case No. MDL-1816. On September 12, 2007, RAKTL filed its reply to the counterclaims of the Company defendants in the Central District of California. An initial conference was held on October 30, 2007. While the Company cannot predict the outcome of this lawsuit at this time, the Company intends to vigorously defend this case and believes that its ultimate resolution will not be material to the Company's consolidated financial position or results of operations.

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 28, 2008:

Name	Age	Title
Peter B. Delaney	54	Chairman of the Board, President and Chief Executive Officer - OGE Energy Corp. and Chief Executive Officer - Enogex Inc.
Danny P. Harris	52	Senior Vice President and Chief Operating Officer - OGE Energy Corp. and President - Enogex Inc.
James R. Hatfield	50	Senior Vice President and Chief Financial Officer - OGE Energy Corp.
Carla D. Brockman	48	Vice President - Administration / Corporate Secretary - OGE Energy Corp.
Gary D. Huneryager	57	Vice President - Internal Audits - OGE Energy Corp.
S. Craig Johnston	47	Vice President - Strategic Planning and Marketing - OGE Energy Corp.
Jesse B. Langston	45	Vice President - Utility Commercial Operations - OG&E
Cary W. Martin	55	Vice President - Human Resources - OGE Energy Corp.
Howard W. Motley	59	Vice President - Regulatory Affairs - OG&E
Reid V. Nuttall	50	Vice President - Enterprise Information and Performance - OGE Energy Corp.
Melvin H. Perkins, Jr.	59	Vice President - Power Delivery - OG&E
Paul L. Renfrow	51	Vice President - Public Affairs - OGE Energy Corp.
John Wendling Jr.	51	Vice President - Power Supply - OG&E
Deborah S. Fleming	52	Treasurer; Vice President - Treasurer - OG&E
Scott Forbes	50	Controller and Chief Accounting Officer - OGE Energy Corp.
Jerry A. Peace	45	Chief Risk Officer - OGE Energy Corp.
John D. Rhea	39	Assistant Corporate Secretary and Corporate Compliance Officer - OGE Energy Corp.

No family relationship exists between any of the Executive Officers of the Registrant. Messrs. Delaney, Harris Hatfield, Huneryager, Johnston, Martin, Nuttall, Renfrow, Forbes, Peace and Rhea and 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 22, 2008.

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

Name	Business Experience	
Peter B. Delaney	2007 – Present:	Chairman of the Board, President and Chief Executive Officer of OGE Energy Corp. and OG&E
	2007 – Present:	Chief Executive Officer of the General Partner of the Partnership
	2003 – Present:	Chief Executive Officer – Enogex Inc.
	2007:	President and Chief Operating Officer of OGE Energy Corp. and OG&E
	2004 – 2007:	Executive Vice President and Chief Operating Officer of OGE Energy Corp. and OG&E
	2003 – 2004:	Executive Vice President, Finance and Strategic Planning – OGE Energy Corp.
	2003 – 2005:	President – Enogex Inc.
Danny P. Harris	2007 – Present:	Senior Vice President and Chief Operating Officer – OGE Energy Corp. and OG&E and President – Enogex Inc.
	2007 – Present:	President of the General Partner of the Partnership
	2005 – 2007:	Senior Vice President – OGE Energy Corp. and President and Chief Operating Officer – Enogex Inc.
	2003 – 2005:	Vice President and Chief Operating Officer – Enogex Inc.
James R. Hatfield	2003 – Present:	Senior Vice President and Chief Financial Officer of OGE Energy Corp. and OG&E
Carla D. Brockman	2005 – Present:	Vice President – Administration / Corporate Secretary of OGE Energy Corp. and OG&E
	2007 – Present:	Corporate Secretary of the General Partner of the Partnership
	2003 – 2005:	Corporate Secretary of OGE Energy Corp. and OG&E
Gary D. Huneryager	2005 – Present:	Vice President – Internal Audits of OGE Energy Corp. and OG&E
	2003 – 2005:	Internal Audit Officer of OGE Energy Corp. and OG&E
S. Craig Johnston	2007 – Present:	Vice President – Strategic Planning and Marketing of OGE Energy Corp. and OG&E
	2004 – 2007:	Senior Vice President – Worldwide Oil & Gas Markets – Air Liquide (industrial gases company)
	2003 – 2004:	Manager – Strategy & Business Optimization – ConocoPhillips (international oil company)
Jesse B. Langston	2006 – Present:	Vice President – Utility Commercial Operations - OG&E
	2005 – 2006:	Director – Utility Commercial Operations - OG&E
	2004 – 2005:	Director – Corporate Planning - OG&E
	2003:	Manager – Corporate Planning - OG&E
Cary W. Martin	2006 – Present:	Vice President – Human Resources of OGE Energy Corp. and OG&E
	2005 – 2006:	Vice President – Global Human Resources – SPX Corporation
	2004 – 2005:	Vice President – Human Resources, Technical and Industrial Systems – SPX Corporation
	2003 – 2004:	Vice President – Human Resources, Communication and Technology Systems – SPX Corporation (global industrial manufacturer)
Howard W. Motley	2006 – Present:	Vice President – Regulatory Affairs - OG&E
	2004 – 2006:	Director – Regulatory Affairs and Strategy - OG&E
	2003 – 2004:	Director – Regulatory Strategies and Utility Resources - OG&E
	2003:	Manager – Regulatory Strategies and Utility Resources - OG&E

Name		Business Experience
Reid V. Nuttall	2006 – Present:	Vice President – Enterprise Information and Performance of OGE Energy Corp. and OG&E
	2005 – 2006:	Vice President – Enterprise Architecture – National Oilwell Varco (oil and gas equipment company)
	2003 – 2005:	Chief Information Officer, Vice President – Information Technology – Varco International (oil and gas equipment company)
Melvin H. Perkins, Jr.	2007 – Present:	Vice President – Power Delivery - OG&E
	2004 – 2007:	Vice President – Transmission - OG&E
	2003:	Director – Transmission Policy - OG&E
Paul L. Renfrow	2005 – Present:	Vice President – Public Affairs of OGE Energy Corp. and OG&E
	2003 – 2005:	Director – Public Affairs
John Wendling, Jr.	2007 – Present:	Vice President – Power Supply - OG&E
	2005 – 2007:	Director, Power Plant Operations - OG&E
	2004 – 2005:	Plant Manager, Sooner Power Plant - OG&E
	2003 – 2004:	Plant Manager, Horseshoe Lake/Mustang Power Plants - OG&E
Deborah S. Fleming	2006 – Present:	Vice President – Treasurer - OG&E
	2003 – Present:	Treasurer of OGE Energy Corp. and OG&E
	2003:	Assistant Treasurer – Williams Cos. Inc. (energy company)
Scott Forbes	2005 – Present:	Controller and Chief Accounting Officer of OGE Energy Corp. and OG&E
	2003 – 2005:	Chief Financial Officer – First Choice Power (retail electric provider)
	2003 – 2005:	Senior Vice President and Chief Financial Officer – Texas New Mexico Power Company (electric utility)
Jerry A. Peace	2008 – Present:	Chief Risk Officer of OGE Energy Corp. and OG&E
	2004 – 2008:	Chief Risk Officer and Compliance Officer of OGE Energy Corp. and OG&E
	2003 – 2004:	Chief Risk Officer of OGE Energy Corp. and OG&E
John D. Rhea	2007 – Present:	Assistant Corporate Secretary and Corporate Compliance Officer of OGE Energy Corp. and OG&E
	2006 – 2007:	Assistant General Counsel and Director of Corporate Compliance – El Paso Electric Company
	2005 – 2006:	Assistant General Counsel and Director of Corporate Compliance and Risk Management – El Paso Electric Company
	2003 – 2005:	Assistant General Counsel and Director of Corporate Compliance – El Paso Electric Company (electric utility)

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 Stock Exchange 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.

2006	Dividend Paid	Price High	Price Low
First Quarter	$ 0.3325	$ 29.60	$ 26.34
Second Quarter	0.3325	35.07	28.29
Third Quarter	0.3325	39.15	34.65
Fourth Quarter	0.3325	40.58	36.10

2007	**Dividend Paid**	**Price High**	**Price Low**
First Quarter	**$ 0.3400**	**$ 41.30**	**$ 36.39**
Second Quarter	**0.3400**	**39.65**	**33.65**
Third Quarter	**0.3400**	**37.59**	**29.12**
Fourth Quarter	**0.3400**	**38.30**	**32.93**

2008	Dividend Paid	Price High	Price Low
First Quarter (through January 31)	$ 0.3475	**$ 36.23**	**$ 31.43**

The number of record holders of the Company's Common Stock at January 31, 2008, was 23,882. The book value of the Company's Common Stock at January 31, 2008, was $32.71.

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, from OERI, on OERI'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

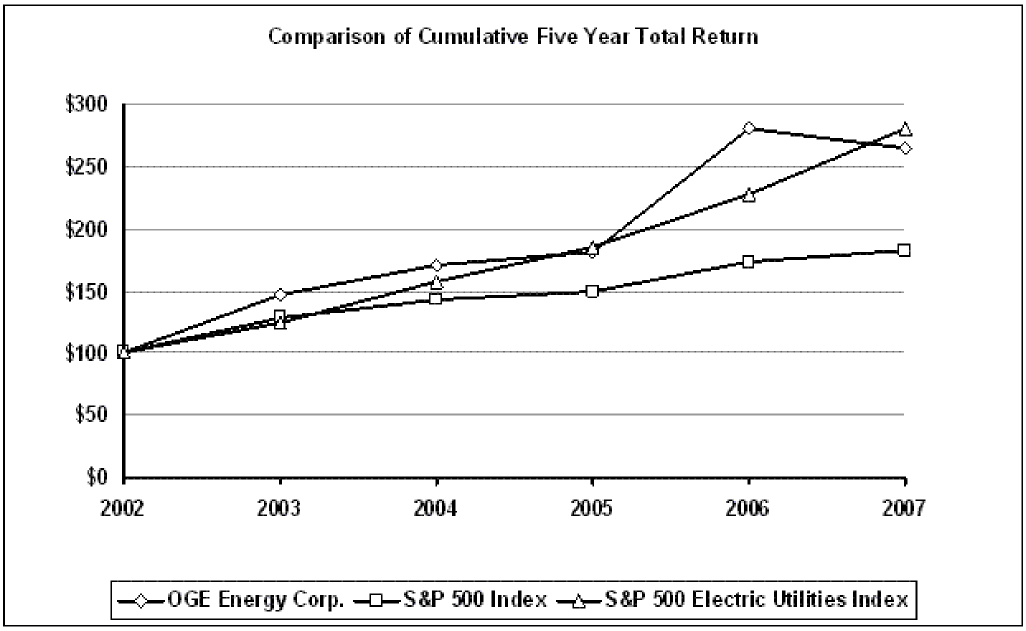
The shares indicated below represent shares of Company common stock purchased on the open market by the trustee for the Company's Stock Ownership and Retirement Savings Plan and reflect shares purchased with employee contributions as well as the portion attributable to the Company's matching contributions.

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
1/1/07 – 1/31/07	43,200	$ 38.55	N/A	N/A
2/1/07 – 2/28/07	---	$ ---	N/A	N/A
3/1/07 – 3/31/07	77,600	$ 37.77	N/A	N/A
4/1/07 – 4/30/07	69,900	$ 39.23	N/A	N/A
5/1/07 – 5/31/07	---	$ ---	N/A	N/A
6/1/07 – 6/30/07	78,900	$ 34.63	N/A	N/A
7/1/07 – 7/31/07	43,600	$ 35.37	N/A	N/A
8/1/07 – 8/31/07	45,600	$ 31.62	N/A	N/A
9/1/07 – 9/30/07	45,800	$ 32.80	N/A	N/A
10/1/07 – 10/31/07	54,100	$ 34.51	N/A	N/A
11/1/07 – 11/30/07	13,400	$ 36.38	N/A	N/A
12/1/07 – 12/31/07	---	$ ---	N/A	N/A

N/A – not applicable

Company Stock Performance

The following graph shows a five-year comparison of cumulative total returns for the Company's common stock, the S&P 500 Index and the S&P 500 Electric Utilities Index. The graph assumes that the value of the investment in the Company's common stock and each index was 100 at December 31, 2002, and that all dividends were reinvested. As of December 31, 2007, the closing price of the Company's common stock on the New York Stock Exchange was $36.29.



	2002	2003	2004	2005	2006	**2007**
OGE Energy Corp.	100	147	170	181	281	**264**
S&P 500 Index	100	129	143	150	173	**183**
S&P 500 Electric Utilities Index	100	124	157	185	228	**280**

Item 6. Selected Financial Data.

HISTORICAL DATA

Year ended December 31	**2007**	2006 (A)	2005 (B)	2004 (B)	2003 (B)
SELECTED FINANCIAL DATA					
(In millions, except per share data)					
Results of Operations Data:					
Operating revenues	**$ 3,797.6**	$ 4,005.6	$ 5,911.5	$ 4,862.6	$ 3,757.4
Cost of goods sold	**2,634.7**	2,902.5	4,942.3	3,937.7	2,841.6
Gross margin on revenues	**1,162.9**	1,103.1	969.2	924.9	915.8
Other operating expenses	**707.6**	670.4	646.8	630.4	617.9
Operating income	**455.3**	432.7	322.4	294.5	297.9
Interest income	**2.1**	6.2	3.5	4.9	1.3
Allowance for equity funds used during construction	---	4.1	---	0.9	---
Other income (loss)	**17.4**	16.3	(0.3)	10.5	2.0
Other expense	**23.7**	16.7	5.5	4.7	7.6
Interest expense	**90.2**	96.0	90.3	90.8	92.3
Income tax expense	**116.7**	120.5	68.6	73.4	70.8
Income from continuing operations	**244.2**	226.1	161.2	141.9	130.5
Income from discontinued operations, net of tax	---	36.0	49.8	11.6	4.7
Cumulative effect on prior years of change in accounting principle, net of tax of $3.4	---	---	---	---	(5.4)
Net income	**$ 244.2**	$ 262.1	$ 211.0	$ 153.5	$ 129.8
Basic earnings (loss) per average common share					
Income from continuing operations	**$ 2.66**	$ 2.48	$ 1.79	$ 1.61	$ 1.60
Income from discontinued operations, net of tax	---	0.40	0.55	0.13	0.06
Loss from cumulative effect of accounting change, net of tax	---	---	---	---	(0.07)
Net income	**$ 2.66**	$ 2.88	$ 2.34	$ 1.74	$ 1.59
Diluted earnings (loss) per average common share					
Income from continuing operations	**$ 2.64**	$ 2.45	$ 1.77	$ 1.60	$ 1.59
Income from discontinued operations, net of tax	---	0.39	0.55	0.13	0.06
Loss from cumulative effect of accounting change, net of tax	---	---	---	---	(0.07)
Net income	**$ 2.64**	$ 2.84	$ 2.32	$ 1.73	$ 1.58
Dividends declared per share	**$ 1.3675**	$ 1.3375	$ 1.33	$ 1.33	$ 1.33

(A) The Company adopted Statement of Financial Accounting Standard No. 123 (Revised), "Share-Based Payment," using the modified prospective transition method, effective January 1, 2006, which required 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.

(B) Amounts for 2005 and 2004 were restated for discontinued operations related to the sale of Enogex assets in May 2006, as discussed in Note 7 of Notes to Consolidated Financial Statements. Amounts for year 2003 have not been restated for discontinued operations since this information is not available as the Company's financial records were not maintained in a manner to provide this information for years prior to 2004.

Year ended December 31	**2007**	2006 (A)	2005 (B)	2004 (B)	2003 (B)
SELECTED FINANCIAL DATA					
(In millions, except per share data)					
Balance Sheet Data (at period end):					
Property, plant and equipment, net (C)	**$ 4,246.3**	$ 3,867.5	$ 3,567.4	$ 3,581.0	$ 3,309.5
Total assets (D)	**$ 5,237.8**	$ 4,898.4	$ 4,871.4	$ 4,787.1	$ 4,553.7
Long-term debt	**$ 1,344.6**	$ 1,346.3	$ 1,350.8	$ 1,424.1	$ 1,436.1
Total stockholders' equity	**$ 1,680.9**	$ 1,603.8	$ 1,375.7	$ 1,285.6	$ 1,201.6
CAPITALIZATION RATIOS (E)					
Stockholders' equity	**55.5%**	54.3%	50.5%	46.9%	44.7%
Long-term debt	**44.5%**	45.7%	49.5%	53.1%	55.3%
RATIO OF EARNINGS TO FIXED CHARGES (F)					
Ratio of earnings to fixed charges	**4.65**	4.28	3.37	3.23	3.08

(A) The Company adopted Statement of Financial Accounting Standard No. 123 (Revised), "Share-Based Payment," using the modified prospective transition method, effective January 1, 2006, which required 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.
(B) Amounts for 2005 and 2004 were restated for discontinued operations related to the sale of Enogex assets in May 2006, as discussed in Note 7 of Notes to Consolidated Financial Statements. Amounts for year 2003 have not been restated for discontinued operations since this information is not available as the Company's financial records were not maintained in a manner to provide this information for years prior to 2004.
(C) Includes net property, plant and equipment related to discontinued operations of approximately $166.9 million, $169.3 million and $34.9 million during the years ended December 31, 2003, 2004 and 2005, respectively.
(D) Amounts for years 2003 through 2006 have been restated to net price risk management assets and liabilities under master netting agreements in accordance with Financial Accounting Standards Board ("FASB") Interpretation ("FIN") No. 39 (As Amended), "Offsetting of Amounts Related to Certain Contracts – an interpretation of Accounting Principles Board Opinion No. 10 and FASB Statement No. 105."
(E) Capitalization ratios = [Stockholders' equity / (Stockholders' equity + Long-term debt + Long-term debt due within one year)] and [(Long-term debt + Long-term debt due within one year) / (Stockholders' equity + Long-term debt + Long-term debt due within one year)].
(F) For purposes of computing the ratio of earnings to fixed charges, (1) earnings consist of pre-tax income from continuing operations (excluding interest related to FIN 48 liabilities) plus fixed charges, less allowance for borrowed funds used during construction and other capitalized interest; and (2) fixed charges consist of interest on long-term debt (excluding interest related to FIN 48 liabilities), 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 four business segments: (i) electric utility, (ii) natural gas transportation and storage, (iii) natural gas gathering and processing and (iv) natural gas marketing.

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. OG&E 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.

Enogex Inc. and its subsidiaries ("Enogex") are a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting and storing natural gas. The vast majority of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located primarily in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex's ongoing operations are organized into two business segments: (1) natural gas transportation and storage, pursuant to which Enogex provides (a) fee-based intrastate transportation services on a firm and interruptible basis and, pursuant to Section 311 of the Natural Gas Policy Act, as amended, interstate transportation services on an interruptible basis and (b) fee-based firm and interruptible storage services to third parties at market-based rates; and (2) natural gas gathering and processing, pursuant to which Enogex provides well connect, gathering, measurement, treating, dehydration, compression and processing services to its producer customers primarily in the Arkoma and Anadarko basins, including those operating in the Granite Wash play and Atoka play in western Oklahoma and the Texas Panhandle and the Woodford Shale play in southeastern Oklahoma.

Historically, Enogex had also engaged in natural gas marketing through its subsidiary, OGE Energy Resources, Inc. ("OERI"). In connection with the proposed initial public offering of common units of OGE Enogex Partners L.P., a Delaware limited partnership (the "Partnership"), on January 1, 2008, Enogex distributed the stock of OERI to OGE Energy. Enogex's historical consolidated financial statements were prepared from Enogex's books and records related to Enogex's operating assets. Accordingly, the discussion that follows includes the results of OERI, but as of January 1, 2008, Enogex no longer has any interest in the results of OERI.

In May 2007, the Company formed the Partnership as part of its strategy to further develop Enogex's natural gas midstream assets and operations. The Partnership has filed a registration statement with the Securities and Exchange Commission for a proposed initial public offering of its common units, representing limited partner interests in the Partnership (the "Offering"). At the date of this annual report, the registration statement relating to the Offering is not effective. Prior to the closing of the Offering, Enogex Inc., which is currently an Oklahoma corporation, would convert to Enogex LLC, a Delaware limited liability company. In connection with the Offering, the Company is expected to contribute an approximately 25 percent membership interest in Enogex LLC to a wholly owned subsidiary of the Partnership that would serve as Enogex LLC's managing member and would control its assets and operations. A wholly owned subsidiary of the Company will retain the remaining approximately 75 percent membership interest in Enogex LLC. It is currently contemplated that at the completion of the Offering, the Company will indirectly own an approximate 68 percent limited partner interest and a two percent general partner interest in the Partnership.

The completion of the Offering is subject to numerous conditions and no assurances can be made that it will be successfully completed. The Company expects to continue to evaluate strategic alternatives for Enogex, including other transactions that the Company believes could provide long-term value to its shareowners and the proposed initial public offering. The securities offered under the registration statement may not be sold, nor may offers to buy be accepted, prior to the time that the registration statement becomes effective. The information contained in this annual report with respect to the Offering shall not constitute an offer to sell or a solicitation of an offer to buy any securities.

From a financial reporting perspective, the formation of the Partnership had no effect on the Company's financial statements as of and for the periods ended December 31, 2007, 2006 and 2005. In the event that, and beginning with the period in which, the Offering is completed, the Company will consolidate the results of the Partnership with minority interest treatment for the common units of the Partnership owned by unitholders other than the Company or its consolidated subsidiaries.

Executive Overview

Strategy

The Company's vision is to fulfill its critical role in the nation's electric utility and natural gas midstream pipeline infrastructure and meet individual customers' needs for energy and related services in a safe, reliable and efficient manner. The Company intends to execute its vision by focusing on its regulated electric utility business and unregulated midstream gas business. 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, maintenance of a dividend payout ratio consistent with its peer group and maintenance of strong credit ratings. The Company believes it can accomplish these financial goals by, among other things, pursuing multiple avenues to build its business, maintaining a diversified asset position, continuing to develop a wide range of skills to succeed with changes in its industries, providing products and services to customers efficiently, managing risks effectively and maintaining strong regulatory and legislative relationships.

OG&E has been focused on increased investment at the utility to improve reliability and meet load growth, replace infrastructure equipment, replace aging transmission and distribution systems, provide new products and services and deploy newer technology that improves operational, financial and environmental performance. As part of this plan, OG&E has taken, or has committed to take, the following actions:

- 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;
- OG&E entered into an agreement in February 2006 to engineer, procure and construct a wind generation energy system for a 120 MW wind farm ("Centennial") in northwestern Oklahoma. The wind farm was fully in service in January 2007;
- OG&E announced in early 2007a six-year construction initiative that is estimated to include up to $2.4 billion in major projects designed to expand capacity, enhance reliability and improve environmental performance. OG&E's six-year construction initiative also includes strengthening and expanding the electric transmission, distribution and substation systems and replacing aging infrastructure;
- OG&E announced in October 2007 its goal to increase its wind power generation over the next four years from its current 170 MWs to 770 MWs, and as part of this plan, OG&E expects to issue a request for proposal in the first quarter of 2008;
- OG&E announced its desire to begin building a high-capacity transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma in early to mid-2008 and then eventually to extend the line from Woodward to Guymon, Oklahoma in the Oklahoma Panhandle that would be used by OG&E and others to deliver wind-generated power from western and northwestern Oklahoma to the rest of Oklahoma and other states;
- OG&E has also previously committed to the Southwest Power Pool ("SPP") to build the Oklahoma portion of the western half of the SPP "X-Plan" that includes transmission lines from Woodward to Tuco, Texas and from Woodward to Spearville, Kansas;
- OG&E entered into agreements in January 2008 to purchase a 51 percent ownership interest in the 1,230 MW Redbud power plant; and
- With the previously announced six-year construction initiative discussed above, and including the acquisition of the Redbud power plant, OG&E's 2008 to 2013 capital expenditures are expected to be approximately $3.0 billion.

The increase in wind power generation, the building of the transmission lines and the acquisition of the Redbud power plant are all subject to numerous regulatory and other approvals, including appropriate regulatory treatment from the OCC and, in the case of the transmission lines, the SPP. Other projects involve installing new emission-control and monitoring equipment at existing OG&E power plants to help meet OG&E's commitment to comply with current and future environmental requirements. For additional information regarding the above items and other regulatory matters, see Note 17 of Notes to Consolidated Financial Statements.

Results of operations from the transportation and storage business are determined primarily by the volumes of natural gas transported on Enogex's intrastate pipeline system, volumes of natural gas stored at Enogex's storage facilities and the level of fees charged to Enogex's customers for such services. Enogex generates a majority of its revenues and margins for its pipeline business under fee-based transportation contracts that are directly related to the volume of natural gas capacity reserved on its system. The margin Enogex earns from its transportation activities is not directly dependent on commodity prices. To the extent a sustained decline in commodity prices results in a decline in volumes, Enogex's revenues from these arrangements would be reduced. Results of operations from the gathering and processing business are determined primarily by the volumes of natural gas Enogex gathers and processes, its current contract portfolio and natural gas and natural gas liquids ("NGL") prices. Because of the natural decline in production from existing wells connected to Enogex's systems, Enogex's success depends on its ability to gather new sources of natural gas, which depends on certain factors beyond its or our control. Any decrease in supplies of natural gas could adversely affect Enogex's gathering and processing business. As a result, Enogex's cash flows associated with these wells will also decline over time. To maintain or increase throughput levels on its gathering systems and the asset utilization rates at its natural gas processing plants, Enogex must continually obtain new natural gas supplies. The primary factors affecting Enogex's ability to obtain new supplies of natural gas and attract new customers to its assets depends in part on the level of successful drilling activity near these systems, Enogex's ability to compete for volumes from successful new wells and Enogex's ability to expand capacity as needed.

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, capturing growth opportunities through expansion projects and increased utilization of existing assets and strategic acquisitions. 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. Over the past several years, Enogex has initiated multiple organic growth projects. Currently, Enogex's organic growth capital expenditures are focused on three primary areas:

- upgrades to Enogex's existing transportation system due to increased volumes as a result of the broader shift of gas flow from the Rocky Mountains and the mid-continent to markets in the northeast and southeast United States;

- expansions on the east side of Enogex's gathering system, primarily in the Woodford Shale play in southeastern Oklahoma through the construction of new facilities and expansion of existing facilities and its interest in the joint venture, Atoka Midstream LLC; and
- expansions on the west side of Enogex's gathering system, primarily in the Granite Wash play and Atoka play in the Wheeler County, Texas area, which is located in the Texas Panhandle.

For additional information regarding current or recently completed projects, see Note 16 of Notes to Consolidated Financial Statements.

In addition to focusing on growing its earnings, Enogex has reduced its exposure to changes in commodity prices and minimized its exposure to keep-whole processing arrangements. Enogex's profitability increased significantly from 2003 to 2007 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, while at the same time decreasing the volatility associated with commodity prices.

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 continue to focus on those products and services with limited or manageable commodity exposure. Also, the Company believes that many of the risk management practices, commercial skills and market information available from OERI provide value to all of the Company's businesses.

Summary of Operating Results

2007 compared to 2006. The Company reported net income of approximately $244.2 million, or $2.64 per diluted share, in 2007 as compared to approximately $262.1 million, or $2.84 per diluted share, in 2006. The decrease in net income of approximately $17.9 million, or $0.20 per diluted share, during 2007 as compared to 2006 was primarily due to:

- an increase in net income at OG&E of approximately $12.4 million, or $0.13 per diluted share of the Company's common stock, in 2007 as compared to 2006 primarily due to a higher gross margin from higher rates from the Centennial wind farm rider, security rider and Arkansas rate case, increased peak demand and related revenues by non-residential customers in OG&E's service territory and new customer growth in OG&E's service territory partially offset by cooler weather in OG&E's service territory. Also contributing to the increase in net income was lower interest expense and lower income tax expense partially offset by higher depreciation expense;
- a decrease in net income at Enogex (including discontinued operations) of approximately $27.3 million, or $0.30 per diluted share of the Company's common stock, in 2007 as compared to 2006, of which $0.39 per diluted share was due to a reduction in earnings associated with discontinued operations. This decrease was partially offset by an increase of approximately $0.09 per diluted share associated with continuing operations primarily due to higher gross margins in each of Enogex's segments partially offset by higher operation and maintenance expenses, lower other income and higher income tax expense; and
- a net loss at OGE Energy of approximately $3.7 million, or $0.04 per diluted share of the Company's common stock, in 2007, as compared to a net loss of approximately $0.7 million, or $ 0.01 per diluted share, in 2006 primarily due to an income tax adjustment recorded in 2006.

Enogex's net income for 2007 was approximately $86.2 million, which included OERI's recorded losses of approximately $2.2 million resulting from recording natural gas storage inventory at the lower of cost or market value. The offsetting gains from the sale of withdrawals from inventory are expected to be realized during the first quarter of 2008.

2006 compared to 2005. The Company reported net income of approximately $262.1 million, or $2.84 per diluted share, in 2006 as compared to approximately $211.0 million, or $2.32 per diluted share, in 2005. The increase in net income of approximately $51.1 million, or $0.52 per diluted share, during 2006 as compared to 2005 was primarily due to:

- an increase in net income at OG&E of approximately $19.6 million, or $0.19 per diluted share of the Company's common stock, in 2006 as compared to 2005 primarily due to a higher gross margin from a price variance primarily due to rate increases and new customer growth and increased usage in OG&E's service territory. These increases were partially offset by higher operation and maintenance expenses, higher interest expense and higher income tax expense;

- an increase in net income at Enogex (including discontinued operations) of approximately $23.7 million, or $0.24 per diluted share of the Company's common stock, in 2006 as compared to 2005 primarily due to higher gross margins in each of Enogex's segments which was partially offset by higher other operation and maintenance expense and higher income tax expense and a reduction of $0.16 per diluted share attributable to discontinued operations; and
- a net loss at OGE Energy of approximately $0.7 million, or $0.01 per diluted share of the Company's common stock, in 2006 as compared to a net loss of approximately $8.5 million, or $0.10 per diluted share, in 2005 primarily due to higher income tax benefits in 2006 as a result of recording the Employee Stock Ownership Plan ("ESOP") dividend deduction at OGE Energy in 2006 which was previously recorded at OG&E in 2005.

Enogex's net income for 2006 was approximately $113.5 million, which included OERI's recorded losses of approximately $6.3 million resulting from recording natural gas storage inventory at the lower of cost or market value. The offsetting gains from the sale of withdrawals from inventory were realized during the first quarter of 2007.

OERI's results of operations are included in the historical financial and operating data rather than in discontinued operations because subsequent to the distribution of the stock of OERI to OGE Energy it is anticipated that the ongoing transactions between OERI and Enogex will constitute a significant continuation of activities and cash flows for Enogex.

Recent Developments and Regulatory Matters

Proposed Acquisition of Power Plant

On January 21, 2008, OG&E entered into a Purchase and Sale Agreement ("Purchase and Sale Agreement") with Redbud Energy I, LLC, Redbud Energy II, LLC and Redbud Energy III, LLC ("Redbud Sellers"), which are indirectly owned by Kelson Holdings LLC, a subsidiary of Harbinger Capital Partners Master Fund I, Ltd. and Harbinger Capital Partners Special Situations Fund, L.P. Pursuant to the Purchase and Sale Agreement, OG&E agreed to acquire from the Redbud Sellers the entire partnership interest in Redbud Energy LP which currently owns a 1,230 MW natural gas-fired, combined-cycle power generation facility in Luther, Oklahoma ("Redbud Facility"), for approximately $852 million, subject to working capital and inventory adjustments in accordance with the terms of the Purchase and Sale Agreement.

In connection with the Purchase and Sale Agreement, OG&E also entered into (i) an Asset Purchase Agreement ("Asset Purchase Agreement") with the Oklahoma Municipal Power Authority ("OMPA") and the Grand River Dam Authority ("GRDA"), pursuant to which OG&E agreed that it would, after the closing of the transaction contemplated by the Purchase and Sale Agreement, dissolve Redbud Energy LP and sell a 13 percent undivided interest in the Redbud Facility to the OMPA and sell a 36 percent undivided interest in the Redbud Facility to the GRDA, and (ii) an Ownership and Operating Agreement ("Ownership and Operating Agreement") with the OMPA and the GRDA, pursuant to which OG&E, the OMPA and the GRDA, following the completion of the transaction contemplated by the Asset Purchase Agreement, would jointly own the Redbud Facility and OG&E will act as the operations manager and perform the day-to-day operation and maintenance of the Redbud Facility. Under the Ownership and Operating Agreement, each of the parties would be entitled to its pro rata share, which is equal to its respective ownership interest, of all output of the Redbud Facility and would pay its pro rata share of all costs of operating and maintaining the Redbud Facility, including its pro rata share of the operations manager's general and administrative overhead allocated to the Redbud Facility.

The transactions described above are subject to the expiration or termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act, an order from the FERC authorizing the contemplated transactions, an order from the OCC approving the prudence of the transactions and an appropriate reasonable recovery mechanism, and other customary conditions. OG&E will not be obligated to complete the transactions if the orders from the FERC and the OCC contain any conditions or restrictions which are materially more burdensome than those proposed in OG&E's applications. Either OG&E or the Redbud Sellers may terminate the Purchase and Sale Agreement if the closing has not occurred on or prior to November 16, 2008; provided that the Redbud Sellers have the option to extend such deadline for up to an additional 180 days if the sole reason the closing has not occurred is because the governmental and regulatory approvals have not been obtained. There can be no assurances that the transactions will be completed or as to its ultimate timing. OG&E expects to file an application with the OCC in March 2008 asking the OCC to approve the prudency of the transactions and an appropriate reasonable recovery mechanism. The OCC rules provide that the OCC has up to 240 days to issue an order determining OG&E's pre-approval request. Absent a settlement, the earliest OG&E expects an order from the OCC is November 2008.

Cancelled Red Rock Power Plant

On October 11, 2007, the OCC issued an order denying OG&E and Public Service Company of Oklahoma's ("PSO") request for pre-approval of their proposed 950 MW Red Rock power plant project. The plant, which was to be built at OG&E's Sooner plant site, was to be 42 percent owned by OG&E, 50 percent owned by PSO and eight percent owned by the OMPA. As a result, on October 11, 2007, OG&E, PSO and the OMPA agreed to terminate agreements to build and operate the plant. At December 31, 2007, OG&E had incurred approximately $17.5 million of capitalized costs associated with the Red Rock power plant project. In December 2007, OG&E filed an application with the OCC requesting authorization to defer, and establish a method for recovery of, approximately $14.7 million of, Oklahoma jurisdictional costs associated with the Red Rock power plant project that are currently reflected in Deferred Charges and Other Assets on the Company's Consolidated Balance Sheets. If the request for deferral is not approved, the deferred costs will be expensed. In February 2008, the OCC issued a procedural schedule with a hearing scheduled for May 7, 2008. OG&E expects to receive an order from the OCC in this matter by the end of 2008.

OCC Order Confirming Savings / Acquisition of McClain Power Plant

The 2002 agreed-upon settlement of an OG&E rate case ("2002 Settlement Agreement") required that, if OG&E did not acquire electric generation of not less than 400 MW ("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. On July 9, 2004, OG&E completed the acquisition of the McClain Plant that was intended to satisfy the requirement in the 2002 Settlement Agreement to acquire New Generation. On June 7, 2007, OG&E filed an application with the OCC supporting its compliance with the 2002 Settlement Agreement. On November 21, 2007, OG&E received an order from the OCC affirming that the acquisition of the McClain Plant provided savings to OG&E's Oklahoma customers in excess of the required $75 million over the three-year period from January 1, 2004 through December 31, 2006.

Pipeline Lease Project

In December 2006, Enogex entered into a firm capacity lease agreement with Midcontinent Express Pipeline, LLC ("MEP") for a primary term of 10 years (subject to possible extension) that would give MEP and its shippers access to capacity on Enogex's system. The quantity of capacity subject to the MEP lease agreement is currently 275 million cubic feet per day ("MMcf/d") with the quantity ultimately to be leased subject to being increased by mutual agreement pursuant to the lease agreement. In addition to MEP's lease of Enogex's capacity, the proposed MEP project includes construction by MEP of a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. Pending necessary regulatory approval, the MEP project is currently expected to be in service during the first quarter of 2009. Enogex currently estimates that its capital expenditures related to this project will be approximately $86 million. The lease agreement with MEP is subject to certain contingencies, including regulatory approval. Prior to that approval, Enogex may incur expenditures of between approximately $20 million and $40 million primarily related to commitments for materials that can be sold or used in normal operations in the event the MEP project does not proceed. The amount not recovered or utilized for such expenditures is not expected to be material.

MEP filed an application with the FERC on October 9, 2007 requesting a certificate of public convenience and necessity authorizing MEP to construct its pipeline and lease certain capacity from Enogex. On October 9, 2007, Enogex also filed an application with the FERC for issuance of a limited jurisdiction certificate authorizing its lease agreement with MEP. Certain Enogex shippers have filed motions to intervene in Enogex's FERC certificate proceeding, and some have protested Enogex's certificate application. Protestors have claimed that it is unduly discriminatory for Enogex to propose to lease capacity to MEP while not generally offering firm interstate transportation service, that the lease arrangement will adversely affect the availability of interruptible interstate transportation service on the Enogex system and that the lease payment specified under the MEP lease agreement is unduly preferential in MEP's favor. These protestors have urged the FERC to reject the MEP lease arrangement or to condition its acceptance on a requirement that Enogex offer existing shippers taking interruptible interstate service the opportunity to convert that service to firm service. One protestor has asked the FERC to consolidate the Enogex certificate proceeding with Enogex's Section 311 triennial rate proceeding currently pending before the FERC. While Enogex cannot predict what action the FERC may take regarding the lease agreement, Enogex believes that the proposed MEP lease arrangement is consistent with FERC policy and precedent involving similar lease arrangements.

On January 18, 2008, Enogex filed a 30-day advance notice to advise the FERC of its intended construction of the Bennington Station Facilities. In that notice, Enogex described the environmental impacts likely to be associated with construction and operation of a new 24,000 horsepower transmission compressor station and associated pipeline that Enogex proposes to construct to support its provision of pipeline capacity under its capacity leases including the lease with MEP. Enogex believes that it has complied with all applicable requirements of the FERC's regulations pertaining to an intrastate pipeline's construction of facilities under Section 311 of the Natural Gas Policy Act, as amended. The FERC did not take any action with respect to Enogex's advance notice filing and Enogex has begun construction of the Bennington Station Facilities.

Southeastern Oklahoma / East Side Expansions

Enogex is expanding in the Woodford Shale play and has several projects either completed or scheduled for completion in 2007 and 2008. For example, in December 2006, Enogex entered into a joint venture arrangement with Pablo Gathering, LLC, a subsidiary of Pablo Energy II, LLC, a Texas-based exploration and production company. The joint venture, Atoka Midstream LLC, constructed, owns and/or operates a gathering system and processing plant and related facilities relating to production in certain areas in southeastern Oklahoma. The gathering system and processing plant were placed in service during the third quarter of 2007. Enogex owns a 50 percent membership interest in Atoka Midstream and acts as the managing member and operator of the facilities owned by the joint venture.

Texas Panhandle / West Side Expansions

In August 2006, Enogex completed a project to expand its gathering pipeline capacity in the Granite Wash play and Atoka play in the Wheeler County, Texas area of the Texas Panhandle that has allowed Enogex to benefit from growth opportunities in that marketplace. This project included the addition of a 20-inch gathering header that is intended to be used to collect gas from producers and deliver the gas to multiple outlets and processing plants.

In February 2008, Enogex completed construction on the first phase (22 miles) of a new 30-mile pipeline project that will connect Enogex's Hughes, Coal and Pittsburgh county gathering system with the 30-inch Enogex mainline pipeline to Bennington, Oklahoma, and the 24-inch Enogex mainline pipeline to Wilburton, Oklahoma. The gathering project created additional gathering capacity of 125 MMcf/d for customers desiring low-pressure services with the potential to double this amount with incremental compression investments. The pipeline is complemented by approximately 20,000 horsepower of compression providing reliable gathering and take-away capacity for its Woodford Shale customers, who now have access to 350 MMcf/d to 500 MMcf/d of existing take-away capacity on Enogex's mainline pipeline. Also, Enogex recently committed to approximately $50 million in additional expansions in this area primarily during 2008 and 2009 and expects its latest expansion project to be in service by the third quarter of 2008.

Enogex continues to review growth opportunities to expand this project and has recently begun several additional new projects to continue expansion on the west side of its system. In addition, Enogex has installed approximately 11.5 miles of 12-inch pipeline and added approximately 5,400 horsepower of compression to its Billy Rose compressor station.

2008 Outlook

The Company's earnings guidance for 2008 is between $223 million and $242 million of net income or $2.40 to $2.60 per diluted share assuming approximately 93.1 million average diluted shares outstanding, cash flow from operations of between $483 million and $502 million and an effective tax rate of 33.5 percent.

(In millions, except per share data)	Dollars	Diluted EPS
OG&E	$145 - $155	$1.56 - $1.66
Enogex	$83 - $91	$0.89 - $0.98
Holding Company	($5) - ($4)	($0.05) - ($0.04)
Total	$223 - $242	$2.40 - $2.60

Key assumptions for 2008 are:

OG&E

As shown above, OG&E's earnings guidance for 2008 is between $145 million to $155 million, or $1.56 to $1.66 per diluted share of the Company's common stock. Key factors and assumptions underlying this guidance include:

- Normal weather patterns are experienced for the remainder of the year;
- Gross margin on weather-adjusted, retail electric sales increases approximately two percent;
- Operating expenses of approximately $536 million;
- Interest costs of approximately $77 million;

- An effective tax rate of approximately 31.1 percent; and
- Capital expenditures for investment in OG&E's generation, transmission and distribution system of approximately $789 million in 2008, which includes capital expenditures in the amount of approximately $435 million associated with OG&E's planned acquisition of the Redbud generating plant.

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

As shown above, Enogex's earnings guidance is $83 million to $91 million, or $0.89 to $0.98 per diluted share of the Company's common stock. Key factors and assumptions underlying this guidance include:

- Total Enogex anticipated gross margin of approximately $376 million to $390 million. The 2008 guidance assumes:
  - Transportation and storage gross margin contribution of approximately $141 million.
  - Gathering and processing gross margin contribution of approximately $235 million to $249 million. Key factors affecting the gathering and processing gross margin forecast are:
    - Assumed increase of eight percent in gathered volumes over 2007;
    - Assumed natural gas prices of $7.25 to $7.64 per Million British thermal unit ("MMBtu") in 2008;
    - Assumed realized commodity spreads of $5.48 to $6.09 per MMBtu in 2008. The realized commodity spread takes into account that 59 percent of processing volumes that bear price risk are hedged;
    - Assumed weighted average natural gas liquids prices of $1.20 to $1.27 per gallon in 2008;
- Operating expenses of approximately $201 million;
- Interest expense of approximately $30 million in 2008; and
- Capital expenditures for investment in Enogex's pipeline system of approximately $292 million in 2008.

Holding Company

As shown above, the projected loss at the holding company is between $4 million and $5 million, or $0.04 to $0.05 per diluted share, primarily due to interest expense relating to long and short-term debt borrowings.

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 no more than 65 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. At the Company's November 2007 Board meeting, management, after considering estimates of future earnings and numerous other factors, recommended to the Board of Directors an increase in the current quarterly dividend rate to $0.3475 per share from $0.34 per share effective with the Company's first quarter 2008 dividend.

Results of Operations

The following discussion and analysis presents factors that affected the Company's consolidated results of operations for the years ended December 31, 2007, 2006 and 2005 and the Company's consolidated financial position at December 31, 2007 and 2006. 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.

Year ended December 31 *(In millions, except per share data)*	**2007**	2006	2005
Operating income	**$ 455.3**	$ 432.7	$ 322.4
Net income	**$ 244.2**	$ 262.1	$ 211.0
Basic average common shares outstanding	**91.7**	91.0	90.3
Diluted average common shares outstanding	**92.5**	92.1	90.8
Basic earnings per average common share	**$ 2.66**	$ 2.88	$ 2.34
Diluted earnings per average common share	**$ 2.64**	$ 2.84	$ 2.32
Dividends declared per share	**$ 1.3675**	$ 1.3375	$ 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 the cost of capital and income taxes.

Operating Income (Loss) by Business Segment

Year ended December 31 *(In millions)*	**2007**	2006	2005
OG&E (Electric Utility)	**$ 292.0**	$ 293.9	$ 232.2
Enogex (Natural Gas Pipeline)			
Transportation and storage	**55.0**	54.7	37.3
Gathering and processing	**91.4**	79.8	58.5
Marketing	**17.1**	4.3	(6.2)
Other Operations (A)	**(0.2)**	---	0.6
Consolidated operating income	**$ 455.3**	$ 432.7	$ 322.4

(A) Other Operations primarily includes consolidating eliminations.

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

Year ended December 31 *(Dollars in millions)*	**2007**	2006	2005
Operating revenues	**$ 1,835.1**	$ 1,745.7	$ 1,720.7
Cost of goods sold	**1,025.1**	950.0	994.2
Gross margin on revenues	**810.0**	795.7	726.5
Other operation and maintenance	**320.7**	316.5	309.2
Depreciation	**141.3**	132.2	134.4
Taxes other than income	**56.0**	53.1	50.7
Operating income	**292.0**	293.9	232.2
Interest income	**---**	1.9	2.6
Allowance for equity funds used during construction	**---**	4.1	---
Other income (loss)	**5.0**	4.0	(2.8)
Other expense	**7.2**	9.7	2.5
Interest expense	**54.9**	60.1	47.2
Income tax expense	**73.2**	84.8	52.6
Net income	**$ 161.7**	$ 149.3	$ 129.7
Operating revenues by classification			
Residential	**$ 706.4**	$ 698.8	$ 663.6
Commercial	**450.1**	428.3	418.9
Industrial	**221.4**	215.7	220.8
Oilfield	**140.9**	129.3	134.8
Street light	**9.1**	11.4	12.2
Public authorities	**172.3**	159.6	160.9
Sales for resale	**68.8**	65.4	67.7
Provision for rate refund	**0.1**	(0.9)	(2.0)
System sales revenues	**1,769.1**	1,707.6	1,676.9
Off-system sales revenues	**35.1**	2.7	4.9
Other	**30.9**	35.4	38.9
Total operating revenues	**$ 1,835.1**	$ 1,745.7	$ 1,720.7
MWH (A) sales by classification *(in millions)*			
Residential	**8.7**	8.7	8.5
Commercial	**6.3**	6.2	6.0
Industrial	**4.2**	4.4	4.5
Oilfield	**2.8**	2.7	2.6
Street light	**0.1**	0.1	0.1
Public authorities	**2.9**	2.8	2.8
Sales for resale	**1.4**	1.5	1.5
System sales	**26.4**	26.4	26.0
Off-system sales	**0.7**	---	0.1
Total sales	**27.1**	26.4	26.1
Number of customers	**762,234**	754,840	745,493
Average cost of energy per KWH (B) - cents			
Natural gas	**6.872**	6.829	8.378
Coal	**1.143**	1.114	1.004
Total fuel	**3.173**	3.003	3.234
Total fuel and purchased power	**3.523**	3.366	3.557
Degree days (C)			
Heating - Actual	**3,175**	2,746	3,159
Heating - Normal	**3,631**	3,631	3,631
Cooling - Actual	**2,221**	2,485	2,163
Cooling - 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.

2007 compared to 2006. OG&E's operating income decreased approximately $1.9 million, or 0.7 percent, in 2007 as compared to 2006 primarily due to higher depreciation expense, higher taxes other than income and higher operation and maintenance expenses partially offset by a higher gross margin.

Gross Margin

Gross margin was approximately $810.0 million in 2007 as compared to approximately $795.7 million in 2006, an increase of approximately $14.3 million, or 1.8 percent. The gross margin increased primarily due to:

- higher rates from the Centennial wind farm rider, security rider and Arkansas rate case, which increased the gross margin by approximately $25.1 million;
- increased peak demand and related revenues by non-residential customers in OG&E's service territory, which increased the gross margin by approximately $9.4 million; and
- new customer growth in OG&E's service territory, which increased the gross margin by approximately $9.1 million.

These increases in the gross margin were partially offset by:

- cooler weather in OG&E's service territory resulting in an approximate 11 percent decrease in cooling degree days compared to 2006, which decreased the gross margin by approximately $16.3 million; and
- price variance due to sales and customer mix, which decreased the gross margin by approximately $13.6 million.

Cost of goods sold for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was approximately $756.1 million in 2007 as compared to approximately $730.3 million in 2006, an increase of approximately $25.8 million, or 3.5 percent, primarily due to increased natural gas generation in 2007 and a gain recognized from the sale of sulfur dioxide allowances of approximately $8.9 million in 2006. 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 2007, OG&E's fuel mix was 62 percent coal, 36 percent natural gas and two percent wind. In 2006, OG&E's fuel mix was 67 percent coal and 33 percent natural gas. Purchased power costs were approximately $268.6 million in 2007 as compared to approximately $219.7 million in 2006, an increase of approximately $48.9 million, or 22.3 percent. This increase was primarily due to OG&E's entrance into the energy imbalance service market on February 1, 2007 (see Note 17 of Notes to Consolidated Financial Statements for a further discussion).

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.

Operating Income

Other operation and maintenance expenses were approximately $320.7 million in 2007 as compared to approximately $316.5 million in 2006, an increase of approximately $4.2 million, or 1.3 percent. The increase in other operation and maintenance expenses was primarily due to:

- an increase in outside services expense of approximately $12.9 million primarily due to planned overhaul expenses at the power plants;
- higher salaries, wages and other employee benefits expense of approximately $6.7 million; and
- an increase in fees and permits expense of approximately $2.2 million due to additional fees to the SPP.

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

- an increase of capitalized work of approximately $17.7 million primarily related to storm costs that were deferred as a regulatory asset in 2007; and
- a decrease of approximately $2.2 million of an additional accrual due to a settlement of a claim in 2006.

Depreciation expense was approximately $141.3 million in 2007 as compared to approximately $132.2 million in 2006, an increase of approximately $9.1 million, or 6.9 percent, primarily due to the Centennial wind farm being placed in service during January 2007.

Taxes other than income were approximately $56.0 million in 2007 as compared to approximately $53.1 million in 2006, an increase of approximately $2.9 million, or 5.5 percent, primarily due to increased ad valorem tax accruals and increased payroll tax expenses.

Additional Information

Interest Income. There was no interest income in 2007 as compared to approximately $1.9 million in 2006. The decrease was primarily due to interest income earned on fuel under recoveries in 2006 while there was a fuel over recovery balance in 2007.

Allowance for Equity Funds Used During Construction. There was no allowance for equity funds used during construction in 2007 as compared to approximately $4.1 million in 2006, a decrease of approximately $4.1 million primarily due to construction costs for the Centennial wind farm that exceeded the average daily short-term borrowings in 2006.

Other Income. Other income includes, among other things, contract work performed, non-operating rental income and miscellaneous non-operating income. Other income was approximately $5.0 million in 2007 as compared to approximately $4.0 million in 2006, an increase of approximately $1.0 million or 25.0 percent. The increase in other income was primarily due to an increase of approximately $3.6 million related to the guaranteed flat bill tariff resulting from more customers participating in this plan, along with milder weather in 2007. This was partially offset by a decrease of approximately $2.6 million associated with the tax gross up of allowance for equity funds used during construction in 2006 with no comparable item recorded in 2007.

Other Expense. Other expense includes, among other things, expenses from losses on the sale and retirement of assets, miscellaneous charitable donations, expenditures for certain civic, political and related activities and miscellaneous deductions and expenses. Other expense was approximately $7.2 million in 2007 as compared to approximately $9.7 million in 2006, a decrease of approximately $2.5 million, or 25.8 percent, primarily due to a loss on the retirement of fixed assets of approximately $5.2 million in 2006 partially offset by the write-off of non-recoverable Red Rock expenses of approximately $3.1 million for Arkansas and the FERC jurisdictions in 2007.

Interest Expense. Interest expense was approximately $54.9 million in 2007 as compared to $60.1 million in 2006, a decrease of approximately $5.2 million, or 8.7 percent. The decrease in interest expense was primarily due to:

- a settlement with the Internal Revenue Service ("IRS") resulting in a reversal of interest expense of approximately $7.2 million in 2007; and
- a decrease of approximately $7.0 million associated with the interest from a water storage facility in 2006.

These decreases in interest expense were partially offset by:

- an increase of approximately $3.5 million in interest to OGE Energy;
- an increase of approximately $1.7 million associated with the carrying charges in the over recovery on fuel from customers; and
- an increase of approximately $1.7 million due to interest expense recorded on treasury lock agreements OG&E entered into related to the issuance of long-term debt by OG&E in January 2008.

Income Tax Expense. Income tax expense was approximately $73.2 million in 2007 as compared to approximately $84.8 million in 2006, a decrease of approximately $11.6 million, or 13.7 percent, primarily due to renewable energy tax credits for which OG&E became eligible in 2007 on the wind power production from OG&E's Centennial wind farm partially offset by higher pre-tax income for OG&E.

2006 compared to 2005. OG&E's operating income increased approximately $61.7 million, or 26.7 percent, in 2006 as compared to 2005 primarily due to higher gross margins partially offset by higher operating expenses.

Gross Margin

Gross margin was approximately $795.7 million in 2006 as compared to approximately $726.5 million in 2005, an increase of approximately $69.2 million, or 9.5 percent. The gross margin increased primarily due to:

- price variance primarily due to rate increases authorized in the OCC order in December 2005, which increased the gross margin by approximately $47.6 million;

- new customer growth in OG&E's service territory, which increased the gross margin by approximately $10.9 million;
- increased peak demand and related revenues by non-residential customers in OG&E's service territory, which increased the gross margin by approximately $6.7 million; and
- warmer weather in OG&E's service territory, which increased the gross margin by approximately $6.2 million.

Fuel expense was approximately $730.3 million in 2006 as compared to approximately $795.4 million in 2005, a decrease of approximately $65.1 million, or 8.2 percent, due to lower natural gas prices. 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 2006 and 2005, respectively, OG&E's fuel mix was 67 percent coal and 33 percent natural gas and 70 percent coal and 30 percent natural gas. Though OG&E has a higher installed capability of generation from natural gas units of 57 percent, it has been more economical to generate electricity for our customers with lower priced coal. Purchased power costs were approximately $219.7 million in 2006 as compared to approximately $198.8 million in 2005, an increase of approximately $20.9 million, or 10.5 percent. This increase was primarily due to a power purchase contract that allowed OG&E to make economic purchases during peak demand summer months.

Operating Income

Other operation and maintenance expenses were approximately $316.5 million in 2006 as compared to approximately $309.2 million in 2005, an increase of approximately $7.3 million, or 2.4 percent. The increase in other operation and maintenance expenses was primarily due to:

- higher salaries, wages and other employee benefits of approximately $12.5 million;
- higher allocations from OGE Energy of approximately $3.9 million primarily due to an increase in incentive compensation;
- higher bad debt expense of approximately $3.5 million; and
- an additional accrual of approximately $2.2 million for the settlement of a claim.

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

- a decrease in outside services expense of approximately $9.3 million; and
- an increase in capitalized work of approximately $6.4 million primarily due to increased labor and transportation expenses related to more capital projects in 2006.

The other operation and maintenance expense variance includes other operation and maintenance expenses associated with the acquisition of the McClain Plant, which expenses ceased being recorded as a regulatory asset on July 8, 2005.

Depreciation expense was approximately $132.2 million in 2006 as compared to approximately $134.4 million in 2005, a decrease of approximately $2.2 million, or 1.6 percent. The decrease in depreciation expense was primarily due to:

- a decrease in depreciation rates that was implemented January 1, 2006 as approved by the OCC in December 2005; and
- a decrease due to the retirement of assets at June 30, 2006 related to a power supply contract with a large industrial customer that expired June 1, 2006.

These decreases in depreciation expense were partially offset by a full year of depreciation expense in 2006 associated with the acquisition of the McClain Plant.

Taxes other than income were approximately $53.1 million in 2006 as compared to approximately $50.7 million in 2005, an increase of approximately $2.4 million, or 4.7 percent, primarily due to increased ad valorem taxes. This variance includes ad valorem taxes associated with the acquisition of the McClain Plant, which expenses ceased being recorded as a regulatory asset on July 8, 2005.

Additional Information

Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction was approximately $4.1 million in 2006 due to construction costs associated with OG&E's Centennial wind farm that exceeded the average daily short-term borrowings in 2006. There was no allowance for equity funds used during construction in 2005.

Other Income (Loss). Other income was approximately $4.0 million in 2006 as compared to a loss of approximately $2.8 million in 2005, an increase of approximately $6.8 million. The increase in other income was primarily due to:

- a gain of approximately $3.5 million from the sale of miscellaneous assets that were recorded in 2004 and were reclassified to a regulatory liability in 2005; and
- the benefit associated with the tax gross-up of approximately $4.1 million of allowance for equity funds used during construction.

Other Expense. Other expense was approximately $9.7 million in 2006 as compared to approximately $2.5 million in 2005, an increase of approximately $7.2 million primarily due to a loss on the retirement of fixed assets in 2006.

Interest Expense. Interest expense was approximately $60.1 million in 2006 as compared to approximately $47.2 million in 2005, an increase of approximately $12.9 million, or 27.3 percent. The increase in interest expense was primarily due to:

- increased interest of approximately $7.7 million due to the one-time recognition of interest expense associated with a water storage agreement;
- increased interest of approximately $4.8 million on debt associated with the McClain Plant acquisition, which OG&E ceased recording as a regulatory asset on July 8, 2005;
- increased interest of approximately $3.0 million due to the termination of an interest rate swap in 2005; and
- increased interest of approximately $1.5 million due to increased borrowings from OGE Energy to cover increased construction costs.

These increases in interest expense were partially offset by:

- a decrease in interest expense due to an increase in the allowance for borrowed funds used during construction of approximately $2.3 million; and
- a decrease in interest expense of approximately $1.9 million related to the Company making a deposit with the IRS in August 2006 in anticipation that a portion of prior year deductions will be disallowed, which enabled OG&E to cease accruing interest in August 2006.

Income Tax Expense. Income tax expense was approximately $84.8 million in 2006 as compared to approximately $52.6 million in 2005, an increase of approximately $32.2 million, or 61.2 percent. The increase in income tax expense was primarily due to:

- higher pre-tax income for OG&E;
- the ESOP dividend deduction at OGE Energy in 2006 which was previously recorded at OG&E in 2005 of approximately $7.4 million; and
- a decrease in state tax credits in 2006 of approximately $3.8 million.

Enogex – Continuing Operations

Year Ended December 31, 2007	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	$ **230.4**	$ **799.4**	$ **1,537.9**	$ **(502.5)**	$ **2,065.2**
Cost of goods sold	**97.7**	**603.5**	**1,513.4**	**(502.5)**	**1,712.1**
Gross margin on revenues	**132.7**	**195.9**	**24.5**	---	**353.1**
Other operation and maintenance	**48.5**	**72.1**	**6.8**	---	**127.4**
Depreciation	**17.0**	**28.7**	**0.2**	---	**45.9**
Impairment of assets	**0.5**	---	---	---	**0.5**
Taxes other than income	**11.7**	**3.7**	**0.4**	---	**15.8**
Operating income	$ **55.0**	$ **91.4**	$ **17.1**	$ ---	$ **163.5**

Year Ended December 31, 2006		Transportation and Storage		Gathering and Processing		Marketing		Eliminations		Total
(In millions)										
Operating revenues	$	225.9	$	704.3	$	1,941.3	$	(503.7)	$	2,367.8
Cost of goods sold		100.3		536.7		1,927.1		(503.7)		2,060.4
Gross margin on revenues		125.6		167.6		14.2		---		307.4
Other operation and maintenance		41.2		59.5		9.3		---		110.0
Depreciation		17.9		24.2		0.2		---		42.3
Impairment of assets		---		0.3		---		---		0.3
Taxes other than income		11.8		3.8		0.4		---		16.0
Operating income	$	54.7	$	79.8	$	4.3	$	---	$	138.8

Year Ended December 31, 2005		Transportation and Storage		Gathering and Processing		Marketing		Eliminations		Total
(In millions)										
Operating revenues	$	246.4	$	644.5	$	3,995.3	$	(553.8)	$	4,332.4
Cost of goods sold		147.3		504.3		3,992.6		(553.8)		4,090.4
Gross margin on revenues		99.1		140.2		2.7		---		242.0
Other operation and maintenance		32.9		55.3		8.4		---		96.6
Depreciation		17.3		23.0		0.1		---		40.4
Taxes other than income		11.6		3.4		0.4		---		15.4
Operating income (loss)	$	37.3	$	58.5	$	(6.2)	$	---	$	89.6

Operating Data – Continuing Operations

Year Ended December 31	**2007**	2006	2005
New well connects (includes wells behind central receipt points) (A)	**374**	362	---
New well connects (excludes wells behind central receipt points)	**178**	206	223
Gathered volumes – TBtu/d (B)	**1.05**	0.98	0.92
Incremental transportation volumes – TBtu/d (C)	**0.47**	0.46	0.39
Total throughput volumes – TBtu/d	**1.52**	1.44	1.31
Natural gas processed – TBtu/d	**0.57**	0.54	0.52
Natural gas liquids sold (keep-whole) – million gallons	**252**	244	191
Natural gas liquids sold (purchased for resale) – million gallons	**117**	113	96
Natural gas liquids sold (percent-of-liquids) – million gallons	**16**	14	15
Total natural gas liquids sold – million gallons	**385**	371	302
Average sales price per gallon	**$ 1.048**	$ 0.902	$ 0.873

(A) Includes wells behind central receipt points (as reported to management by third parties). A central receipt point is a single receipt point into a gathering line where a producer aggregates the volumes from one or more wells and delivers them into the gathering system at a single meter site. This information is not available for years prior to 2006 as Enogex's books and records were not maintained in a manner to provide this information for years prior to 2006.
(B) Trillion British thermal units per day.
(C) Incremental transportation volumes consist of natural gas moved only on the transportation pipeline.

2007 compared to 2006. Enogex's operating income increased approximately $24.7 million in 2007 as compared to 2006 primarily due to a higher gross margin in each of Enogex's segments, which was partially offset by higher operating expenses and higher depreciation expense.

Gross Margin

Enogex's consolidated gross margin increased approximately $45.7 million in 2007 as compared to 2006. The increase resulted from a higher gross margin in the transportation and storage business ($7.1 million), the gathering and processing business ($28.3 million) and the marketing business ($10.3 million).

The transportation and storage business contributed approximately $132.7 million of Enogex's consolidated gross margin in 2007 as compared to approximately $125.6 million in 2006, an increase of approximately $7.1 million, or 5.7 percent. The transportation business contributed approximately $97.8 million of Enogex's consolidated gross margin in 2007. The storage business contributed approximately $34.9 million of Enogex's consolidated gross margin in 2007. The transportation and storage gross margin increased primarily due to:

- a reduction in the lower of cost or market adjustments related to natural gas inventories used to operate the pipeline in 2006, which reduced the 2006 gross margin by approximately $8.3 million for which there was no comparable item in 2007;
- increased storage demand fees due to entering into new contracts in 2007 with more favorable terms, which increased the gross margin by approximately $7.8 million;
- a change in Enogex's over-recovered position in its transportation business to an under-recovered position under its FERC-approved fuel tracker in the East Zone in 2007 as compared to 2006, which increased the gross margin by approximately $2.6 million;
- the liability associated with a throughput contract which was transferred to the gathering and processing segment in the second quarter of 2007, which increased the gross margin by approximately $2.4 million; and
- lower electric compression expense associated with its transportation business due to the decreased use of electric compression at Enogex's Harrah processing plant following the loss of a contract during the second quarter of 2007, which increased the gross margin by approximately $1.3 million.

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

- an increased imbalance liability, net of fuel recoveries and natural gas length positions, in its transportation business in 2007, which decreased the gross margin by approximately $6.7 million;
- a decrease in the net gas sales margin in its transportation business due to a decrease in natural gas prices in 2007, which decreased the gross margin by approximately $3.3 million;
- decreased commodity, interruptible and low and high pressure revenues in its transportation business of approximately $2.2 million in 2007 due primarily to renegotiation of contracts to demand-based contracts rather than commodity-based contracts in 2007; and
- decreased commodity and interruptible revenues of approximately $1.1 million in 2007 due primarily to an interruptible storage contract that expired on September 30, 2006.

The gathering and processing business contributed approximately $195.9 million of Enogex's consolidated gross margin in 2007 as compared to approximately $167.6 million in 2006, an increase of approximately $28.3 million, or 16.9 percent. The gathering business contributed approximately $89.4 million of Enogex's consolidated gross margin in 2007. The processing business contributed approximately $106.5 million of Enogex's consolidated gross margin in 2007. The gathering and processing gross margin increased primarily due to:

- an increase in keep-whole margins associated with its processing operations in 2007 as compared to 2006 primarily due to higher commodity spreads, which increased the gross margin by approximately $6.7 million;
- reduced imbalance expense associated with its gathering operations resulting from the recognition in 2006 of an approximately $3.2 million imbalance liability upon the transfer of imbalances previously recognized in the transportation and storage business coupled with a decrease of an approximately $3.4 million imbalance liability, net of fuel recoveries and natural gas length positions, in 2007 as compared to 2006, which increased the gross margin by approximately $6.6 million;
- increased condensate margin associated with its processing operations due to higher prices in 2007 as compared to 2006, which increased the gross margin by approximately $4.6 million;
- renegotiated percent-of-liquids contracts associated with its processing operations entered into during 2007, which increased the gross margin by approximately $3.7 million;
- higher fees associated with its gathering operations from low pressure contracts renegotiated with more favorable terms in 2007, which increased the gross margin by approximately $2.5 million;
- sales of residue gas associated with its processing operations retained from the Atoka processing plant, which began operations in August 2007, that increased the gross margin by approximately $2.2 million;
- higher compression fees associated with its gathering operations resulting from new business in 2007, which increased the gross margin by approximately $2.0 million;
- an increase in new gathering business during 2007, which increased the gross margin by approximately $1.8 million; and
- increased high pressure volumes associated with its gathering operations due to new production in 2007, which increased the gross margin by approximately $1.7 million.

These increases in the gathering and processing gross margin were partially offset by the settlement on a throughput contract in 2007 associated with its processing operations, which decreased the gross margin by approximately $1.9 million.

The marketing business contributed approximately $24.5 million of Enogex's consolidated gross margin in 2007 as compared to approximately $14.2 million in 2006, an increase of approximately $10.3 million, or 72.5 percent. The marketing gross margin increased primarily due to:

- realized gains from physical activity on a transportation contract, which increased the gross margin by approximately $32.7 million;
- a reduction in lower of cost or market adjustments related to natural gas held in storage in 2007 as compared to 2006, which increased the gross margin by approximately $6.6 million; and
- gains on physical sales of natural gas storage inventory activity partially offset by higher fees, which increased the gross margin by approximately $2.9 million.

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

- lower gains on economic hedges of natural gas storage inventory from recording these hedges at market value on December 31, 2007 as compared to December 31, 2006, which decreased the gross margin by approximately $17.0 million;
- lower gains on economic hedges associated with various transportation contracts from recording these hedges at market value on December 31, 2007 as compared to December 31, 2006, which decreased the gross margin by approximately $12.9 million; and
- decreased gains from origination and other marketing and trading activity in 2007, which decreased the gross margin by approximately $2.0 million.

Operating Income

As shown above, Enogex's operating income is calculated by subtracting from the gross margin the following four items: (i) other operation and maintenance expenses, (ii) depreciation, (iii) impairment of assets and (iv) taxes other than income. Enogex's consolidated operating income in 2007 was approximately $163.5 million, a $24.7 million increase from its consolidated operating income in 2006. The increase was attributable primarily to the $45.7 million increase described above in consolidated gross margin, as the aggregate of other operation and maintenance expenses, depreciation expense, impairment of assets and taxes other than income was only approximately $21.0 million higher during 2007 as compared to 2006. The variances in depreciation expense and in taxes other than income on both a consolidated basis and by segment reflect differing levels of depreciable plant in service and a slight decrease in property taxes. The $17.4 million increase in other operation and maintenance expenses on a consolidated basis was primarily due to:

- higher salaries, wages and other employee benefits due to higher incentive compensation and hiring additional employees;
- an increase in outside services, materials and supplies expense and office expense due to an increase in system projects in 2007; and
- a sales and use tax refund received in the prior year.

Specifically, by segment, other operation and maintenance expenses for the transportation and storage business were approximately $7.3 million, or 17.7 percent, higher in 2007 as compared to 2006 primarily due to:

- higher salaries, wages and other employee benefits expense of approximately $5.4 million primarily due to higher incentive compensation and hiring additional employees to support business growth;
- an increase of approximately $4.7 million in outside services, materials and supplies expense and office expense due to an increase in system projects in 2007;
- an increase of approximately $3.3 million due to a fee the marketing business began charging the transportation and storage business in 2007 related to hedging activities;
- higher allocations from OGE Energy for overhead costs of approximately $2.1 million; and
- an increase in professional services expense of approximately $1.2 million for legal and consultant costs for exploration of business expansion in 2007.

These increases were partially offset by:

- lower internal allocations to the other Enogex segments for overhead costs of approximately $5.9 million; and
- a decrease of approximately $1.2 million in rental expense due to the renegotiation of an office building lease in 2007 in addition to the expiration of a building lease in June 2006.

Other operation and maintenance expenses for the gathering and processing business were approximately $12.6 million, or 21.2 percent, higher in 2007 as compared to 2006 primarily due to:

- higher allocations from the transportation and storage business and OGE Energy of approximately $6.8 million primarily due to increased costs in 2007;
- a sales and use tax refund of approximately $2.0 million received in May 2006 related to activity in prior years with no corresponding item in 2007;
- an increase of approximately $1.7 million in materials and supplies expense primarily due to an increase in system projects in 2007;
- an increase of approximately $1.3 million in higher salaries, wages and other employee benefits expense primarily due to hiring additional employees to support business growth; and
- an increase of approximately $1.0 million in higher compressor rental costs resulting from new business in 2007.

Other operation and maintenance expenses for the marketing business were approximately $2.5 million, or 26.9 percent, lower in 2007 as compared to 2006 primarily due to a fee of approximately $3.3 million the marketing business began charging Enogex in 2007 related to hedging activities partially offset by higher allocations of approximately $1.5 million primarily due to increased costs in 2007.

Enogex Consolidated Information

Interest Income. Enogex's consolidated interest income was approximately $9.2 million in 2007 as compared to approximately $11.1 million in 2006, a decrease of approximately $1.9 million, or 17.1 percent, primarily due to interest income earned on cash investments from the cash proceeds from the sale of certain gas gathering assets in the Kinta, Oklahoma area (the "Kinta Assets") in May 2006.

Other Income. Enogex's consolidated other income was approximately $0.9 million in 2007 as compared to approximately $7.7 million in 2006, a decrease of approximately $6.8 million, or 88.3 percent. The decrease was primarily due to:

- a pre-tax litigation settlement of approximately $5.2 million in 2006;
- a pre-tax gain of approximately $1.0 million in the fourth quarter of 2006 from the sale of certain west Texas pipeline assets; and
- a pre-tax gain of approximately $0.5 million in the first quarter of 2006 from the sale of small gathering sections of Enogex's pipeline.

Income Tax Expense. Enogex's consolidated income tax expense was approximately $53.5 million in 2007 as compared to approximately $48.0 million in 2006, an increase of approximately $5.5 million, or 11.5 percent, primarily due to higher pre-tax income.

Non-Recurring and Timing Items. In 2007, Enogex's consolidated net income of approximately $86.2 million included OERI's recorded losses of approximately $2.2 million resulting from recording natural gas storage inventory at the lower of cost or market value. The offsetting gains from the sale of withdrawals from inventory are expected to be realized during the first quarter of 2008. As discussed above, in connection with the Offering, on January 1, 2008, Enogex distributed its shares of common stock of OERI to OGE Energy. Also, in 2007, Enogex had a decrease in net income of approximately $0.3 million relating to an item that Enogex does not consider to be reflective of its ongoing performance related to an impairment of certain long-lived assets.

For 2006, Enogex's consolidated net income, including the discontinued operations discussed below under the caption "Enogex—Discontinued Operations," was approximately $113.5 million, which included OERI's recorded losses of approximately $6.3 million resulting from recording natural gas storage inventory at the lower of cost or market value. The offsetting gains from the sale of withdrawals from inventory were realized during the first quarter of 2007. Also, in 2006, Enogex had an increase in net income of approximately $41.2 million relating to various items that Enogex does not consider to be reflective of its ongoing performance. These increases in consolidated net income include:

- an after-tax gain on the sale of the Kinta Assets in the second quarter of 2006 of approximately $34.1 million;
- the approximately $3.2 million after-tax impact of a litigation settlement;
- income from discontinued operations of approximately $1.9 million;
- a sales and use tax refund related to activity in prior years of approximately $1.3 million after tax;
- an after-tax gain of approximately $0.6 million related to the sale of certain west Texas pipeline assets; and

- an after-tax gain of approximately $0.3 million from the sale of a small gathering section of Enogex's pipeline.

These increases in net income were partially offset by a decrease in net income of approximately $0.2 million, related to an impairment of certain long-lived assets.

2006 compared to 2005

Enogex's consolidated operating revenues and cost of goods sold decreased in 2006 approximately $2.0 billion, or 45.4 percent, and $2.0 billion, or 49.6 percent, respectively, as compared to 2005 primarily due to lower revenues and related costs in Enogex's marketing business, reflecting a reduction in trading activities due to a shift in strategy in Enogex's marketing business as Enogex continued to implement its refocused strategy that seeks to minimize the amount of capital employed and to complement better Enogex's businesses.

Gross Margin

Enogex's consolidated gross margin increased approximately $65.4 million in 2006 as compared to 2005 primarily due to increased gross margin in each of its businesses largely as a result of higher commodity spreads and business growth in 2006 as compared to 2005.

The transportation and storage business contributed approximately $125.6 million of Enogex's gross margin in 2006 as compared to approximately $99.1 million in 2005, an increase of approximately $26.5 million, or 26.7 percent. The transportation and storage gross margin increased primarily due to:

- better management of gas pipeline imbalances as Enogex reduced its exposure to gas imbalances while taking advantage of favorable market price movement in 2006 and the transfer of certain imbalance liabilities previously carried by the transportation and storage business in 2005 to the gathering and processing business in 2006, which increased the gross margin by approximately $11.5 million in 2006;
- increased commodity, interruptible and low and high pressure revenues primarily due to increased customer production and an increase in the allocated portion of bundled rates in 2006 resulting in increased rates of approximately $0.02 per MMBtu being recognized, which increased the gross margin by approximately $6.2 million in 2006;
- a change in Enogex's 2005 accounting estimate of the volume of natural gas in its natural gas storage inventory, which reduced the 2005 gross margin by approximately $5.7 million;
- improved recovery of fuel as Enogex transitioned to zonal fuel rates in 2006, which increased the gross margin by approximately $4.7 million;
- increased gross margin, recognized on natural gas sales of $0.628 per MMBtu as compared to 2005 due to favorable market conditions, which increased the gross margin by approximately $3.5 million; and
- storage field hedging gains, which increased the gross margin by approximately $3.5 million.

These increases in the transportation and storage gross margin were partially offset by a lower of cost or market adjustment related to natural gas inventory used to operate Enogex's pipelines during 2006, which reduced the 2006 gross margin by approximately $8.3 million. There was no comparable item recorded during 2005.

The gathering and processing business contributed approximately $167.6 million of Enogex's gross margin in 2006 as compared to approximately $140.2 million in 2005, an increase of approximately $27.4 million, or 19.5 percent. The gathering and processing gross margin increased primarily due to:

- increased net keep-whole margins primarily due to a $1.06 per MMBtu increase in natural gas prices coupled with an increase in NGL prices and increased volumes of 24.0 million gallons due to business growth, which increased the gross margin by approximately $25.3 million;
- new percent-of-liquids contracts entered into during 2006, which increased the gross margin by approximately $6.0 million;
- increased contractual fuel gains primarily due to an increase of approximately $1.33 per MMBtu in recognized natural gas market prices in 2006 as compared to 2005, which increased the gross margin by approximately $4.9 million;
- new fixed fee contracts entered into during 2006, which increased the gross margin by approximately $2.8 million; and
- a reduction in Enogex's over-recovered fuel position as it transitioned to zonal fuel rates in 2006, which increased the gross margin by approximately $2.5 million.

These increases in the gathering and processing gross margin were partially offset by the recognition of imbalance expense in 2006 (previously carried by the transportation and storage business in 2005), which reduced gross margin by approximately $13.8 million in 2006.

The marketing business contributed approximately $14.2 million of Enogex's consolidated gross margin in 2006 as compared to approximately $2.7 million in 2005, an increase of approximately $11.5 million. The marketing gross margin increased primarily due to:

- gains in storage activity due to timing, resulting from recording Enogex's storage hedges at market value at December 31, 2006 and an increase in storage capacity, which increased the gross margin by approximately $13.2 million;
- a correction to the accounting procedure for park and loan transactions (natural gas storage transactions) in the first quarter of 2005, which decreased the gross margin in the first quarter of 2005 by approximately $7.7 million (see Note 15 of Notes to Consolidated Financial Statements); and
- an increase in the spread between natural gas prices at the receipt location of the Cheyenne Hub near the Colorado and Wyoming border and the natural gas prices of the delivery locations in south central Kansas, which increased the gross margin by approximately $7.6 million.

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

- a lower of cost or market adjustment related to natural gas in storage during 2006, which reduced the 2006 gross margin by approximately $9.9 million; and
- lower gains in trading and park and loan transactions due to a lower level of activity in Enogex's marketing business and less favorable market conditions, which reduced the gross margin by approximately $6.0 million.

Park and loan transactions are planned or managed gas imbalances related to the marketing of natural gas.

Operating Income

Enogex's consolidated operating income in 2006 was approximately $138.8 million, a $49.2 million increase from its consolidated operating income in 2005. The increase was attributable primarily to the $65.4 million increase described above in consolidated gross margin, as the aggregate of other operation and maintenance expenses, depreciation expense, impairment of assets and taxes other than income was only approximately $16.2 million higher during 2006 as compared to 2005. The variance in depreciation expense and in taxes other than income on a consolidated basis and by business segment was attributable primarily to new assets placed into service and slightly higher property taxes. The $13.4 million increase in other operation and maintenance expenses on a consolidated basis was primarily due to:

- higher salaries, wages and other employee benefits of approximately $12.7 million primarily due to higher incentive compensation and hiring additional employees to support business growth; and
- higher materials and supplies costs of approximately $2.7 million primarily related to work performed to maintain the integrity and safety of Enogex's pipelines, higher cost of materials and increased material used at newly added facilities.

These same factors were the primary reasons for the increases in other operation and maintenance expenses by segment.

Specifically, by segment, other operation and maintenance expenses for the transportation and storage business were approximately $8.3 million, or 25.2 percent, higher in 2006 as compared to 2005 primarily due to:

- higher salaries, wages and other employee benefits expense of approximately $14.8 million primarily due to higher incentive compensation and hiring additional employees to support business growth;
- decreased capitalized labor of approximately $3.2 million; and
- higher materials and supplies expense of approximately $1.7 million.

These increases were partially offset by a change in 2006 in Enogex's internal methods for allocating other operation and maintenance expenses, which lowered the allocations by OGE Energy to the transportation and storage business by approximately $10.3 million.

Other operation and maintenance expenses for the gathering and processing business were approximately $4.2 million, or 7.6 percent, higher in 2006 as compared to 2005 primarily due to:

- an approximately $9.6 million increase resulting from the change in such allocation method; and
- higher materials and supplies expense of approximately $1.0 million.

These increases were partially offset by:

- lower salaries, wages and other employee benefits of approximately $5.7 million; and
- a sales and use tax refund of approximately $2.0 million pertaining to activity in prior years.

Other operation and maintenance expenses for the marketing business were approximately $0.9 million, or 10.7 percent, higher in 2006 as compared to 2005 primarily due to a change in allocation methods of approximately $0.7 million and higher wages, salaries and other employee benefits of approximately $0.4 million.

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Interest Income. Consolidated interest income was approximately $11.1 million in 2006 as compared to approximately $2.9 million in 2005, an increase of approximately $8.2 million primarily due to interest income earned on cash investments from the cash proceeds from the sale of Enogex Arkansas Pipeline Corporation ("EAPC") in October 2005 and the sale of the Kinta Assets in May 2006.

Other Income. Consolidated other income was approximately $7.7 million in 2006 as compared to approximately $0.8 million in 2005, an increase of approximately $6.9 million. The increase in other income was primarily due to:

- a pre-tax litigation settlement of approximately $5.2 million in 2006;
- a pre-tax gain of approximately $1.0 million in the fourth quarter of 2006 from the sale of certain west Texas pipeline assets; and
- a pre-tax gain of approximately $0.5 million in the first quarter of 2006 from the sale of small gathering sections of Enogex's pipeline.

Income Tax Expense. Consolidated income tax expense was approximately $48.0 million in 2006 as compared to approximately $20.4 million in 2005, an increase of approximately $27.6 million primarily due to higher pre-tax income.

Non-Recurring and Timing Items. For 2006, Enogex's consolidated net income, including the discontinued operations discussed below under the caption "—Discontinued Operations," was approximately $113.5 million, which included OERI's recorded losses of approximately $6.3 million resulting from recording natural gas inventory at the lower of cost or market value. The offsetting gains from the sale of withdrawals from inventory were realized during the first quarter of 2007. Also, in 2006, Enogex had an increase in net income of approximately $41.2 million relating to various items that Enogex does not consider to be reflective of its ongoing performance. These increases in net income include:

- an after-tax gain on the sale of the Kinta Assets in the second quarter of 2006 of approximately $34.1 million;
- the approximately $3.2 million after-tax impact of a litigation settlement;
- income from discontinued operations of approximately $1.9 million;
- a sales and use tax refund related to activity in prior years of approximately $1.3 million after tax;
- an after-tax gain of approximately $0.6 million related to the sale of certain west Texas pipeline assets; and
- an after-tax gain of approximately $0.3 million from the sale of a small gathering section of Enogex's pipeline.

These increases in net income were partially offset by a decrease in net income of approximately $0.2 million related to an impairment of certain long-lived assets.

For 2005, Enogex's consolidated net income, including the discontinued operations discussed below under the caption "—Discontinued Operations," was approximately $89.8 million, which included OERI's recorded losses of approximately $1.2 million resulting from recording economic storage hedges at market value. The offsetting gains from the sale of withdrawals from inventory were realized during the first quarter of 2006. Also, in 2005, Enogex had an increase in net income of approximately $45.3 million relating to various items that it does not consider to be reflective of the ongoing profitability of its business. These increases in net income include:

- an after-tax gain on the sale of EAPC in October 2005 of approximately $36.7 million;

- income from discontinued operations of approximately $11.3 million;
- an after-tax gain on the sale of Enerven in August 2005 of approximately $1.8 million; and
- income from a sales tax refund related to activity in prior years of approximately $0.2 million.

These increases to net income were partially offset by a correction to the accounting procedure for park and loan transactions in 2005 of approximately $4.7 million.

Enogex** - **Discontinued Operations

In May 2006, Enogex's wholly owned subsidiary, Enogex Gas Gathering, L.L.C. ("Gathering"), sold the Kinta Assets, which included approximately 568 miles of gathering pipeline and 22 compressor units, for approximately $92.9 million. Enogex recorded an after tax gain of approximately $34.1 million from this sale in the second quarter of 2006.

In October 2005, Enogex sold its interest in EAPC, which held a 75 percent interest in the NOARK Pipeline System Limited Partnership, for approximately $177.4 million. Enogex recorded an after tax gain of approximately $36.7 million from this sale in the fourth quarter of 2005.

In August 2005, Enogex Compression Company, LLC ("Enogex Compression") sold its interest in Enerven, a joint venture focused on the rental of natural gas compression assets, for approximately $7.3 million. Enogex Compression recognized an after tax gain of approximately $1.8 million from this sale in the third quarter of 2005.

The Consolidated Financial Statements of the Company have been reclassified to reflect the above sales as discontinued operations. Accordingly, revenues, costs and expenses and cash flows from these sales 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. As the above sales occurred prior to 2007, there are no results of operations for discontinued operations during 2007. Results for these discontinued operations are summarized and discussed below.

Year Ended December 31 *(In millions)*	**2007**	2006	2005
Operating revenues	**$** ---	$ 9.4	$ 106.0
Cost of goods sold	---	4.9	69.5
Gross margin on revenues	---	4.5	36.5
Other operation and maintenance	---	1.0	7.5
Depreciation	---	0.3	5.8
Taxes other than income	---	0.1	1.3
Operating income	---	3.1	21.9
Interest income	---	---	0.2
Other income	---	56.0	66.2
Other expense	---	---	0.1
Interest expense	---	---	4.0
Income before taxes	---	59.1	84.2
Income tax expense	---	23.1	34.4
Net income	**$** ---	$ 36.0	$ 49.8

2007 compared to 2006. Following the sale of the Kinta Assets in May 2006, no operations of the Kinta Assets are reflected in the Consolidated Financial Statements.

2006 compared to 2005. Gross margin decreased approximately $32.0 million, or 87.7 percent, in 2006 as compared to 2005 primarily due to the sale of EAPC in October 2005, the sale of the Kinta Assets in May 2006 and a decrease in natural gas purchases and sales due to a decrease in natural gas transported prior to these assets being sold.

Operation and maintenance expense decreased approximately $6.5 million, or 86.7 percent, in 2006 as compared to 2005 primarily due to the sale of EAPC in October 2005 and the sale of the Kinta Assets in May 2006.

Depreciation expense decreased approximately $5.5 million, or 94.8 percent, in 2006 as compared to 2005 primarily due to the sale of EAPC in October 2005 and ceasing depreciation expense in January 2006 when the Kinta Assets were reported as a discontinued operation.

Taxes other than income decreased approximately $1.2 million, or 92.3 percent, in 2006 as compared to 2005 for ad valorem taxes primarily due to the sale of EAPC in October 2005.

Other income decreased approximately $10.2 million, or 15.4 percent, in 2006 as compared to 2005 due to the sale of the Kinta Assets in May 2006 partially offset by the sale of EAPC in October 2005 and the sale of Enerven in August 2005.

Interest expense decreased approximately $4.0 million, or 100.0 percent, in 2006 as compared to 2005 due to the sale of EAPC in October 2005 and the use of a portion of the sale proceeds to repay EAPC long-term debt.

Income tax expense increased approximately $11.3 million, or 32.8 percent, in 2006 as compared to 2005 primarily due to the sale of the Kinta Assets in May 2006 partially offset by the sale of EAPC in October 2005 and the sale of Enerven in August 2005.

Financial Condition

The balance of Cash and Cash Equivalents was approximately $8.8 million and $47.9 million at December 31, 2007 and 2006, respectively, a decrease of approximately $39.1 million, or 81.6 percent, primarily due to sales proceeds from the sale of the Kinta Assets in May 2006.

The balance of Funds on Deposit was approximately $32.0 million at December 31, 2006 with no balance at December 31, 2007. The decrease was due to an IRS settlement in November 2007 related to the Company's change in method of accounting used to capitalize costs for self-constructed assets as discussed in Note 9 of Notes to Consolidated Financial Statements. The Funds on Deposit balance of approximately $32.0 million was applied against the Company's consolidated income tax liability.

The balance of Fuel Inventories was approximately $82.0 million and $65.6 million at December 31, 2007 and 2006, respectively, an increase of approximately $16.4 million, or 25.0 percent, primarily due to outages at OG&E's Sooner and Muskogee power plants during the third and fourth quarters of 2007, resulting in a higher coal inventory balance at December 31, 2007.

The balance of current Price Risk Management assets was approximately $7.7 million and $38.3 million at December 31, 2007 and 2006, respectively, a decrease of approximately $30.6 million, or 79.9 percent. The decrease was primarily due to OERI's physical purchases and sales activity and corresponding economic hedges recorded at December 31, 2006 being realized during 2007 partially offset by new physical activity and corresponding economic hedges. The decrease was also related to transportation hedges recorded at December 31, 2006 being realized during 2007 partially offset by new Cheyenne Plains and other transportation hedges.

The balance of current Accumulated Deferred Tax Assets was approximately $38.1 million and $10.6 million at December 31, 2007 and 2006, respectively, an increase of approximately $27.5 million, primarily due to an increase in deferred hedging losses at Enogex.

The balance of Fuel Clause Under Recoveries was approximately $27.3 million at December 31, 2007 with no balance at December 31, 2006. This increase was due to the fact the amount billed to Oklahoma retail customers in 2007 was lower than 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 costs in periods of rising fuel 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 and over recovery balances.

The balance of Construction Work in Progress was approximately $179.8 million and $191.1 million at December 31, 2007 and 2006, respectively, a decrease of approximately $11.3 million, or 5.9 percent, primarily due to OG&E's Centennial wind farm being placed in service during January 2007, partially offset by capital projects related to the December 2007 ice storm and various distribution and transmission projects at OG&E and transmission and gathering system projects at Enogex.

The balance of Regulatory Asset - SFAS 158 was approximately $174.6 million and $231.1 million at December 31, 2007 and 2006, respectively, a decrease of approximately $56.5 million, or 24.4 percent, primarily due to pension plan and restoration retirement plan settlement charges and a reduction in the Company's plan obligations due to a better than expected return on plan assets, the Company's contributions to the pension plan and a higher discount rate.

The balance of Other Deferred Charges and Other Assets was approximately $85.6 million and $23.1 million at December 31, 2007 and 2006, respectively, an increase of approximately $62.5 million, primarily due to deferred costs associated with the cancelled Red Rock power plant, deferred costs for storm activities and plan settlement charges which resulted in excess pension expense over the amount granted in rates by the OCC in OG&E's most recent Oklahoma rate case.

The balance of Short-Term Debt was approximately $295.8 million at December 31, 2007 with no balance at December 31, 2006. The increase was primarily due to borrowings to fund OG&E's Centennial wind farm, pension plan funding and daily operational needs of the Company.

The balance of Accounts Payable was approximately $399.3 million and $295.0 million at December 31, 2007 and 2006, respectively, an increase of approximately $104.3 million, or 35.4 percent, primarily due to accruals for the December 2007 ice storm, increased spending for capital and operating projects at Enogex and timing of outstanding checks clearing the bank.

The balance of Accrued Taxes was approximately $40.0 million and $57.0 million at December 31, 2007 and 2006, respectively, a decrease of approximately $17.0 million, or 29.8 percent, primarily due to a decrease in the Company's estimated income tax liability.

The balance of current Price Risk Management liabilities was approximately $20.6 million and $5.6 million at December 31, 2007 and 2006, respectively, an increase of approximately $15.0 million, primarily due to decreased value of cash flow hedges of NGL sales and corresponding keep-whole natural gas purchases entered into during 2007 of approximately $43.9 million partially offset by collateral payments to the counterparties of approximately $28.5 million.

The balance of Fuel Clause Over Recoveries was approximately $4.2 million and $96.3 million at December 31, 2007 and 2006, respectively, a decrease of approximately $92.1 million, or 95.6 percent. The decrease was due to the fact that the amount billed to retail customers in Oklahoma and Arkansas in 2007 was lower than OG&E's cost of fuel. The $4.2 million balance at December 31, 2007 represents the Arkansas fuel clause over recoveries as the Oklahoma portion was in a fuel clause under recovery position at December 31, 2007. 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.

The balance of Accrued Benefit Obligations was approximately $156.2 million and $231.3 million at December 31, 2007 and 2006, respectively, a decrease of approximately $75.1 million, or 32.5 the percent, primarily due to pension plan contributions during 2007 and plan changes for prior service cost and net loss for the pension, restoration retirement and postretirement plans.

The balance of Accumulated Other Comprehensive Loss was approximately $81.0 million and $28.0 million at December 31, 2007, and 2006, respectively, an increase of approximately $53.0 million, primarily due to hedging losses at Enogex partially offset by plan changes for prior service cost and net loss for the pension, retirement restoration and postretirement plans.

Off-Balance Sheet Arrangements

Off-balance sheet arrangements include any transactions, agreements or other contractual arrangements to which an unconsolidated entity is a party and under which the Company has: (i) any obligation under a guarantee contract having specific characteristics as defined in Financial Accounting Standards Board ("FASB") Interpretation No. 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others"; (ii) a retained or contingent interest in assets transferred to an unconsolidated entity or similar arrangement that serves as credit, liquidity or market risk support to such entity for such assets; (iii) any obligation, including a contingent obligation, under a contract that would be accounted for as a derivative instrument but is indexed to the Company's own stock and is classified in 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 material off-balance sheet arrangements.

Heat Pump Loans

In December 2002, OG&E sold approximately $8.5 million of its heat pump loans in a securitization transaction through OGE Consumer Loan 2002, LLC. In August 2007, OG&E repurchased the outstanding heat pump loan balance of approximately $0.6 million. There was no gain or loss associated with the repurchase of the heat pump loans.

OG&E Railcar Lease Agreement

OG&E leases more than 1,400 railcars used to deliver coal to OG&E's coal-fired generation units. See Note 16 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 acquiring or constructing new facilities and replacing or expanding existing facilities at OG&E and Enogex. Other working capital requirements are primarily related to maturing debt, operating lease obligations, hedging activities, natural gas storage, delays in recovering unconditional fuel purchase obligations and fuel clause under and over recoveries. The Company generally meets its cash needs through a combination of cash generated from operations, 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 (2008)	1 - 3 years (2009-2010)	3 - 5 years (2011-2012)	More than 5 years
OG&E capital expenditures including AFUDC (A)(B)	$3,808.8	$ 788.5	$ 842.9	$ 894.2	$ 1,283.2
Enogex capital expenditures including capitalized interest	1,292.1	292.1	400.0	400.0	200.0
Other Operations capital expenditures	145.0	28.6	39.1	30.0	47.3
Total capital expenditures	5,245.9	1,109.2	1,282.0	1,324.2	1,530.5
Maturities of long-term debt	1,346.4	1.0	400.0	---	945.4
Interest payments on long-term debt	1,061.3	86.5	156.9	108.1	709.8
Pension funding obligations	103.0	50.0	27.0	26.0	N/A
Total capital requirements	7,756.6	1,246.7	1,865.9	1,458.3	3,185.7
Operating lease obligations					
OG&E railcars	45.9	3.7	7.3	34.9	---
Enogex noncancellable operating leases	7.2	1.9	3.4	1.9	---
Total operating lease obligations	53.1	5.6	10.7	36.8	---
Other purchase obligations and commitments					
OG&E cogeneration capacity payments	424.3	88.4	171.8	164.1	N/A
OG&E fuel minimum purchase commitments	428.5	115.1	224.5	69.3	19.6
Other	46.5	5.9	13.0	13.0	14.6
Total other purchase obligations and commitments	899.3	209.4	409.3	246.4	34.2
Total capital requirements, operating lease obligations and other purchase obligations and commitments	8,709.0	1,461.7	2,285.9	1,741.5	3,219.9
Amounts recoverable through automatic fuel adjustment clause (C)	(898.7)	(207.2)	(403.6)	(268.3)	(19.6)
Total, net	$7,810.3	$1,254.5	$ 1,882.3	$ 1,473.2	$ 3,200.3

(A) Under current environmental laws and regulations, OG&E may be required to spend approximately $470 million in capital expenditures on its power plants related to regional haze projects. These expenditures are expected to begin in 2008 and would continue over the next five years.
(B) Approximately $434.5 million of the 2008 capital expenditures are related to the proposed acquisition of the Redbud power plant.
(C) 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.

2007 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 $676.5 million and contractual obligations, net of recoveries through automatic fuel adjustment clauses, were approximately $9.7 million resulting in total net capital requirements and contractual obligations of approximately $686.2 million in 2007. Approximately $9.3 million of the 2007 capital requirements were to comply with environmental regulations. This compares to net capital requirements of approximately $662.1 million and net contractual obligations of approximately $10.7 million totaling approximately $672.8 million in 2006, of which approximately $2.7 million was to comply with environmental regulations. During 2007, the Company's sources of capital were internally generated funds from operating cash flows and short-term borrowings (through a combination of bank borrowings and commercial paper). 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 and 2006. During 2005 and 2006, these dispositions generated net sales proceeds of approximately $277.6 million. Sales proceeds generated to date have been used to reduce short-term debt levels and fund capital expenditures.

Additional asset sales could further contribute to the Company's liquidity.

Long-Term Debt Maturities

Maturities of the Company's long-term debt during the next five years consist of $1.0 million in 2008 and $400.0 million in 2010. There are no maturities of the Company's long-term debt in years 2009, 2011 or 2012.

Cash Flows

Year Ended December 31 *(In millions)*	**2007**	2006	2005
Net cash provided from operating activities	**$ 328.5**	$ 569.5	$ 437.9
Net cash used in investing activities	**(556.3)**	(483.5)	(291.3)
Net cash provided from (used in) financing activities	**188.7**	(137.4)	(234.6)

The reduction of approximately $241.0 million in net cash provided from operating activities in 2007 as compared to 2006 primarily related to lower fuel recoveries from OG&E customers partially offset by changes to other working capital. The increase of approximately $131.6 million in net cash provided from operating activities in 2006 as compared to 2005 primarily related to higher fuel clause recoveries from OG&E customers and a higher level of net income partially offset by changes to price risk management assets and liabilities and changes in working capital.

The increase of approximately $72.8 million in net cash used in investing activities in 2007 as compared to 2006 related to higher levels of capital expenditures. The increase of approximately $192.2 million in net cash used in investing activities in 2006 as compared to 2005 related to higher levels of capital expenditures.

The increase of approximately $326.1 million in net cash provided from financing activities in 2007 as compared to 2006 primarily related to higher levels of short-term debt partially offset by reduced amounts related to the issuance of long-term debt. The reduction of approximately $97.2 million in net cash used in financing activities in 2006 as compared to 2005 primarily related to proceeds from the issuance of long-term debt and maturities of long-term debt partially offset by lower levels of short-term debt.

Future Capital Requirements

Capital Expenditures

The Company's current 2008 to 2013 construction program includes continued investment in OG&E's distribution, generation and transmission system and Enogex's transportation, storage, gathering and processing assets. The Company's current estimates of capital expenditures are approximately: 2008 - $1.1 billion (approximately $434.5 million are related to the proposed acquisition of the Redbud power plant), 2009 - $613.9 million, 2010 - $668.1 million, 2011 - $653.4 million, 2012 - $670.8 million and 2013 - $654.1 million. OG&E also has approximately 430 MWs of contracts with qualified cogeneration facilities ("QF") and small power production producers' ("QF contracts") to meet its current and future expected customer needs. OG&E will continue reviewing all of the supply alternatives to these 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.

Pension and Postretirement Benefit Plans

All eligible employees of the Company and participating affiliates are covered by a non-contributory defined benefit pension plan. During 2007, actual asset returns for the Company's defined benefit pension plan were positively affected by growth in the equity markets. At December 31, 2007, approximately 61 percent of the pension plan assets were invested in listed common stocks with the balance invested in corporate debt and U.S. Government securities. In 2007, asset returns on the pension plan were approximately 4.4 percent as compared to approximately 14.5 percent in 2006. 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 $90.0 million in 2006 to approximately $50.0 million in 2007. 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. In August 2006, legislation was passed that changed the funding requirement for single- and multi-employer defined benefit pension plans as discussed below. During 2008, the Company may contribute up to $50.0 million to its pension plan.

In accordance with SFAS No. 88, "Employer's Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," a one-time settlement charge is required to be recorded by an organization when lump-sum payments or other settlements that relieve the organization from the responsibility for the pension benefit obligation or the retirement restoration benefit obligation during a plan year exceed the service cost and interest cost components of the organization's net periodic pension cost or retirement restoration cost. During 2007 and 2006, the Company experienced an increase in both the number of employees electing to retire and the amount of lump-sum payments to be paid to such employees upon retirement as well as the death of the Company's Chairman and Chief Executive Officer in September 2007. As a result, the Company recorded pension settlement charges in 2007 and 2006 and a retirement restoration plan settlement charge in 2007. The pension settlement charges and retirement restoration plan settlement charge did not require a cash outlay by the Company and did not increase the Company's total pension expense or retirement restoration expense over time, as the charges were an acceleration of costs that otherwise would have been recognized as pension expense or retirement restoration expense in future periods.

(In millions)	OG&E (A)	Enogex	OGE Energy	Total
Pension Settlement Charges:				
2007	**$ 13.3**	**$ 0.5**	**$ 2.9**	**$ 16.7**
2006	$ 13.3	$ 0.8	$ 3.0	$ 17.1
Retirement Restoration Plan Settlement Charge:				
2007	**$ 0.1**	**$ ---**	**$ 2.2**	**$ 2.3**

(A) OG&E's Oklahoma jurisdictional portion of these charges were recorded as a regulatory asset (see Note 1 of Notes to Consolidated Financial Statements for a further discussion).

As discussed in Note 14 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 on or after February 1, 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.

At December 31, 2007, the projected benefit obligation and fair value of assets of the Company's pension plan and restoration of retirement income plan was approximately $522.0 million and $514.2 million, respectively, for an underfunded status of approximately $7.8 million. Also, at December 31, 2007, the accumulated postretirement benefit obligation and fair value of assets of the Company's postretirement benefit plans was approximately $216.8 million and $78.5 million, respectively, for an underfunded status of approximately $138.3 million. The above amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which is recorded as a regulatory asset as discussed in Note 1 of Notes to Consolidated Financial Statements) in the Company's Consolidated Balance Sheet. The amounts in Accumulated Other Comprehensive Loss and as a regulatory asset represent a net periodic pension cost to be recognized in the Consolidated Statements of Income in future periods.

At December 31, 2006, the projected benefit obligation and fair value of assets of the Company's pension plan and restoration of retirement income plan was approximately $585.0 million and $519.4 million, respectively, for an underfunded status of approximately $65.6 million. Also, at December 31, 2006, the accumulated postretirement benefit obligation and fair value of assets of the Company's postretirement benefit plans was approximately $225.4 million and $74.0 million, respectively, for an underfunded status of approximately $151.4 million. The above amounts were recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which was recorded as a regulatory asset as discussed in Note 1 of Notes to Consolidated Financial Statements) in the Company's Consolidated Balance Sheet. The entry did not impact the results of operations in 2006 and did not require a usage of cash and is therefore excluded from the Consolidated Statement of Cash Flows. The amounts in Accumulated Other Comprehensive Loss and as a regulatory asset represent a net periodic pension cost to be recognized in the Consolidated Statements of Income in future periods.

Pension Plan Costs and Assumptions

On August 17, 2006, President Bush signed The Pension Protection Act of 2006 (the "Pension Protection Act") into law. The Pension Protection Act makes changes to important aspects of qualified retirement plans. Among other things, it introduces a new funding requirement for single- and multi-employer defined benefit pension plans, provides legal certainty on a prospective basis for cash balance and other hybrid plans and addresses contributions to defined contribution plans, deduction limits for contributions to retirement plans and investment advice provided to plan participants.

Many of the changes enacted as part of the Pension Protection Act are required to be implemented as of the first plan year beginning in 2008. While the Company generally has until the last day of the first plan year beginning in 2009 to reflect those changes as part of the plan document, plans must nevertheless comply in operation as of each provision's effective date. The Company is taking steps now to ensure that its plans, as well as participants and outside administrators, are aware of the changes. In some instances, changes will necessitate notices to participants and/or changes in the plan's administrative forms.

Optional Redemption of Long-Term Debt

OG&E's $125.0 million principal amount 6.65 percent Senior Notes ("Senior Notes") due July 15, 2027, included a one-time option of the holders to redeem the notes on July 15, 2007, at 100 percent of the principal amount with accrued and unpaid interest. In July 2007, $50,000 of the Senior Notes were redeemed by the holders and retired.

Adoption of FIN No. 48

The Company adopted the provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109," on January 1, 2007. As a result of the implementation of FIN No. 48, the Company recognized an approximate $6.2 million increase in the accrued interest liability. The after-tax effect, of approximately $3.8 million, was accounted for as a reduction to the January 1, 2007 balance of retained earnings. The balance of uncertain tax positions at January 1, 2007 consisted of approximately $171.6 million of tax positions associated with the capitalization of self-constructed assets discussed in Note 9 of Notes to Consolidated Financial Statements. On November 27, 2007, OG&E reached a final settlement with the IRS related to the tax method of accounting, which resulted in the reversal of approximately $9.5 million of previously accrued interest expense related to this previously uncertain tax position.

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, commodity prices, levels of drilling activity, 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 cash generated from operations, proceeds from the sale of assets, proceeds from the issuance of long and short-term debt and proceeds from the sales of common stock to the public through the Company's Automatic Dividend Reinvestment and Stock Purchase Plan or other offerings 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.

Issuance of New Long-Term Debt

In January 2008, OG&E issued $200.0 million of 6.45% senior notes due February 1, 2038. The proceeds from the issuance were used to repay commercial paper borrowings.

Short-Term Debt

Short-term borrowings generally are used to meet working capital requirements. At December 31, 2007, the Company had approximately $295.0 million in outstanding commercial paper borrowings. Also, OG&E has the necessary regulatory approvals to incur up to $800 million in short-term borrowings at any time for a two-year period beginning January 1, 2007 and ending December 31, 2008.

In December 2006, the Company and OG&E amended and restated their revolving credit agreements to total in the aggregate $1.0 billion, $600 million for the Company and $400 million for OG&E. Each of the credit facilities has a five-year term with an option to extend the term for two additional one-year periods. In November 2007, the Company and OG&E utilized one of these one-year extensions to extend the maturity of their credit agreements to December 6, 2012. Also, each of these credit facilities has an additional option at the end of the two renewal options to convert the outstanding balance to a one-year term loan. See Note 13 of Notes to Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

It is currently expected that Enogex will enter into a $250 million credit facility for working capital, capital expenditures, including acquisitions, and other corporate purposes during the first quarter of 2008.

Future Financings Under Carbon Principles

In February 2008, three of the largest global financial institutions presented a set of principles ("Carbon Principles") for meeting energy needs in the U.S. that they said balance cost, reliability and greenhouse gas concerns. These Carbon Principles focus on a portfolio approach that includes efficiency, renewable and low carbon power sources, as well as centralized generation sources in light of concerns regarding the impact of greenhouse gas emissions while recognizing the need to provide reliable power at a reasonable cost to consumers. According to financial institutions advocating the Carbon Principles, they are intended to create an industry best practice for the evaluation of options to meet the electric power needs of the U.S. in an environmentally responsible and cost effective manner. Some of the key points of the Carbon Principles are:

- Encourage clients to pursue cost-effective energy efficiency taking into consideration the potential value of avoided carbon dioxide emissions;
- Encourage clients to invest in cost-effective renewables and distributed energy technologies; and
- Educate clients, regulators and other industry participants regarding the additional diligence required for fossil fuel generation financings and encourage regulatory and legislative changes that facilitate carbon capture and storage to reduce carbon dioxide emissions.

The advocates of the Carbon Principles would apply an enhanced diligence process to financings for companies that have announced plans to construct fossil fuel generation plants in the U.S. of over 200 MWs. The adoption of these Carbon Principles could negatively affect OG&E's ability to obtain financing in the future related to coal generation or expansion of capacity.

Common Stock

See Note 10 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 effect on the Company's Consolidated Financial Statements. 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, asset retirement obligations, fair value and cash flow hedges, regulatory assets and liabilities, unbilled revenues for OG&E, operating revenues for Enogex, natural gas purchases for Enogex, the allowance for uncollectible accounts receivable and the valuation of energy purchase and sale contracts. The selection, application and disclosure of the following critical accounting estimates have been discussed with the Company's Audit Committee.

Consolidated (including all Company segments)

Pension and Postretirement Benefit Plans

The Company has defined benefit retirement and postretirement plans that cover substantially all of the Company's employees. 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 14 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 pension plan. The following table indicates the sensitivity of the pension plan funded status to these variables.

	Change	Impact on Funded Status
Actual plan asset returns	+/- 5 percent	+/- $25.7 million
Discount rate	+/- 0.25 percent	+/- $16.9 million
Contributions	+ $10.0 million	+ $10.0 million
Expected long-term return on plan assets	+/- 1 percent	None

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 flows. 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 Company had no material impairments during 2007, 2006 or 2005.

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. When appropriate, 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 otherwise disclosed in this Annual Report on Form 10-K, 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 Notes 16 and 17 of Notes to Consolidated Financial Statements and Item 3 in this Annual Report on Form 10-K.

Asset Retirement Obligations

In accordance with FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations," an entity was required to recognize a liability for the fair value of an asset retirement obligation ("ARO") that was conditional on a future event if the liability's fair value could be reasonably estimated. The fair value of a liability for the conditional ARO was recognized when incurred. Uncertainty surrounding the timing and method of settlement of a conditional ARO was factored into the measurement of the liability when sufficient information existed. However, in some cases, there was insufficient information to estimate the fair value of an ARO. In these cases, the liability was initially recognized in the period in which sufficient information was available for an entity to make a reasonable estimate of the liability's fair value. The Company did not recognize any new AROs during 2007; however, the Company has identified certain AROs that have not been recorded because the Company determined that these assets, primarily related to Enogex's processing plants and compression sites, have indefinite lives.

Hedging Policies

Enogex engages in cash flow hedge transactions to manage commodity risk. Enogex may hedge its forward exposure to manage the impact of changes in commodity prices. Hedges of anticipated transactions are documented as cash flow hedges pursuant to SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and are executed based upon management-established price targets. During 2005, Enogex utilized hedge accounting under SFAS No. 133 to manage commodity exposure for contractual length and operational storage natural gas, keep-whole natural gas and certain types of NGL hedges. During 2006, Enogex utilized hedge accounting under SFAS No. 133 to manage commodity exposure for contractual length and operational storage natural gas, keep-whole natural gas, NGL hedges and certain transportation hedges. During 2007, Enogex utilized hedge accounting under SFAS No. 133 to manage commodity exposure for contractual length and operational storage natural gas, keep-whole natural gas, NGL hedges and certain transportation and natural gas inventory hedges. 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 engage in cash flow and fair value hedge transactions to modify the rate composition of the debt portfolio. During 2005, 2006 and 2007, OG&E entered into 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. The treasury lock agreements in

2005 and 2006 qualified as cash flow hedges under SFAS No. 133. The objective of these treasury lock agreements was to protect against the variability of future interest payments of long-term debt that was issued by OG&E.

Electric Utility Segment

Regulatory Assets and Liabilities

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

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 Company adopted certain provisions of SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132R," effective December 31, 2006, which required the Company to separately disclose the items that had not yet been recognized as components of net periodic pension cost including, net loss, prior service cost and net transition obligation at December 31, 2006. For companies not subject to SFAS No. 71, SFAS No. 158 required these charges to be included in Accumulated Other Comprehensive Income. However, for companies subject to SFAS No. 71, these charges were allowed to be recorded as a regulatory asset if: (i) the utility had historically recovered and currently recovers pension and postretirement benefit plan expense in its electric rates; and (ii) there was no negative evidence that the existing regulatory treatment will change. OG&E met both criteria and, therefore, recorded the net loss, prior service cost and net transition obligation as a regulatory asset as these expenses are probable of future recovery. If, in the future, the regulatory bodies indicate a change in policy related to the recovery of pension and postretirement benefit plan expenses, this could cause the SFAS No. 158 regulatory asset balance to be reclassified to Accumulated Other Comprehensive Income.

Unbilled Revenues

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, 2007, 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 $0.2 million. At December 31, 2007 and 2006, Accrued Unbilled Revenues were approximately $45.7 million and $39.7 million, respectively. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

Allowance for Uncollectible Accounts Receivable

Customer balances are generally written off if not collected within six months after the final billing date. The allowance for uncollectible accounts receivable is calculated by multiplying the last six months of electric revenue by the provision rate. The provision rate is based on a 12-month historical average of actual balances written off. To the extent the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. At December 31, 2007, if the provision rate were to increase or decrease by 10 percent, this would cause a change in the uncollectible expense recognized of approximately $0.3 million. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Consolidated Balance Sheets and is included in Other Operation and Maintenance Expense on the Consolidated Statements of Income. The allowance for uncollectible accounts receivable was approximately $3.4 million and $3.3 million at December 31, 2007 and 2006, respectively.

Natural Gas Transportation and Storage, Gathering and Processing and Marketing Segments

Operating Revenues

Operating revenues for gathering, processing, transportation and storage services for Enogex are recorded each month based on the current month's estimated volumes, contracted prices (considering 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 NGLs 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.

Natural Gas Purchases

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.

Energy Purchase and Sale Contracts

The Company’s activities include the marketing and hedging of natural gas and NGLs. 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 presented at fair value in Price Risk Management Assets, Price Risk Management Liabilities or against the brokerage deposits in Other Current Assets on the Consolidated Balance Sheets. The offsetting gains and losses from changes in the fair value are recognized in earnings or, for transactions designated and qualifying as cash flow hedges according to SFAS No. 133, are presented in Other Comprehensive Income. Recognized gains and losses on energy contracts are presented in Operating Revenues on the Consolidated Statements of Income.

In nearly all cases, independent market prices are obtained and compared to the values used in determining the fair value, 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 of transactions not designated as cash flow hedges is subject to mark-to-market risk loss limitations provided under the Company’s risk policies. Management utilizes models to estimate the fair value of the Company’s energy contracts including derivatives that do not have an independent market price. At December 31, 2007, unrealized mark-to-market losses were approximately $0.9 million, which included approximately $0.3 million of unrealized mark-to-market losses that were calculated utilizing models. At December 31, 2007, a price movement of one percent for prices verified by independent parties would result in unrealized mark-to-market gains or losses of less than $0.1 million and a price movement of five percent on model-based prices would result in unrealized mark-to-market gains or losses of approximately $0.1 million.

Natural Gas Inventory

Natural gas inventory is held by Enogex, through its transportation and storage business, and by OERI. The transportation and storage business maintains natural gas inventory to provide operational support for its pipeline deliveries. In addition, as part of its recurring buy and sell activity, OERI injects and withdraws natural gas into and out of inventory under the terms of its storage capacity contracts. In an effort to mitigate market price exposures, both businesses enter into contracts or hedging instruments to protect the cash flows associated with their inventory. During 2005, 2006 and 2007, OERI 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 Price Risk Management Assets, Price Risk Management Liabilities or against the brokerage deposits in Other Current Assets with an offsetting gain or loss recorded in current earnings. All natural gas inventory held by Enogex is recorded at the lower of cost or market. During 2007 and 2006, Enogex recorded write-downs to market value related to natural gas storage inventory of approximately $3.6 million and $18.7 million, respectively. The amount of Enogex’s natural gas inventory was approximately $37.7 million and $35.9 million at December 31, 2007 and 2006, 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.

Allowance for Uncollectible Accounts Receivable

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 collection 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 aggregate allowance for uncollectible accounts receivable for the transportation and storage, gathering and processing and marketing segments was approximately $0.4 million and $1.1 million at December 31, 2007 and 2006, respectively.

Accounting Pronouncements

See Notes 1, 3, 4, 6, 9 and 14 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 were postponed in 2001, 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 also 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. OG&E is also subject to competition in various degrees from state-owned electric systems, municipally-owned electric systems, rural electric cooperatives and, in certain respects, from other private utilities, power marketers and cogenerators. OG&E has a franchise to serve in more than 270 towns and cities throughout its service territory.

Commitments and Contingencies

Except as disclosed otherwise in this Annual Report on Form 10-K, 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 Notes 16 and 17 of Notes to Consolidated Financial Statements and Item 3 of Part I in this Annual Report on Form 10-K 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, changes in commodity prices, commodity price volatilities 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, treasury lock agreements and commercial paper. The Company engages in price risk management activities for both trading and non-trading purposes.

Risk Committee and Oversight

Management 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 will report 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 will report to the Risk Oversight Committee.

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

Risk Policies

Management utilizes risk policies to control the amount of market risk exposure. These policies 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. Some of the measures in these policies include value-at-risk ("VaR") limits, position limits, tenor limits and stop loss limits.

The Company's price risk management assets and liabilities as of December 31, 2007 were as follows:

	Commodity	Notional Value (MMBtu)	Maturity	Fair Value
		(dollars in millions)		
Trading				
Price Risk Management Assets				
Physical Purchases	Natural Gas	7.3	2008	$ 0.2
Physical Sales	Natural Gas	29.6	2008	5.0
Short Physical Options	Natural Gas	27.1	2008	0.9
Long Basis Positions	Natural Gas	13.4	2008	2.9
Long Basis Positions	Natural Gas	0.9	2009	0.2
Total Long Basis Positions				3.1
Short Basis Positions	Natural Gas	3.6	2008	0.3
Total Trading Price Risk Management Assets				$ 9.5
Non-Trading				
Long Financial Swaps/Futures (exclude Basis)	Natural Gas	0.7	2008	$ 0.2
Short Financial Swaps/Futures (exclude Basis)	Natural Gas	1.2	2008	0.4
Long Financial Options	Natural Gas Liquids	1.3	2008	0.2
Long Financial Options	Natural Gas Liquids	1.3	2009	0.8
Long Financial Options	Natural Gas Liquids	1.3	2010	1.4
Total Long Financial Options				2.4
Total Non-Trading Price Risk Management Assets				$ 3.0
Total Price Risk Management Assets				$ 12.5
Amounts offset in Price Risk Management through Master Netting Agreements				(4.5)
Net Price Risk Management Assets				$ 8.0
Trading				
Price Risk Management Liabilities				
Physical Purchases	Natural Gas	22.1	2008	$ 1.1
Physical Sales	Natural Gas	12.1	2008	0.6
Long Physical Options	Natural Gas	2.7	2008	0.5
Long Financial Swaps/Futures (exclude Basis)	Natural Gas	0.2	2008	0.1
Long Basis Positions	Natural Gas	5.5	2008	0.6
Short Basis Positions	Natural Gas	12.9	2008	2.1
Short Basis Positions	Natural Gas	0.9	2009	0.3
Total Short Basis Positions				2.4
Total Trading Price Risk Management Liabilities				$ 5.3
Non-Trading				
Long Financial Swaps/Futures (exclude Basis)	Natural Gas	11.8	2008	$ 10.9
Long Financial Swaps/Futures (exclude Basis)	Natural Gas	10.5	2009	4.4
Long Financial Swaps/Futures (exclude Basis)	Natural Gas	9.8	2010	0.4
Total Long Financial Swaps/Futures (exclude Basis)				15.7
Short Financial Swaps/Futures (exclude Basis)	Natural Gas Liquids	2.5	2008	33.9
Short Financial Swaps/Futures (exclude Basis)	Natural Gas Liquids	1.3	2009	18.8
Short Financial Swaps/Futures (exclude Basis)	Natural Gas Liquids	1.3	2010	14.9
Total Short Financial Swaps/Futures (exclude Basis)				67.6
Treasury Lock Agreements	Interest Rates		2008	1.7
Total Non-Trading Price Risk Management Liabilities				$ 85.0
Total Price Risk Management Liabilities				$ 90.3
Amounts offset in Price Risk Management through Master Netting Agreements				(58.4)
Net Price Risk Management Liabilities				$ 31.9

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

Interest Rate Risk

The Company's exposure to changes in interest rates relates primarily to short-term variable-rate debt, interest rate swap agreements, treasury lock 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.

OG&E entered into two separate treasury lock agreements, effective November 16, 2007 and November 19, 2007, to hedge interest payments on the first $50.0 million and $25.0 million, respectively, of long-term debt that was issued in January 2008. These treasury lock agreements were settled on January 29, 2008 in conjunction with the issuance of long-term debt by OG&E.

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, 2007, 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.

Year ended December 31 *(Dollars in millions)*	2008	2009	2010	2011	2012	Thereafter	Total	12/31/07 Fair Value
Fixed-rate debt (A)								
Principal amount	$ 1.0	$ ---	$ 400.0	$ ---	$ ---	$ 810.0	$ 1,211.0	$ 1,262.2
Weighted-average interest rate	7.07%	---	8.13%	---	---	6.05%	6.74%	---
Variable-rate debt (B)								
Principal amount	---	---	---	---	---	$ 135.4	$ 135.4	$ 135.4
Weighted-average interest rate	---	---	---	---	---	3.70%	3.70%	---

(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 change interest expense by approximately $1.4 million annually.

Commodity Price Risk

The market risks inherent in 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 set by the Risk Oversight Committee. Those trading stop loss limits currently are $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 set by the Risk Oversight Committee for the Company's trading activities, assuming a 95 percent confidence level, currently 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 net commodity position based upon quoted market prices. Market risk is estimated as the potential loss in fair value resulting from a hypothetical 10 percent adverse change in quoted market prices over the next 12 months. The result of this analysis, which may differ from actual results, is as follows at December 31, 2007.

(In millions)	Trading
Commodity market risk, net	$ 0.1

Non-Trading Activities

The prices of natural gas, NGLs and NGL 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 the Company receives 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 Company's operating income. 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 forward price curves. 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 at December 31, 2007.

(In millions)	Non-Trading
Commodity market risk, net	$ 17.7

Management 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. Management applies normal purchases and normal sales to (i) commodity contracts for the purchase and sale of natural gas; (ii) commodity contracts for the sale of NGLs produced by its subsidiary, Enogex Products Corporation; (iii) electric power contracts by OG&E; and (iv) fuel procurement by OG&E.

Credit Risk

Credit risk includes the risk that counterparties that owe the Company money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, the Company may be forced to enter into alternative arrangements. In that event, the Company's financial results could be adversely affected and the Company 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 that is refunded when the account is closed. New residential customers, whose outside credit scores indicate risk, are required to provide a security deposit that is refunded based on customer protection rules defined by the OCC and the APSC. The payment behavior of all existing customers is continuously monitored and, if the payment behavior indicates sufficient risk within the meaning of the applicable utility regulation, 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 position (including credit rating, if available), 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 position of existing counterparties on an ongoing basis.

Item 8. Financial Statements and Supplementary Data.

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

Year ended December 31 *(In millions, except per share data)*	**2007**	2006	2005
OPERATING REVENUES			
Electric Utility operating revenues	**$ 1,835.1**	$ 1,745.7	$ 1,720.7
Natural Gas Pipeline operating revenues	**1,962.5**	2,259.9	4,190.8
Total operating revenues	**3,797.6**	4,005.6	5,911.5
COST OF GOODS SOLD (exclusive of depreciation shown below)			
Electric Utility cost of goods sold	**977.8**	902.5	946.6
Natural Gas Pipeline cost of goods sold	**1,656.9**	2,000.0	3,995.7
Total cost of goods sold	**2,634.7**	2,902.5	4,942.3
Gross margin on revenues	**1,162.9**	1,103.1	969.2
Other operation and maintenance	**436.8**	416.6	394.9
Depreciation	**195.3**	181.4	182.6
Impairment of assets	**0.5**	0.3	---
Taxes other than income	**75.0**	72.1	69.3
OPERATING INCOME	**455.3**	432.7	322.4
OTHER INCOME (EXPENSE)			
Interest income	**2.1**	6.2	3.5
Allowance for equity funds used during construction	---	4.1	---
Other income (loss)	**17.4**	16.3	(0.3)
Other expense	**(23.7)**	(16.7)	(5.5)
Net other income (expense)	**(4.2)**	9.9	(2.3)
INTEREST EXPENSE			
Interest on long-term debt	**87.8**	87.4	80.0
Allowance for borrowed funds used during construction	**(4.0)**	(4.5)	(2.2)
Interest on short-term debt and other interest charges	**6.4**	13.1	12.5
Interest expense	**90.2**	96.0	90.3
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	**360.9**	346.6	229.8
INCOME TAX EXPENSE	**116.7**	120.5	68.6
INCOME FROM CONTINUING OPERATIONS	**244.2**	226.1	161.2
DISCONTINUED OPERATIONS (NOTE 7)			
Income from discontinued operations	---	59.1	84.2
Income tax expense	---	23.1	34.4
Income from discontinued operations	---	36.0	49.8
NET INCOME	**$ 244.2**	$ 262.1	$ 211.0
BASIC AVERAGE COMMON SHARES OUTSTANDING	**91.7**	91.0	90.3
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**92.5**	92.1	90.8
BASIC EARNINGS PER AVERAGE COMMON SHARE			
Income from continuing operations	**$ 2.66**	$ 2.48	$ 1.79
Income from discontinued operations, net of tax	---	0.40	0.55
NET INCOME	**$ 2.66**	$ 2.88	$ 2.34
DILUTED EARNINGS PER AVERAGE COMMON SHARE			
Income from continuing operations	**$ 2.64**	$ 2.45	$ 1.77
Income from discontinued operations, net of tax	---	0.39	0.55
NET INCOME	**$ 2.64**	$ 2.84	$ 2.32
DIVIDENDS DECLARED PER SHARE	**$ 1.3675**	$ 1.3375	$ 1.33

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

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS

December 31 *(In millions)*	**2007**	2006
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 8.8**	$ 47.9
Funds on deposit	---	32.0
Accounts receivable, less reserve of $3.8 and $4.4, respectively	**334.4**	344.3
Accrued unbilled revenues	**45.7**	39.7
Fuel inventories	**82.0**	65.6
Materials and supplies, at average cost	**63.6**	58.7
Price risk management	**7.7**	38.3
Gas imbalances	**6.7**	2.8
Accumulated deferred tax assets	**38.1**	10.6
Fuel clause under recoveries	**27.3**	---
Prepayments	**8.0**	9.0
Other	**7.2**	11.6
Total current assets	**629.5**	660.5
OTHER PROPERTY AND INVESTMENTS, at cost	**44.5**	35.2
PROPERTY, PLANT AND EQUIPMENT		
In service	**6,809.2**	6,307.7
Construction work in progress	**179.8**	191.1
Total property, plant and equipment	**6,989.0**	6,498.8
Less accumulated depreciation	**2,742.7**	2,631.3
Net property, plant and equipment	**4,246.3**	3,867.5
DEFERRED CHARGES AND OTHER ASSETS		
Income taxes recoverable from customers, net	**17.4**	31.1
Regulatory asset - SFAS 158	**174.6**	231.1
Price risk management	**0.3**	1.7
McClain Plant deferred expenses	**12.4**	18.7
Unamortized loss on reacquired debt	**18.9**	20.1
Unamortized debt issuance costs	**8.3**	9.4
Other	**85.6**	23.1
Total deferred charges and other assets	**317.5**	335.2
TOTAL ASSETS	**$ 5,237.8**	$ 4,898.4

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

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS (Continued)

December 31 *(In millions)*	**2007**	2006
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 295.8**	$ ---
Accounts payable	**399.3**	295.0
Dividends payable	**31.9**	31.1
Customer deposits	**55.5**	53.4
Accrued taxes	**40.0**	57.0
Accrued interest	**37.0**	37.7
Accrued compensation	**53.9**	46.0
Long-term debt due within one year	**1.0**	3.0
Price risk management	**20.6**	5.6
Gas imbalances	**11.1**	11.1
Fuel clause over recoveries	**4.2**	96.3
Other	**38.2**	33.2
Total current liabilities	**988.5**	669.4
LONG-TERM DEBT	**1,344.6**	1,346.3
COMMITMENTS AND CONTINGENCIES (NOTE 16)		
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued benefit obligations	**156.2**	231.3
Accumulated deferred income taxes	**853.6**	859.2
Accumulated deferred investment tax credits	**22.0**	26.8
Accrued removal obligations, net	**139.7**	125.5
Price risk management	**11.3**	1.1
Other	**41.0**	35.0
Total deferred credits and other liabilities	**1,223.8**	1,278.9
STOCKHOLDERS' EQUITY		
Common stockholders' equity	**756.2**	741.0
Retained earnings	**1,005.7**	890.8
Accumulated other comprehensive loss, net of tax	**(81.0)**	(28.0)
Total stockholders' equity	**1,680.9**	1,603.8
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 5,237.8**	$ 4,898.4

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 *(In millions)*		**2007**	2006
STOCKHOLDERS' EQUITY			
Common stock, par value $0.01 per share; authorized 125.0 shares; and outstanding 91.8 and 91.2 shares, respectively		**$ 0.9**	$ 0.9
Premium on capital stock		**755.3**	740.1
Retained earnings		**1,005.7**	890.8
Accumulated other comprehensive loss, net of tax		**(81.0)**	(28.0)
Total stockholders' equity		**1,680.9**	1,603.8
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		**(0.6)**	(0.7)
Senior Notes - OG&E			
5.15 %	Senior Notes, Series Due January 15, 2016	**110.0**	110.0
6.50 %	Senior Notes, Series Due July 15, 2017	**125.0**	125.0
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
5.75 %	Senior Notes, Series Due January 15, 2036	**110.0**	110.0
Other Bonds - OG&E			
3.25% - 4.07%	Garfield Industrial Authority, January 1, 2025	**47.0**	47.0
3.24% - 4.03%	Muskogee Industrial Authority, January 1, 2025	**32.4**	32.4
3.35% - 4.11%	Muskogee Industrial Authority, June 1, 2027	**56.0**	56.0
Unamortized discount		**(2.0)**	(2.1)
Enogex Notes			
8.28%	Medium-Term Notes, Series Due 2007	---	3.0
7.07%	Medium-Term Notes, Series Due 2008	**1.0**	1.0
8.125%	Medium-Term Notes, Series Due 2010	**400.0**	400.0
Unamortized swap monetization		**1.8**	2.7
Total long-term debt		**1,345.6**	1,349.3
Less long-term debt due within one year		**1.0**	3.0
Total long-term debt (excluding long-term debt due within one year)		**1,344.6**	1,346.3
Total Capitalization		**$ 3,025.5**	$ 2,950.1

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

(In millions)	Common Stock	Premium on Capital Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
Balance at December 31, 2004	$ 0.9	$ 699.9	$ 659.8	$ (75.0)	$ 1,285.6
Comprehensive income					
Net income for 2005	---	---	211.0	---	211.0
Other comprehensive income, net of tax					
Minimum pension liability adjustment (($30.0) pre-tax)	---	---	---	(18.4)	(18.4)
Deferred hedging gains ($4.7 pre-tax)	---	---	---	2.9	2.9
Amortization of cash flow hedge ($0.5 pre-tax)	---	---	---	0.3	0.3
Other comprehensive loss	---	---	---	(15.2)	(15.2)
Comprehensive income	---	---	211.0	(15.2)	195.8
Dividends declared on common stock	---	---	(120.3)	---	(120.3)
Issuance of common stock	---	14.7	---	---	14.7
Balance at December 31, 2005	0.9	714.6	750.5	(90.2)	1,375.8
Comprehensive income					
Net income for 2006	---	---	262.1	---	262.1
Other comprehensive income, net of tax					
Minimum pension liability adjustment ($147.5 pre-tax)	---	---	---	90.4	90.4
Minimum pension liability adjustment - SFAS No. 158 ($1.1 pre-tax)	---	---	---	0.7	0.7
Deferred hedging gains ($4.1 pre-tax)	---	---	---	2.5	2.5
Amortization of cash flow hedge ($0.5 pre-tax)	---	---	---	0.3	0.3
Other comprehensive income	---	---	---	93.9	93.9
Comprehensive income	---	---	262.1	93.9	356.0
Adjustment to initially apply SFAS 158, net of tax					
Defined benefit pension plan:					
Net loss, net of tax (($33.9) pre-tax)	---	---	---	(20.7)	(20.7)
Prior service cost, net of tax (($6.6) pre-tax)	---	---	---	(4.1)	(4.1)
Defined benefit postretirement plans:					
Net loss, net of tax (($11.7) pre-tax)	---	---	---	(5.4)	(5.4)
Net transition obligation, net of tax (($1.2) pre-tax)	---	---	---	(0.8)	(0.8)
Prior service cost, net of tax (($1.2) pre-tax)	---	---	---	(0.7)	(0.7)
Adj. to initially apply SFAS 158, net of tax	---	---	---	(31.7)	(31.7)
Dividends declared on common stock	---	---	(121.8)	---	(121.8)
Issuance of common stock	---	25.5	---	---	25.5
Balance at December 31, 2006	0.9	740.1	890.8	(28.0)	1,603.8
Comprehensive income					
Net income for 2007	---	---	**244.2**	---	**244.2**
Other comprehensive income, net of tax					
Defined benefit pension plan:					
Net loss, net of tax ($4.4 pre-tax)	---	---	---	**2.7**	**2.7**
Prior service cost, net of tax ($5.4 pre-tax)	---	---	---	**3.3**	**3.3**
Defined benefit postretirement plans:					
Net loss, net of tax ($3.3 pre-tax)	---	---	---	**1.7**	**1.7**
Net transition obligation, net of tax ($0.2 pre-tax)	---	---	---	**0.1**	**0.1**
Prior service cost, net of tax ($0.5 pre-tax)	---	---	---	**0.3**	**0.3**
Deferred hedging gains (losses) (($100.0) pre-tax)	---	---	---	**(61.3)**	**(61.3)**
Amortization of cash flow hedge ($0.4 pre-tax)	---	---	---	**0.2**	**0.2**
Other comprehensive loss	---	---	---	**(53.0)**	**(53.0)**
Comprehensive income	---	---	**244.2**	**(53.0)**	**191.2**
Dividends declared on common stock	---	---	**(125.5)**	---	**(125.5)**
FIN No. 48 adoption (($6.2) pre-tax)	---	---	**(3.8)**	---	**(3.8)**
Issuance of common stock	---	**15.2**	---	---	**15.2**
Balance at December 31, 2007	**$ 0.9**	**$ 755.3**	**$ 1,005.7**	**$ (81.0)**	**$ 1,680.9**

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)*	**2007**	2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES			
Income from continuing operations	**$ 244.2**	$ 226.1	$ 161.2
Adjustments to reconcile income from continuing operations to net cash provided from operating activities			
Minority interest income	**1.0**	---	---
Depreciation	**195.3**	181.4	182.6
Impairment of assets	**0.5**	0.3	---
Deferred income taxes and investment tax credits, net	**16.1**	32.3	21.9
Allowance for equity funds used during construction	---	(4.1)	---
(Gain) loss on sale of assets	**(0.1)**	(1.6)	0.1
Loss on retirement and abandonment of assets	**3.8**	6.0	---
Stock-based compensation expense	**3.6**	3.8	0.9
Excess tax benefit on stock-based compensation	**(2.8)**	(1.4)	---
Price risk management assets	**32.0**	58.2	(62.6)
Price risk management liabilities	**(74.3)**	(83.5)	80.1
Other assets	**(24.8)**	(73.7)	(6.4)
Other liabilities	**(61.5)**	18.1	(2.9)
Change in certain current assets and liabilities			
Funds on deposit	**32.0**	(32.0)	---
Accounts receivable, net	**9.9**	247.1	(106.9)
Accrued unbilled revenues	**(6.0)**	2.1	3.7
Fuel, materials and supplies inventories	**(21.3)**	(4.4)	22.1
Gas imbalance asset	**(3.9)**	29.2	67.8
Fuel clause under recoveries	**(27.3)**	101.1	(46.8)
Other current assets	**5.4**	9.3	12.4
Accounts payable	**104.3**	(215.4)	40.1
Customer deposits	**2.1**	5.6	(0.5)
Accrued taxes	**(13.5)**	(7.2)	53.9
Accrued interest	**(7.0)**	5.8	(0.9)
Accrued compensation	**7.9**	5.7	2.9
Gas imbalance liability	---	(24.9)	19.7
Fuel clause over recoveries	**(92.1)**	96.3	---
Other current liabilities	**5.0**	(10.7)	(4.5)
Net Cash Provided from Operating Activities	**328.5**	569.5	437.9
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures (less allowance for equity funds used during construction)	**(557.7)**	(486.6)	(297.2)
Proceeds from sale of assets	**1.4**	3.2	5.8
Other investing activities	---	(0.1)	0.1
Net Cash Used in Investing Activities	**(556.3)**	(483.5)	(291.3)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from long-term debt	---	217.5	---
Retirement of long-term debt	**(3.1)**	---	(254.3)
Increase (decrease) in short-term debt, net	**295.8**	(250.0)	125.0
Issuance of common stock	**8.2**	14.5	14.7
Excess tax benefit on stock-based compensation	**2.8**	1.4	---
Contributions from partners	**9.7**	---	---
Dividends paid on common stock	**(124.7)**	(120.8)	(120.0)
Net Cash Provided From (Used in) Financing Activities	**188.7**	(137.4)	(234.6)
DISCONTINUED OPERATIONS			
Net cash used in operating activities	---	(19.9)	(43.0)
Net cash provided from investing activities	---	92.8	146.4
Net cash used in financing activities	---	---	(0.1)
Net Cash Provided from Discontinued Operations	---	72.9	103.3
NET (DECREASE) INCREASE IN CASH AND CASH EQUIVALENTS	**(39.1)**	21.5	15.3
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**47.9**	26.4	11.1
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 8.8**	$ 47.9	$ 26.4

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

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 four business segments: (i) electric utility, (ii) natural gas transportation and storage, (iii) natural gas gathering and processing and (iv) natural gas marketing. 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. OG&E 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.

Enogex Inc. and its subsidiaries ("Enogex") are a provider of integrated natural gas midstream services. The vast majority of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located primarily in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex's ongoing operations are organized into two business segments: (1) natural gas transportation and storage and (2) natural gas gathering and processing. Historically, Enogex had also engaged in natural gas marketing through its subsidiary, OGE Energy Resources, Inc. ("OERI"). In connection with the proposed initial public offering of common units of OGE Enogex Partners L.P., a Delaware limited partnership (the "Partnership"), discussed in Note 2, on January 1, 2008, Enogex distributed the stock of OERI to OGE Energy. Enogex's historical consolidated financial statements were prepared from Enogex's books and records related to Enogex's operating assets. Accordingly, the discussion that follows includes the results of OERI, but as of January 1, 2008, Enogex no longer has any interest in the results of OERI.

The Company allocates operating costs to its subsidiaries based on several factors. Operating costs directly related to specific subsidiaries are assigned to those subsidiaries. Where more than one subsidiary benefits from certain expenditures, the costs are shared between those subsidiaries receiving the benefits. Operating costs incurred for the benefit of all subsidiaries are allocated among the subsidiaries, 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:

December 31 *(In millions)*		**2007**		2006
Regulatory Assets				
Regulatory asset - SFAS 158	**$**	**174.6**	**$**	231.1
Deferred storm expenses		**35.9**		---
Fuel clause under recoveries		**27.3**		---
Deferred pension plan expenses		**24.8**		14.7
Unamortized loss on reacquired debt		**18.9**		20.1
Income taxes recoverable from customers, net		**17.4**		31.1
Red Rock deferred expenses		**14.7**		---
McClain Plant deferred expenses		**12.4**		18.7
Cogeneration credit rider under recovery		**3.9**		3.1
Miscellaneous		**0.8**		0.4
Total Regulatory Assets	**$**	**330.7**	**$**	319.2
Regulatory Liabilities				
Accrued removal obligations, net	**$**	**139.7**	**$**	125.5
Fuel clause over recoveries		**4.2**		96.3
Deferred gain on sale of assets		**1.4**		2.7
Miscellaneous		**2.9**		---
Total Regulatory Liabilities	**$**	**148.2**	**$**	224.5

The Company adopted SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132R," effective December 31, 2006, which required the Company to separately disclose the items that had not yet been recognized as components of net periodic pension cost including, net loss, prior service cost and net transition obligation at December 31, 2006. For companies not subject to SFAS No. 71, SFAS No. 158 required these charges to be included in Accumulated Other Comprehensive Income. However, for companies subject to SFAS No. 71, these charges were allowed to be recorded as a regulatory asset if: (i) the utility had historically recovered and currently recovers pension and postretirement benefit plan expense in its electric rates; and (ii) there was no negative evidence that the existing regulatory treatment will change. OG&E met both criteria and, therefore, recorded the net loss, prior service cost and net transition obligation as a regulatory asset as these expenses are probable of future recovery. If, in the future, the regulatory bodies indicate a change in policy related to the recovery of pension and postretirement benefit plan expenses, this could cause the SFAS No. 158 regulatory asset balance to be reclassified to Accumulated Other Comprehensive Income.

The components of the SFAS No. 158 regulatory asset at December 31, 2007 and 2006 are as follows:

December 31 *(In millions)*		**2007**		2006
Defined benefit pension plan and retirement restoration plan:				
Net loss	**$**	**112.3**	$	129.9
Prior service cost		**4.8**		21.9
Defined benefit postretirement plans:				
Net loss		**42.5**		60.3
Net transition obligation		**12.7**		15.2
Prior service cost		**2.3**		3.8
Total	**$**	**174.6**	$	231.1

The following amounts in the SFAS No. 158 regulatory asset at December 31, 2007 are expected to be recognized as components of net periodic benefit cost in 2008:

(In millions)		
Defined benefit pension plan and retirement restoration plan:		
Net loss	**$**	**6.8**
Prior service cost		**1.2**
Defined benefit postretirement plans:		
Net loss		**3.3**
Net transition obligation		**2.6**
Prior service cost		**1.5**
Total	**$**	**15.4**

In accordance with the OCC order received by OG&E in December 2005 in its Oklahoma rate case, OG&E was allowed to recover Oklahoma storm-related expenses exceeding a $3.5 million threshold. During 2007, OG&E's service territory experienced several storms, including a significant ice storm in December 2007. At December 31, 2007, deferred storm-related expenses were approximately $35.9 million. This amount has been recorded as a regulatory asset as OG&E believes these expenses are probable of future recovery.

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 accordance with the OCC order received by OG&E in December 2005 in its Oklahoma rate case, OG&E was allowed to recover a certain amount of pension plan expenses. At December 31, 2007, there was approximately $24.8 million of expenses exceeding this level primarily related to pension settlement charges recorded by the Company during 2006 and 2007 (see Note 14 for a further discussion). These excess amounts have been recorded as a regulatory asset as OG&E believes these expenses are probable of future recovery.

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.

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." The OCC authorized approximately $30.1 million of the $32.8 million regulatory asset balance at December 31, 2005 to be included in OG&E's rate base for purposes of earning a return.

On October 11, 2007, the OCC issued an order denying OG&E and Public Service Company of Oklahoma's ("PSO") request for pre-approval of their proposed 950 megawatt ("MW") Red Rock power plant project. The plant, which was to be built at OG&E's Sooner plant site, was to be 42 percent owned by OG&E, 50 percent owned by PSO and eight percent owned by the Oklahoma Municipal Power Authority ("OMPA"). As a result, on October 11, 2007, OG&E, PSO and the OMPA agreed to terminate agreements to build and operate the plant. At December 31, 2007, OG&E had incurred approximately $17.5 million of capitalized costs associated with the Red Rock power plant project. In December 2007, OG&E filed an application with the OCC requesting authorization to defer, and establish a method for recovery of, approximately $14.7 million of Oklahoma jurisdictional costs associated with the Red Rock power plant project that are currently reflected in Deferred Charges and Other Assets on the Company's Consolidated Balance Sheets. If the request for deferral is not approved, the deferred costs will be expensed. In February 2008, the OCC issued a procedural schedule with a hearing scheduled for May 7, 2008. OG&E expects to receive an order from the OCC in this matter by the end of 2008.

As a result of the acquisition of a 77 percent interest in the 520 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 "2002 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. At December 31, 2007, the McClain Plant regulatory asset was approximately $12.4 million which is being recovered over the remaining two-year time period as authorized in the OCC rate order which began in January 2006. Approximately $15.5 million of the McClain Plant deferred expenses are included in OG&E's rate base for purposes of earning a return.

OG&E's cogeneration credit rider was initially implemented in 2003 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 cogeneration credit rider was updated and approved by the OCC in December of each year through December 2006 and any over/under recovery of the cogeneration credit rider in the current year and prior periods was automatically included in the next year's rider. The balance of the cogeneration credit rider under recovery was approximately $3.9 million and $3.1 million, respectively, at December 31, 2007 and 2006. OG&E filed an application with the OCC in September 2007 to request a new cogeneration credit rider for years after 2007 as OG&E's current cogeneration credit rider expired on December 31, 2007. In December 2007, the OCC issued an order approving a cogeneration credit rider that expires on December 31, 2009. The cogeneration credit rider under recovery was not included in OG&E's rate base and did not otherwise earn a rate of return. The cogeneration credit rider under recovery is included in Other Current Assets 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.

In December 2005, the OCC order in OG&E's Oklahoma rate case required that any gains related to the sale of assets should be returned to customers through adjustments to electric rates. During 2006, OG&E sold certain assets for a gain of approximately $0.3 million which was recorded as a regulatory liability. There were no gains from the sale of assets in 2007. OG&E expects to continue this treatment for any 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 effect on the Company's Consolidated Financial Statements. 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, asset retirement obligations, fair value and cash flow hedges, regulatory assets and liabilities, unbilled revenues for OG&E, operating revenues for Enogex, natural gas purchases for Enogex, the allowance for uncollectible accounts receivable and the valuation of energy purchase and sale contracts.

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 $68.8 million and $45.0 million at December 31, 2007 and 2006, 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 collection of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable was approximately $3.8 million and $4.4 million at December 31, 2007 and 2006, 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 that is refunded when the account is closed. New residential customers, whose outside credit scores indicate risk, are required to provide a security deposit that is refunded based on customer protection rules defined by the OCC and the APSC. The payment behavior of all existing customers is continuously monitored and, if the payment behavior indicates sufficient risk within the meaning of the applicable utility regulation, 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 position (including credit rating, if available), 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 position 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. For 2007 and 2006, these inventories were 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 $7.4 million and $13.7 million for 2007 and 2006, respectively, based on the average cost of fuel purchased. The amount of fuel inventory was approximately $44.3 million and $29.7 million at December 31, 2007 and 2006, respectively.

Effective January 1, 2008, OG&E's inventory that is physically added to or withdrawn from storage or stockpiles will be valued using the weighted-average cost method in accordance with legislation that was passed in Oklahoma in 2007 which required that electric utilities record fuel or natural gas removed from storage or stockpiles using the weighted-average cost method of accounting for inventory. See Note 17 for a further discussion.

Enogex/OERI

Natural gas inventory is held by Enogex, through its transportation and storage business, and by OERI. The transportation and storage business maintains natural gas inventory to provide operational support for its pipeline deliveries. In addition, as part of its recurring buy and sell activity, OERI injects and withdraws natural gas into and out of inventory under the terms of its storage capacity contracts. In an effort to mitigate market price exposures, both businesses enter into contracts or hedging instruments to protect the cash flows associated with their inventory. All natural gas inventory held by Enogex is recorded at the lower of cost or market. During 2007 and 2006, Enogex recorded write-downs to market value related to natural gas storage inventory of approximately $3.6 million and $18.7 million, respectively. The amount of Enogex's natural gas inventory was approximately $37.7 million and $35.9 million at December 31, 2007 and 2006, 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.

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.

Property, Plant and Equipment

OG&E

All property, plant and equipment are recorded at cost. Newly constructed plant is added to plant balances at cost which includes contracted services, direct labor, materials, overhead, transportation costs and the allowance for funds used during construction ("AFUDC"). Replacements of units of property are capitalized as plant. For assets that belong to a common plant account, the replaced plant is removed from plant balances and the cost of such property less net salvage is charged to Accumulated Depreciation. For assets that do not belong to a common plant account, 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 interest in the McClain Plant and, as disclosed below, only this 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 OMPA. OG&E and the 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 was approximately $181.0 million and $180.2 million, respectively, at December 31, 2007 and 2006. The accumulated depreciation associated with OG&E's interest in the McClain Plant was approximately $35.4 million and $25.3 million, respectively, at December 31, 2007 and 2006.

Enogex/OERI

All property, plant and equipment are recorded at cost. Newly constructed plant is added to plant balances at cost which includes contracted services, direct labor, materials, overhead, transportation costs and capitalized interest. Replacements of units of property are capitalized as plant. For assets that belong to a common plant account, the replaced plant is removed from plant balances and charged to Accumulated Depreciation. For assets that do not belong to a common plant account, 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 and related accumulated depreciation are divided into the following major classes at December 31, 2007 and 2006, respectively.

December 31, 2007 *(In millions)*	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
OGE Energy (holding company)			
Property, plant and equipment	**$ 93.0**	**$ 65.4**	**$ 27.6**
OGE Energy Corp. property, plant and equipment	**93.0**	**65.4**	**27.6**
OG&E			
Distribution assets	**2,361.4**	**792.0**	**1,569.4**
Electric generation assets	**2,114.0**	**1,062.8**	**1,051.2**
Transmission assets	**747.3**	**285.7**	**461.6**
Intangible plant	**35.8**	**29.7**	**6.1**
Other property and equipment	**217.0**	**71.7**	**145.3**
OG&E property, plant and equipment	**5,475.5**	**2,241.9**	**3,233.6**
Enogex			
Transportation and storage assets	**729.2**	**191.4**	**537.8**
Gathering and processing assets	**684.0**	**237.2**	**446.8**
Marketing assets	**7.3**	**6.8**	**0.5**
Enogex property, plant and equipment	**1,420.5**	**435.4**	**985.1**
Total property, plant and equipment	**$ 6,989.0**	**$ 2,742.7**	**$ 4,246.3**

December 31, 2006 *(In millions)*	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
OGE Energy. (holding company)			
Property, plant and equipment	$ 80.7	$ 58.0	$ 22.7
OGE Energy Corp. property, plant and equipment	80.7	58.0	22.7
OG&E			
Distribution assets	2,205.3	775.4	1,429.9
Electric generation assets	2,057.4	1,042.5	1,014.9
Transmission assets	663.2	265.1	398.1
Intangible plant	32.0	26.2	5.8
Other property and equipment	196.5	66.1	130.4
OG&E property, plant and equipment	5,154.4	2,175.3	2,979.1
Enogex			
Transportation and storage assets	691.5	177.5	514.0
Gathering and processing assets	564.6	213.4	351.2
Marketing assets	7.6	7.1	0.5
Enogex property, plant and equipment	1,263.7	398.0	865.7
Total property, plant and equipment	$ 6,498.8	$ 2,631.3	$ 3,867.5

Depreciation

OG&E

The provision for depreciation, which was approximately 2.7 percent of the average depreciable utility plant for both 2007 and 2006, 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. In 2008, the provision for depreciation is projected to continue to be approximately 2.7 percent of the average depreciable utility plant. Amortization of intangibles is computed using the straight-line method. Approximately 83 percent of the remaining amortizable intangible plant balance at December 31, 2007 will be amortized over three years with approximately 17 percent of the remaining amortizable intangible plant balance at December 31, 2007 being amortized over their respective lives ranging from four to 25 years.

Enogex/OERI

Depreciation is computed principally on the straight-line method using estimated useful lives of three to 83 years for transportation and storage assets and three to 30 years for gathering and processing assets. For OERI, depreciation is computed principally on the straight-line method using estimated useful lives of three to 10 years. 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.

Asset Retirement Obligations

In accordance with SFAS No. 143, for periods subsequent to the initial measurement of an asset retirement obligations ("ARO"), the Company recognizes period-to-period changes in the liability for an ARO resulting from: (i) the passage of time; and (ii) revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Also, in accordance with FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations," the Company recognizes a liability for the fair value of an 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 is recognized when incurred. Uncertainty surrounding the timing and method of settlement of a conditional ARO is factored into the measurement of the liability when sufficient information existed. However, in some cases, there is insufficient information to estimate the fair value of an ARO. In these cases, the liability is initially recognized in the period in which sufficient information is available for the Company to make a reasonable estimate of the liability's fair value.

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 flows. 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 Company had no material impairments during 2007, 2006 or 2005.

Allowance for Funds Used During Construction

For OG&E, 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 5.78 percent, 7.79 percent and 3.78 percent for the years 2007, 2006 and 2005, respectively. The decrease in the AFUDC rates in 2007 was primarily due to a decrease in equity funds in the AFUDC calculation that resulted from a lower level of construction costs funded by short-term borrowings in 2007.

Collection of Sales Tax

In the course of its operations, OG&E collects sales tax from its customers. OG&E records a current liability when it collects sales taxes from its customers and eliminates this liability when the taxes are remitted to the appropriate governmental authorities. OG&E excludes the sales tax collected from its operating revenues.

Revenue Recognition

OG&E

General

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.

SPP Purchases and Sales

In February 2007, OG&E began participating in the Southwest Power Pool's ("SPP") energy imbalance service market in a dual role as a load serving entity and as a generation owner. The energy imbalance service market requires cash settlements for over or under schedules of generation and load. Market participants, including OG&E, are required to submit resource plans and can submit offer curves for each resource available for dispatch. A function of interchange accounting is to match participants' megawatt-hour ("MWH") entitlements (generation plus scheduled bilateral purchases) against their MWH obligations (load plus scheduled bilateral sales) during every hour of every day. If the net result during any given hour is an entitlement, the participant is credited with a spot-market sale to the SPP at the respective market price for that hour; if the net result is an obligation, the participant is charged with a spot-market purchase from the SPP at the respective market price for that hour. The SPP purchases and sales are not allocated to individual customers. OG&E records the hourly sales to the SPP at market rates in Operating Revenues and the hourly purchases from the SPP at market rates in Cost of Goods Sold in its Consolidated Financial Statements.

Enogex/OERI

Operating revenues for gathering, processing, transportation and storage services for Enogex are recorded each month based on the current month's estimated volumes, contracted prices (considering 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, "Accounting for Derivative Instruments and Hedging Activities." 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, Price Risk Management Liabilities or against the brokerage deposits in Other Current Assets 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

The Company adopted SFAS No. 123 (Revised), "Share-Based Payment," using the modified prospective transition method, effective January 1, 2006, which required 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. See Note 4 for a further discussion related to the Company's stock-based compensation. The following table reflects pro forma net income and income per average common share for 2005 had the Company elected to adopt the fair value recognition provisions of SFAS No. 123, "Accounting for Stock-Based Compensation," for options granted under the Company's stock-based employee compensation plans. For purposes of this pro forma disclosure, the value of the options was determined using a Black-Scholes option pricing formula and amortized to expense over the options' vesting periods. Pro forma information is not included for 2006 as all share-based payments have been accounted for under SFAS No. 123(R).

Year ended December 31 (In millions, except per share data)	2005
Net income, as reported	$ 211.0
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
Pro forma net income	$ 210.5
Income per average common share	
Basic – as reported	$ 2.34
Diluted – as reported	$ 2.32
Basic – pro forma	$ 2.33
Diluted – pro forma	$ 2.32

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 Income (Loss)

The components of accumulated other comprehensive loss at December 31, 2007 and 2006 are as follows:

December 31 *(In millions)*	**2007**	2006
Defined benefit pension plan:		
Net loss, net of tax	**$ (18.0)**	$ (20.7)
Prior service cost, net of tax	**(0.8)**	(4.1)
Defined benefit postretirement plans:		
Net loss, net of tax	**(3.7)**	(5.4)
Net transition obligation, net of tax	**(0.7)**	(0.8)
Prior service cost, net of tax	**(0.4)**	(0.7)
Deferred hedging gains (losses), net of tax	**(55.7)**	5.6
Settlement and amortization of cash flow hedge, net of tax	**(1.7)**	(1.9)
Total accumulated other comprehensive loss, net of tax	**$ (81.0)**	$ (28.0)

Approximately $25.8 million of the deferred hedging losses at December 31, 2007 are expected to be recognized into earnings during 2008.

Defined Benefit Pension and Postretirement Plans

The Company is required to disclose the amounts in accumulated other comprehensive loss at December 31, 2007 that are expected to be recognized as components of net periodic benefit cost in 2008 which are as follows:

(In millions)	
Defined benefit pension plan:	
Net loss, net of tax	**$ 1.0**
Prior service cost, net of tax	**0.2**
Defined benefit postretirement plans:	
Net loss, net of tax	**0.3**
Prior service cost, net of tax	**0.3**
Net transition obligation, net of tax	**0.1**
Total	**$ 1.9**

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 or Enogex have been designated as one of several potentially responsible parties, the amount accrued represents OG&E's or Enogex's estimated share of the cost.

Reclassifications

Certain prior year amounts have been reclassified on the Consolidated Financial Statements to conform to the 2007 presentation primarily related to the net presentation of Price Risk Management Assets and Liabilities as discussed in Note 6.

2. Formation of OGE Enogex Partners L.P.

In May 2007, the Company formed the Partnership as part of its strategy to further develop Enogex's natural gas midstream assets and operations. The Partnership has filed a registration statement with the Securities and Exchange Commission for a proposed initial public offering of its common units, representing limited partner interests in the Partnership (the "Offering"). At the date of this annual report, the registration statement relating to the Offering is not effective. Prior to the closing of the Offering, Enogex Inc., which is currently an Oklahoma corporation, would convert to Enogex LLC, a Delaware limited liability company. In connection with the Offering, the Company is expected to contribute an approximately 25 percent membership interest in Enogex LLC to a wholly owned subsidiary of the Partnership that would serve as Enogex LLC's managing member and would control its assets and operations. A wholly owned subsidiary of the Company will retain the remaining approximately 75 percent membership interest in Enogex LLC. It is currently contemplated that at the completion of the Offering, the Company will indirectly own an approximate 68 percent limited partner interest and a two percent general partner interest in the Partnership.

The completion of the Offering is subject to numerous conditions and no assurances can be made that it will be successfully completed. The Company expects to continue to evaluate strategic alternatives for Enogex, including other transactions that the Company believes could provide long-term value to its shareowners and the proposed initial public offering. The securities offered under the registration statement may not be sold, nor may offers to buy be accepted, prior to the time that the registration statement becomes effective. The information contained in this annual report with respect to the Offering shall not constitute an offer to sell or a solicitation of an offer to buy any securities.

From a financial reporting perspective, the formation of the Partnership had no effect on the Company's financial statements as of and for the periods ended December 31, 2007, 2006 and 2005. In the event that, and beginning with the period in which, the Offering is completed, the Company will consolidate the results of the Partnership with minority interest treatment for the common units of the Partnership owned by unitholders other than the Company or its consolidated subsidiaries.

3. Accounting Pronouncement

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which defines fair value, establishes a framework for measuring fair value in generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 expands disclosures about the use of fair value to measure assets and liabilities in interim and annual periods subsequent to initial recognition. The guidance in SFAS No. 157 applies to derivatives and other financial instruments measured at fair value under SFAS No. 133 at initial recognition and in all subsequent periods. Therefore, SFAS No. 157 nullifies the guidance in footnote 3 of Emerging Issues Task Force 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." SFAS No. 157 also amends SFAS No. 133 to remove the guidance similar to that nullified in EITF 02-3. SFAS No. 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and interim periods within those fiscal years. The provisions of SFAS No. 157 generally are to be applied prospectively as of the beginning of the fiscal year in which it is initially applied. The Company adopted this new standard effective January 1, 2008. The adoption of this new standard is not expected to have a material impact on the Company's consolidated financial position or results of operations.

4. Stock-Based Compensation

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

Prior to January 1, 2006, the Company accounted for the Plans under the recognition and measurement provisions of Accounting Principles Board ("APB") Opinion No. 25, "Accounting for Stock Issued to Employees," as permitted by SFAS No. 123. The Company also previously adopted the disclosure provisions under SFAS No. 123 and SFAS No. 148, "Accounting for Stock-Based Compensation – Transition and Disclosure." The Company recorded compensation expense of approximately $0.9 million pre-tax ($0.5 million after tax) in 2005 related to its performance units in Other Operation and Maintenance Expense in the Consolidated Statement of Income. No compensation expense related to stock options was recognized in 2005 as all options granted under the Plans had an exercise price equal to the market value of the Company's common stock on the grant date. Effective January 1, 2006, the Company adopted SFAS No. 123(R) using the modified prospective transition method. Under that transition method, the Company's compensation cost recognized in the first quarter of 2006 included: (i) compensation cost for all share-based payments granted prior to, but not yet vested as of, January 1, 2006, based on the fair value calculated in accordance with the provisions of SFAS No. 123(R); and (ii) compensation cost for all share-based payments granted in the first quarter of 2006 based on the fair value calculated in accordance with the provisions of SFAS No. 123(R). Results for prior periods were not restated.

As a result of adopting SFAS No. 123(R) on January 1, 2006, the Company recorded compensation expense of approximately $8.6 million pre-tax ($5.3 million after tax, or $0.06 per basic and diluted share) in 2006 related to the Company's share-based payments. Also, as a result of adopting SFAS No. 123(R), the Company recorded a cumulative effect adjustment of approximately $0.4 million pre-tax ($0.2 million after tax, or less than $0.01 per basic and diluted share) on January 1, 2006 for outstanding non-vested share-based compensation grants at December 31, 2005. The Company determined that the cumulative effect adjustment was immaterial for presentation purposes and is, therefore, included in Other Operation and Maintenance Expense in the Consolidated Statement of Income. The Company recorded compensation expense of approximately $3.8 million pre-tax ($2.3 million after tax, or $0.03 per basic and diluted share) in 2007 related to the Company's share-based payments.

The Company issues new shares to satisfy stock option exercises. During 2007, 2006 and 2005, there were 496,565 shares, 738,426 shares and 606,802 shares, respectively, of new common stock issued pursuant to the Company's Plans related to exercised stock options and payouts of earned performance units. The Company received approximately $8.2 million and $14.5 million in 2007 and 2006, respectively, related to exercised stock options.

Prior to the adoption of SFAS No. 123(R), the Company presented all tax benefits of deductions resulting from the exercise of stock options or other share-based payments as operating cash flows in the Consolidated Statements of Cash Flows. SFAS No. 123(R) requires cash flows resulting in tax benefits from tax deductions in excess of the compensation cost recognized for share-based payments ("excess tax benefits") to be classified as financing cash flows. The Company recorded an excess tax benefit of approximately $3.5 million in 2007 related to the Company's 2007 share-based payments. The Company realized an excess tax benefit of approximately $2.8 million in 2007 related to the Company's 2006 share-based payments, which amount was presented as a financing cash inflow and realized when the Company's 2006 income tax return was filed in September 2007. The Company recorded an excess tax benefit of approximately $2.8 million in 2006 related to the Company's 2006 share-based payments. The Company realized an excess tax benefit of approximately $1.4 million in 2006 related to the Company's 2005 share-based payments, which amount was presented as a financing cash inflow and realized when the Company's 2005 income tax return was filed in August 2006. The Company realized an excess tax benefit of approximately $0.8 million during 2005 related to the Company's 2004 share-based payments.

Performance Units

Under the Plans, the Company has issued performance units which represent the value of one share of the Company's common stock. The performance units provide for accelerated vesting if there is a change in control (as defined in the Plans). Each performance unit is subject to forfeiture if the recipient terminates employment with the Company or a subsidiary prior to the end of the three-year award cycle for any reason other than death, disability or retirement. In the event of death, disability or retirement, a participant will receive a prorated payment based on such participant's number of full months of service during the three-year award cycle, further adjusted based on the achievement of the performance goals during the award cycle. The following table is a summary of the terms of the Company's outstanding performance units awarded during 2005, 2006 and 2007.

Condition	Settlement	Vesting Period	SFAS No. 123(R) Classification
Total Shareholder Return	2/3 – Stock (A)	3-year cliff	Equity
	1/3 – Cash	3-year cliff	Liability
Earnings Per Share	2/3 – Stock (A)	3-year cliff	Equity
	1/3 – Cash	3-year cliff	Liability

(A) All of the Company's 2006 and 2007 performance units will be settled in stock.

The performance units granted based on total shareholder return ("TSR") are contingently awarded and will be payable in cash or shares of the Company's common stock (other than performance units awarded in 2006 and 2007, which will be payable only in shares of 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 TSR ranking relative to a peer group of companies. The performance units granted based on earnings per share ("EPS") are contingently awarded and will be payable in cash or shares of the Company's common stock (other than performance units awarded in 2006 and 2007, which will be payable only in shares of common stock) based on the Company's EPS growth over a three-year award cycle compared to a target set at the time of the grant by the Compensation Committee of the Company's Board of Directors. If there is no or only a partial payout for the performance units at the end of the three-year award cycle, the unearned performance units are cancelled. During 2007, 2006 and 2005, the Company awarded 162,730, 239,856 and 201,794 performance units, respectively, to certain employees of the Company and its subsidiaries.

Performance Units – Total Shareholder Return

The Company recorded compensation expense of approximately $2.3 million pre-tax ($1.4 million after tax), $6.5 million pre-tax ($4.0 million after tax) and $0.6 million pre-tax ($0.4 million after tax) in 2007, 2006 and 2005, respectively, related to the performance units based on TSR. The fair value of the performance units based on TSR was estimated on the grant date using a lattice-based valuation model that factors in information, including the expected dividend yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance units. Compensation expense for the performance units settled in stock is a fixed amount determined at the grant date fair value and is recognized over the three-year award cycle regardless of whether performance units are awarded at the end of the award cycle. Compensation expense for the performance units settled in cash is based on the change in the fair value of the performance units for each reporting period. This liability for the performance units will be remeasured at each reporting date until the date of settlement. Dividends are not accrued or paid during the performance period and, therefore, are not included in the fair value calculation. Expected price volatility is based on the historical volatility of the Company's common stock for the past three years and was simulated using the Geometric Brownian Motion process. The risk-free interest rate for the performance unit grants is based on the three-year U.S. Treasury yield curve in effect at the time of the grant. The expected life of the units is based on the non-vested period since inception of the three-year award cycle. There are no post-vesting restrictions related to the Company's performance units based on TSR. The fair value of the performance units based on TSR was calculated based on the following assumptions at the grant date.

	2007	2006	2005
Expected dividend yield	3.6%	4.9%	5.3%
Expected price volatility	15.9%	16.8%	22.3%
Risk-free interest rate	4.47%	4.66%	3.28%
Expected life of units (in years)	2.95	2.85	2.85
Fair value of units granted	$ 24.18	$ 22.93	$ 21.56

A summary of the activity for the Company's performance units based on TSR at December 31, 2007 and changes during 2007 are summarized in the following table. Following the end of a three-year performance period, payout of the performance units based on TSR is determined by the Company's TSR for such period compared to a peer group and payout requires the approval of the Compensation Committee of the Company's Board of Directors. Payouts, if any, are made in two-thirds stock and one-third cash (other than payouts of performance units awarded in 2006 and 2007, which will be made only in common stock) and are considered made when the payout is approved by the Compensation Committee.

(dollars in millions)	Number of Units	Stock Conversion Ratio (A)	Aggregate Intrinsic Value
Units Outstanding at 12/31/06	440,263	1 : 1	
Granted (B)	122,044	1 : 1	
Converted	(132,845)	1 : 1	$ 4.8
Forfeited	(66,314)	1 : 1	
Units Outstanding at 12/31/07	363,148	1 : 1	$ 14.1
Units Fully Vested at 12/31/07 (C)	124,886	1 : 1	$ 5.9

(A) One performance unit = one share of the Company's common stock.

(B) Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.

(C) These performance units, which were awarded in 2005 and became fully vested at December 31, 2007, were certified by the Compensation Committee of the Company's Board of Directors in February 2008.

A summary of the activity for the Company's non-vested performance units based on TSR at December 31, 2007 and changes during 2007 are summarized in the following table:

	Number of Units	Weighted-Average Grant Date Fair Value
Units Non-Vested at 12/31/06	307,418	$ 22.33
Granted (D)	122,044	$ 24.18
Vested (E)	(124,886)	$ 21.56
Forfeited	(66,314)	$ 23.25
Units Non-Vested at 12/31/07 (F)	238,262	$ 23.42

(D) Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.
(E) These performance units, which were awarded in 2005 and became fully vested at December 31, 2007, were certified by the Compensation Committee of the Company's Board of Directors in February 2008.
(F) Of the 238,262 performance units not vested at December 31, 2007, 216,023 performance units are assumed to vest at the end of the applicable vesting period.

At December 31, 2007, there was approximately $2.3 million in unrecognized compensation cost related to non-vested performance units based on TSR which is expected to be recognized over a weighted-average period of 1.56 years.

Performance Units – Earnings Per Share

The Company recorded compensation expense of approximately $1.5 million pre-tax ($0.9 million after tax), $2.0 million pre-tax ($1.2 million after tax) and $0.5 million pre-tax ($0.3 million after tax), in 2007, 2006 and 2005, respectively, related to the performance units based on EPS. The fair value of the performance units based on EPS is based on grant date fair value which is equivalent to the price of one share of the Company's common stock on the date of grant. The fair value of performance units based on EPS varies as the number of performance units that will vest is based on the grant date fair value of the units and the probable outcome of the performance condition. The Company reassesses at each reporting date whether achievement of the performance condition is probable and accrues compensation expense if and when achievement of the performance condition is probable. As a result, the compensation expense recognized for these performance units can vary from period to period. There are no post-vesting restrictions related to the Company's performance units based on EPS. The grant date fair value of the 2005, 2006 and 2007 performance units was $23.78, $28.00 and $33.59, respectively.

A summary of the activity for the Company's performance units based on EPS at December 31, 2007 and changes during 2007 are summarized in the following table. Following the end of a three-year performance period, payout of the performance units based on EPS growth is determined by the Company's growth in EPS for such period compared to a target set at the beginning of the three-year period by the Compensation Committee of the Company's Board of Directors and payout requires the approval of the Compensation Committee. Payouts, if any, are made in two-thirds stock and one-third cash (other than payouts of performance units awarded in 2006 and 2007, which will be made only in common stock) and are considered made when approved by the Compensation Committee.

(dollars in millions)	Number of Units	Stock Conversion Ratio (A)	Aggregate Intrinsic Value
Units Outstanding at 12/31/06	102,459	1:1	
Granted (B)	40,686	1:1	
Forfeited	(22,163)	1:1	
Units Outstanding at 12/31/07	120,982	1:1	$ 7.6
Units Fully Vested at 12/31/07 (C)	41,618	1:1	$ 3.0

(A) One performance unit = one share of the Company's common stock
(B) Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.
(C) These performance units, which were awarded in 2005 and became fully vested at December 31, 2007, were certified by the Compensation Committee of the Company's Board of Directors in February 2008.

A summary of the activity for the Company's non-vested performance units based on EPS at December 31, 2007 and changes during 2007 are summarized in the following table:

	Number of Units	Weighted-Average Grant Date Fair Value
Units Non-Vested at 12/31/06	102,459	$ 26.15
Granted (D)	40,686	$ 33.59
Vested (E)	(41,618)	$ 23.78
Forfeited	(22,163)	$ 29.72
Units Non-Vested at 12/31/07 (F)	79,364	$ 30.21

(D) Represents target number of units granted. Actual number of units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.
(E) These performance units, which were awarded in 2005 and became fully vested at December 31, 2007, were certified by the Compensation Committee of the Company's Board of Directors in February 2008.
(F) Of the 79,364 performance units not vested at December 31, 2007, 72,008 performance units are assumed to vest at the end of the applicable vesting period.

At December 31, 2007, there was approximately $0.8 million in unrecognized compensation cost related to non-vested performance units based on EPS which is expected to be recognized over a weighted-average period of 1.00 years.

Stock Options

The Company recorded no compensation expense in 2007 related to stock options because at December 31, 2006, there was no unrecognized compensation cost related to non-vested options, which became fully vested in January 2007. The Company recorded compensation expense of approximately $0.1 million pre-tax (less than $0.1 million after tax) in 2006 related to stock options. No compensation expense related to stock options was recognized in 2005 as all options granted under the Plans had an exercise price equal to the market value of the Company's common stock on the grant date.

A summary of the activity for the Company's options at December 31, 2007 and changes during 2007 are summarized in the following table:

(dollars in millions)	Number of Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value	Weighted-Average Remaining Contractual Term
Options Outstanding at 12/31/06	1,485,602	$ 21.90		
Exercised	(346,674)	$ 23.74	$ 4.9	
Expired	(11)	$ 16.69		
Options Outstanding at 12/31/07	1,138,917	$ 21.34	$ 17.0	4.28 years
Options Fully Vested and Exercisable at 12/31/07	1,138,917	$ 21.34	$ 17.0	4.28 years

A summary of the activity for the Company's non-vested options at December 31, 2007 and changes during 2007 are summarized in the following table:

	Number of Options	Weighted-Average Grant Date Fair Value
Options Non-Vested at 12/31/06	91,382	$ 2.05
Vested	(91,382)	$ 2.05
Options Non-Vested at 12/31/07	---	$ ---

5. Loss on Retirement and Asset Retirement Obligation of Fixed Assets

OG&E had a power supply contract with a large industrial customer that expired on June 1, 2006. OG&E evaluated options to utilize the assets dedicated to that customer and decided to retire these assets as of June 30, 2006. The carrying amount of these assets at June 30, 2006 was approximately $6.8 million, which was recorded as a pre-tax loss during the second quarter of 2006. This loss was included in Other Expense in the Consolidated Statement of Income. Also, as part of the settlement of the ARO for these assets, OG&E recorded a reduction to the previously recorded ARO for these assets of approximately $0.9 million in 2006 due to an agreement with a third party to provide removal and remediation services. This reduction is included in Other Expense in the Consolidated Statement of Income.

6. 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 2007 and 2006, the Company's use of non-trading price risk management instruments involved the use of commodity price futures, commodity price swap contracts, commodity price option features and treasury lock agreements. The commodity price futures and commodity price swap contracts involved the exchange of fixed price or rate payments for floating price or rate payments over the life of the instrument without an exchange of the underlying commodity. The commodity price option contracts involved the payment of a premium for the right, but not the obligation, to exchange fixed price or rate payments for floating price or rate payments over the life of the instrument without an exchange of the underlying commodity. The treasury lock agreements help protect against the variability of future interest payments of long-term debt that was issued by OG&E.

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 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 Other Current Assets in the Consolidated Balance Sheets. 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 transaction 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 measures the ineffectiveness of commodity cash flow hedges using the change in fair value method prescribed by SFAS No. 133. Under the change in fair value method, the change in the expected future cash flows designated as the hedge transaction are compared to the change in fair value of the hedging instrument. The ineffectiveness of treasury lock cash flow hedges is measured using the hypothetical derivative method prescribed by SFAS No. 133. Under the hypothetical derivative method, the Company designates 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.

Management 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. Management applies normal purchases and normal sales to: (i) commodity contracts for the purchase and sale of natural gas; (ii) commodity contracts for the sale of natural gas liquids produced by its subsidiary, Enogex Products Corporation ("Products"); (iii) electric power contracts by OG&E; and (iv) fuel procurement by OG&E.

At December 31, 2007, OG&E's treasury lock agreements were not designated as cash flow hedges under SFAS No. 133. The 2007 treasury lock agreements were settled on January 29, 2008. At December 31, 2006, OG&E's treasury lock agreements were designated as cash flow hedges under SFAS No. 133. The 2006 treasury lock agreements expired March 29, 2007.

Trading Activities

The Company, through 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 Price Risk Management Liabilities in the Consolidated Balance Sheets, classified as current or long-term based on their anticipated settlement, or against the brokerage deposits in Other Current Assets. The offsetting 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 or in Other

Comprehensive Income for derivatives designated and qualifying as cash flow hedges in accordance with SFAS No. 133. 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.

In the second quarter of 2007, the Company adopted FASB Interpretation No. 39 (As Amended), “Offsetting of Amounts Related to Certain Contracts – an interpretation of APB Opinion No. 10 and FASB Statement No. 105,” which states that fair value amounts recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity’s choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, currency swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Consolidated Balance Sheet. The Company has presented the fair values of its contracts under master netting agreements using a net fair value presentation. If these transactions with the same counterparty were presented on a gross basis in the Consolidated Balance Sheets, current Price Risk Management assets and liabilities would be approximately $10.0 million and $51.4 million, respectively, at December 31, 2007, and non-current Price Risk Management assets and liabilities would be approximately $2.6 million and $38.9 million, respectively, at December 31, 2007. If these transactions with the same counterparty were presented on a gross basis in the Consolidated Balance Sheets, current Price Risk Management assets and liabilities would be approximately $41.9 million and $9.2 million, respectively, at December 31, 2006, and non-current Price Risk Management assets and liabilities would be approximately $1.7 million and $1.1 million, respectively, at December 31, 2006.

7. Enogex – Discontinued Operations

In May 2006, Enogex’s wholly owned subsidiary, Enogex Gas Gathering, L.L.C. (“Gathering”), sold certain gas gathering assets in the Kinta, Oklahoma area (the “Kinta Assets”), which included approximately 568 miles of gathering pipeline and 22 compressor units, for approximately $92.9 million. Enogex recorded an after tax gain of approximately $34.1 million from this sale in the second quarter of 2006.

In October 2005, Enogex sold its interest in Enogex Arkansas Pipeline Corporation (“EAPC”), which held a 75 percent interest in the NOARK Pipeline System Limited Partnership, for approximately $177.4 million. Enogex recorded an after tax gain of approximately $36.7 million from this sale in the fourth quarter of 2005.

In August 2005, Enogex Compression Company, LLC (“Enogex Compression”) sold its interest in Enerven Compression Services, LLC (“Enerven”), a joint venture focused on the rental of natural gas compression assets, for approximately $7.3 million. Enogex Compression recognized an after tax gain of approximately $1.8 million from this sale in the third quarter of 2005.

The Consolidated Financial Statements of the Company have been reclassified to reflect the above sales as discontinued operations. Accordingly, revenues, costs and expenses and cash flows from these sales 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. As the above sales occurred prior to 2007, there are no results of operations for discontinued operations during 2007. Summarized financial information for the discontinued operations as of December 31 is as follows:

CONSOLIDATED STATEMENTS OF INCOME DATA

Year ended December 31 *(In millions)*	**2007**	2006	2005
Operating revenues from discontinued operations	**$** ---	$ 9.4	$ 106.0
Income from discontinued operations before taxes	---	59.1	84.2

8. 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)*	**2007**	2006	2005
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Change in fair value of long-term debt due to interest rate swaps	**$ ---**	$ ---	$ (7.8)
Power plant long-term service agreement	**0.7**	---	---
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash Paid During the Period for			
Interest (net of interest capitalized of $4.9, $5.4, $2.2)	**$ 93.5**	$ 85.5	$ 95.9
Income taxes (net of income tax refunds)	**86.6**	122.7	42.0

9. Income Taxes

The items comprising income tax expense are as follows:

Year ended December 31 *(In millions)*	**2007**	2006	2005
Provision (Benefit) for Current Income Taxes from Continuing Operations			
Federal	**$ 96.0**	$ 96.0	$ 43.0
State	**3.9**	(7.4)	5.0
Total Provision for Current Income Taxes from Continuing Operations	**99.9**	88.6	48.0
Provision for Deferred Income Taxes, net from Continuing Operations			
Federal	**18.2**	35.4	26.4
State	**2.7**	1.9	---
Total Provision for Deferred Income Taxes, net from Continuing Operations	**20.9**	37.3	26.4
Deferred Federal Investment Tax Credits, net	**(4.8)**	(5.0)	(5.1)
Income Taxes Relating to Other Income and Deductions	**0.7**	(0.4)	(0.7)
Total Income Tax Expense from Continuing Operations	**$ 116.7**	$ 120.5	$ 68.6

The Company files consolidated income tax returns in the U.S. federal jurisdiction and various state jurisdictions. With few exceptions, the Company is no longer subject to U.S. Federal or state and local income tax examinations by tax authorities for years before 2002. Income taxes are generally allocated to each company in the affiliated group based on its separate taxable income or loss. Federal investment tax credits previously claimed on electric utility property have been deferred and are being amortized to income over the life of the related property. The Company continues to amortize its federal investment tax credits on a ratable basis throughout the year. This ratable amortization results in a larger percentage reconciling item related to these credits during the first quarter when the Company historically experiences decreased book income. The following schedule reconciles the statutory federal tax rate to the effective income tax rate:

Year ended December 31	**2007**	2006	2005
Statutory federal tax rate	**35.0%**	35.0%	35.0%
State income taxes, net of federal income tax benefit	1.9	2.8	1.5
Amortization of net unfunded deferred taxes	0.8	0.7	1.0
Medicare Part D subsidy	(0.3)	(0.7)	(1.2)
401(k) dividends	(1.2)	(0.9)	(1.8)
Federal investment tax credits, net	(1.3)	(1.4)	(2.2)
Federal renewable energy credit (A)	(2.0)	---	---
Excess deferred taxes (B)	---	---	(2.3)
Other	(0.6)	(0.7)	(0.1)
Effective income tax rate as reported	**32.3%**	34.8%	29.9%

(A) These are credits OG&E began earning associated with the production from its 120 MW wind farm in northwestern Oklahoma (“Centennial”) that was placed in service during January 2007.
(B) 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 2.3 percent.

In connection with the filing of the Company's 2002 consolidated income tax returns, OG&E elected to change its tax method of accounting related to the capitalization of costs for self-constructed assets to another method prescribed in the Income Tax regulations. The accounting method change was for income tax purposes only. For financial accounting purposes, the only change was recognition of the impact of the cash flow generated by accelerating income tax deductions. This was 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 were refunded. 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. In the Company's IRS examination for years 2002 and 2003, the IRS stated that it disagreed with the change made by OG&E.

The Company adopted the provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109," on January 1, 2007. As a result of the implementation of FIN No. 48, the Company recognized an approximate $6.2 million increase in the accrued interest liability. The after-tax effect, of approximately $3.8 million, was accounted for as a reduction to the January 1, 2007 balance of retained earnings. The balance of uncertain tax positions at January 1, 2007 consisted of approximately $171.6 million of tax positions associated with the capitalization of costs for self-constructed assets discussed above. Because of the impact of deferred tax accounting, other than interest and penalties, the disallowance of the shorter deductibility period would not affect the annual effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period. OG&E reached a final settlement with the IRS on November 27, 2007 related to the tax method of accounting for the capitalization of costs for self-constructed assets. A reconciliation of the beginning and ending amounts of unrecognized tax benefits is as follows:

(In millions)		
Balance at January 1, 2007	$	66.4
Settlements with tax authorities		(66.4)
Balance at December 31, 2007	$	---

The Company recognizes accrued interest related to tax benefits in interest expense and recognizes penalties in other expense. OG&E recorded interest expense associated with the IRS audit of approximately $3.3 million in 2005, $0.3 million in 2006 and $2.6 million through October 2007. On November 27, 2007, OG&E reached a final settlement with the IRS related to the tax method of accounting, which resulted in the reversal of approximately $9.5 million of previously accrued interest expense related to this previously uncertain tax position. At December 31, 2007, the Company had approximately $2.9 million of accrued interest related to the capitalization of costs for self-constructed assets discussed above.

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, 2007 and 2006, respectively, were as follows:

December 31 *(In millions)*	**2007**	2006
Current Accumulated Deferred Tax Assets		
Derivative instruments	$ **19.3**	$ ---
Accrued vacation	**6.4**	6.2
Accrued liabilities	**6.3**	3.4
Uncollectible accounts	**1.6**	1.7
Other	**4.5**	2.6
Total Current Accumulated Deferred Tax Assets	**38.1**	13.9
Current Accumulated Deferred Tax Liabilities		
Derivative instruments	---	(3.3)
Current Accumulated Deferred Tax Assets, net	$ **38.1**	$ 10.6
Non-Current Accumulated Deferred Tax Liabilities		
Accelerated depreciation and other property related differences	$ **780.3**	$ 793.7
Regulatory asset	**96.0**	75.9
Company pension plan	**60.6**	41.4
Income taxes refundable to customers, net	**6.7**	13.0
Bond redemption-unamortized costs	**6.1**	6.4
Total Non-Current Accumulated Deferred Tax Liabilities	**949.7**	930.4
Non-Current Accumulated Deferred Tax Assets		
Regulatory liabilities	**(34.3)**	(29.1)
Postretirement medical and life insurance benefits	**(34.3)**	(30.8)
Derivative instruments	**(18.9)**	---
Deferred federal investment tax credits	**(8.5)**	(10.4)
Other	**(0.1)**	(0.9)
Total Non-Current Accumulated Deferred Tax Assets	**(96.1)**	(71.2)
Non-Current Accumulated Deferred Income Tax Liabilities, net	$ **853.6**	$ 859.2

The Company fully utilized all of its Oklahoma investment tax credit carryovers from 2006 and prior periods in 2007. During 2007, additional Oklahoma tax credits of approximately $14.2 million were generated or purchased by the Company. The Company currently believes that approximately $9.7 million of these state tax credit amounts will be utilized in 2007 and approximately $4.5 million will be carried over to 2008 and later years. Credits not utilized in 2007 will begin expiring in 2018.

10. Common Stock

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 years ended December 31, 2007, 2006 and 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.

At December 31, 2007, there were 11,805,879 shares of unissued common stock reserved for issuance under 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 confronted with an unfair or inadequate acquisition proposal. In connection with a 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 outstanding 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.

11. Earnings Per Share

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

Year ended December 31 *(In millions)*	**2007**	2006	2005
Average Common Shares Outstanding			
Basic average common shares outstanding	**91.7**	91.0	90.3
Effect of dilutive securities:			
Employee stock options and unvested stock grants	**0.3**	0.3	0.2
Contingently issuable shares (performance units)	**0.5**	0.8	0.3
Diluted average common shares outstanding	**92.5**	92.1	90.8
Anti-dilutive shares excluded from EPS calculation	---	0.1	0.2

12. Long-Term Debt

A summary of the Company's long-term debt is included in the Consolidated Statements of Capitalization. At December 31, 2007, the Company was in compliance with all of its debt agreements**.**

Optional Redemption of Long-Term Debt

OG&E's $125.0 million principal amount 6.65 percent Senior Notes ("Senior Notes") due July 15, 2027, included a one-time option of the holders to redeem the notes on July 15, 2007, at 100 percent of the principal amount with accrued and unpaid interest. In July 2007, $50,000 of the Senior Notes were redeemed by the holders and retired.

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
3.25% - 4.07%	Garfield Industrial Authority, January 1, 2025	**$ 47.0**
3.24% - 4.03%	Muskogee Industrial Authority, January 1, 2025	**32.4**
3.35% - 4.11%	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 believes that it has sufficient long-term liquidity to meet these obligations.

Long-Term Debt Maturities

Maturities of the Company's long-term debt during the next five years consist of $1.0 million in 2008 and $400.0 million in 2010. There are no maturities of the Company's long-term debt in years 2009, 2011 or 2012.

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.

Issuance of New Long-Term Debt

In January 2008, OG&E issued $200.0 million of 6.45% senior notes due February 1, 2038. The proceeds from the issuance were used to repay commercial paper borrowings. OG&E entered into two separate treasury lock arrangements, effective November 16, 2007 and November 19, 2007, to hedge interest payments on the first $50.0 million and $25.0 million, respectively, of the long-term debt that was issued in January 2008. These treasury lock agreements were settled on January 29, 2008.

13. 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 $295.8 million at December 31, 2007 at a weighted-average interest rate of 5.54 percent. There was no short-term debt outstanding at December 31, 2006. The following table shows the Company’s revolving credit agreements and available cash at December 31, 2007.

Revolving Credit Agreements and Available Cash *(In millions)*

Entity	Amount Available	Amount Outstanding	Weighted-Average Interest Rate	Maturity
OGE Energy Corp. (A)	$ 600.0	$ 295.0	5.54%	December 6, 2012 (C)
OG&E (B)	400.0	---	---	December 6, 2012 (C)
	1,000.0	295.0	5.54%	
Cash	8.8	N/A	N/A	N/A
Total	$ 1,008.8	$ 295.0	5.54%	

(A) This bank facility is available to back up the Company’s commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility. At December 31, 2007, there was approximately $295.0 million in outstanding commercial paper borrowings.
(B) This bank facility is available to back up OG&E’s commercial paper borrowings and to provide revolving credit borrowings. At December 31, 2007, OG&E had outstanding approximately $3.1 million supporting letters of credit and no commercial paper borrowings.
(C) In December 2006, the Company and OG&E amended and restated their revolving credit agreements to total in the aggregate $1.0 billion, $600 million for the Company and $400 million for OG&E. Each of the credit facilities has a five-year term with an option to extend the term for two additional one-year periods. In November 2007, the Company and OG&E utilized one of these one-year extensions to extend the maturity of their credit agreements to December 6, 2012. Also, each of these credit facilities has an additional option at the end of the two renewal options to convert the outstanding balance to a one-year term loan.

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 disruption as experienced with the market turmoil in August 2007. As a result of the market turmoil in August 2007, the Company and OG&E utilized borrowings under their revolving credit agreements. During the third and fourth quarters of 2007, the Company and OG&E repaid the borrowings under their revolving credit agreements and began utilizing commercial paper in the commercial paper market. 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 of the Company 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. Any future downgrade of the Company would also lead to higher long-term borrowing costs and, if below investment grade, would require the Company to post cash collateral or letters of credit. Also, any downgrade below investment grade at OERI could require the Company to issue guarantees to support some of OERI’s marketing operations.

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 $800 million in short-term borrowings at any one time for a two-year period beginning January 1, 2007 and ending December 31, 2008.

14. Retirement Plans and Postretirement Benefit Plans

In September 2006, the FASB issued SFAS No. 158 which required an employer to recognize the overfunded or underfunded status of a defined benefit postretirement plan (other than a multiemployer plan) as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which the changes occur through comprehensive income of a business entity. The requirement to initially recognize the funded status of the defined benefit postretirement plan and the disclosure requirements was effective for the year ended December 31, 2006 for the Company.

Defined Benefit Pension Plan

All eligible employees of the Company and participating affiliates 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, "Employers' Accounting for Pensions," pension expense as determined by the Company's actuarial consultants. Additional amounts may be contributed from time to time to increase the funded status of the plan. During 2007 and 2006, the Company made contributions to its pension plan of approximately $50.0 million and $90.0 million, respectively, to help 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. In August 2006, legislation was passed that changed the funding requirement for single- and multi-employer defined benefit pension plans as discussed below. During 2008, the Company may contribute up to $50.0 million to its pension plan. The expected contribution to the pension plan, anticipated to be in the form of cash, is a discretionary contribution and is not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended.

At December 31, 2007, the projected benefit obligation and fair value of assets of the Company's pension plan and restoration of retirement income plan was approximately $522.0 million and $514.2 million, respectively, for an underfunded status of approximately $7.8 million. These amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which is recorded as a regulatory asset as discussed in Note 1) in the Company's Consolidated Balance Sheet. The amounts in Accumulated Other Comprehensive Loss and as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

At December 31, 2006, the projected benefit obligation and fair value of assets of the Company's pension plan and restoration of retirement income plan was approximately $585.0 million and $519.4 million, respectively, for an underfunded status of approximately $65.6 million. These amounts were recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which was recorded as a regulatory asset as discussed in Note 1) in the Company's Consolidated Balance Sheet. The entry did not impact the results of operations in 2006 and did not require a usage of cash and is therefore excluded from the Consolidated Statement of Cash Flows. The amounts in Accumulated Other Comprehensive Loss and as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

In accordance with SFAS No. 88, "Employer's Accounting for Settlements and Curtailments of Defined Benefit Pension Plans and for Termination Benefits," a one-time settlement charge is required to be recorded by an organization when lump-sum payments or other settlements that relieve the organization from the responsibility for the pension benefit obligation or the retirement restoration benefit obligation during a plan year exceed the service cost and interest cost components of the organization's net periodic pension cost or retirement restoration cost. During 2007 and 2006, the Company experienced an increase in both the number of employees electing to retire and the amount of lump-sum payments to be paid to such employees upon retirement as well as the death of the Company's Chairman and Chief Executive Officer in September 2007. As a result, the Company recorded pension settlement charges in 2007 and 2006 and a retirement restoration plan settlement charge in 2007. The pension settlement charges and retirement restoration plan settlement charge did not require a cash outlay by the Company and did not increase the Company's total pension expense or retirement restoration expense over time, as the charges were an acceleration of costs that otherwise would have been recognized as pension expense or retirement restoration expense in future periods.

(In millions)	OG&E (A)	Enogex	OGE Energy	Total
Pension Settlement Charges:				
2007	**$ 13.3**	**$ 0.5**	**$ 2.9**	**$ 16.7**
2006	$ 13.3	$ 0.8	$ 3.0	$ 17.1
Retirement Restoration Plan Settlement Charge:				
2007	**$ 0.1**	**$ ---**	**$ 2.2**	**$ 2.3**

(A) OG&E's Oklahoma jurisdictional portion of these charges were recorded as a regulatory asset (see Note 1 for a further discussion).

Pension Plan Costs and Assumptions

On August 17, 2006, President Bush signed The Pension Protection Act of 2006 (the "Pension Protection Act") into law. The Pension Protection Act makes changes to important aspects of qualified retirement plans. Among other things, it introduces a new funding requirement for single- and multi-employer defined benefit pension plans, provides legal certainty on a prospective basis for cash balance and other hybrid plans and addresses contributions to defined contribution plans, deduction limits for contributions to retirement plans and investment advice provided to plan participants.

Many of the changes enacted as part of the Pension Protection Act are required to be implemented as of the first plan year beginning in 2008. While the Company generally has until the last day of the first plan year beginning in 2009 to reflect those changes as part of the plan document, plans must nevertheless comply in operation as of each provision's effective date. The Company is taking steps now to ensure that its plans, as well as participants and outside administrators, are aware of the changes. In some instances, changes will necessitate notices to participants and/or changes in the plan's administrative forms.

Plan Investments, Policies and Strategies

The pension 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, 2007 and 2006:

December 31	**2007**	2006
Equity securities	**61 %**	64 %
Debt securities	**37 %**	34 %
Other	**2 %**	2 %
Total	**100 %**	100 %

The pension 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 Investment Committee (the "Investment Committee").

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

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

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

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

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

The fixed income manager is expected to use discretion over the asset mix of the trust assets in its efforts to maximize risk-adjusted performance. Exposure to any single issuer, other than the U.S. government, its agencies, or its instrumentalities (which have no limits) is limited to five percent of the fixed income portfolio as measured by market value. At least 75 percent of the invested assets must possess an investment grade rating at or above Baa3 or BBB- by Moody's Investors Service ("Moody's"), Standard & Poor's Ratings Services ("Standard & Poor's") or Fitch Ratings ("Fitch"). The portfolio may invest up to 10 percent of the portfolio's market value in convertible bonds as long as the securities purchased meet the quality guidelines. The purchase of any of 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 than 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 Investment 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 Internal Revenue Code (the "Code"). The benefits payable under this restoration of retirement income plan are equivalent to the amounts that would have been payable under the pension plan but for these limitations. The restoration of retirement income plan is intended to be an unfunded plan.

The Company expects to pay benefits related to its pension plan and restoration of retirement income plan of approximately $57.9 million in 2008, $58.9 million in 2009, $59.4 million in 2010, $62.5 million in 2011, $63.9 million in 2012 and an aggregate of approximately $289.7 million in years 2013 to 2017. These expected benefits are 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.

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 postretirement medical benefits while employees hired on or after February 1, 2000, are not entitled to postretirement medical benefits. All regular, full-time, active employees whose age and years of credited service total or exceed 80 or have attained age 55 with five years of vesting service at the time of retirement 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.

At December 31, 2007, the accumulated postretirement benefit obligation and fair value of assets of the Company's postretirement benefit plans was approximately $216.8 million and $78.5 million, respectively, for an underfunded status of approximately $138.3 million. These amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which is recorded as a regulatory asset as discussed in Note 1) in the Company's Consolidated Balance Sheet. The amount in Accumulated Other Comprehensive Loss and as a regulatory asset represents a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

At December 31, 2006, the accumulated postretirement benefit obligation and fair value of assets of the Company's postretirement benefit plans was approximately $225.4 million and $74.0 million, respectively, for an underfunded status of approximately $151.4 million. These amounts were recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which was recorded as a regulatory asset as discussed in Note 1) in the Company's Consolidated Balance Sheet. The entry did not impact the results of operations in 2006 and did not require a usage of cash and is therefore excluded from the Consolidated Statement of Cash Flows. The amount in Accumulated Other Comprehensive Loss and as a regulatory asset represents a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

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 9.0 percent in 2008 with the rates decreasing in subsequent years by one percentage point per year through 2011. A one-percentage point change in the assumed health care cost trend rate would have the following effects:

ONE-PERCENTAGE POINT INCREASE

Year ended December 31 *(In millions)*	**2007**	2006	2005
Effect on aggregate of the service and interest cost components	**$ 2.3**	$ 2.2	$ 1.8
Effect on accumulated postretirement benefit obligations	**26.9**	29.2	26.9

ONE-PERCENTAGE POINT DECREASE

Year ended December 31 *(In millions)*	**2007**	2006	2005
Effect on aggregate of the service and interest cost components	**$ 1.9**	$ 1.8	$ 1.5
Effect on accumulated postretirement benefit obligations	**22.2**	24.0	22.0

Medicare Prescription Drug, Improvement and Modernization Act of 2003

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the "Medicare Act"). The Medicare Act expanded Medicare to include, for the first time, coverage for prescription drugs. 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 provided 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 required 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 with respect to its postretirement medical plan will be reduced by approximately $39.8 million as a result of savings to the Company with respect to its postretirement medical plan resulting from the Medicare Act provided subsidy, which will reduce the Company's costs for its postretirement medical plan by approximately $5.5 million annually. The $5.5 million in annual savings is comprised of a reduction of approximately $2.6 million from amortization of the $39.8 million gain due to the reduction of the APBO, a reduction in the interest cost on the APBO of approximately $2.3 million and a reduction in the service cost due to the subsidy of approximately $0.6 million.

The Company expects to pay gross benefits payments related to its postretirement benefit plans, including prescription drug benefits, of approximately $11.9 million in 2008, $13.0 million in 2009, $14.1 million in 2010, $15.2 million in 2011, $16.1 million in 2012 and an aggregate of approximately $92.3 million in years 2013 to 2017. The Company expects to receive federal subsidy receipts provided by the Medicare Act of approximately $1.3 million in 2008, $1.5 million in 2009, $1.6 million in 2010, $1.8 million in 2011, $1.9 million in 2012 and an aggregate of approximately $11.6 million in years 2013 to 2017. The Company received approximately $1.9 million in federal subsidy receipts in 2007.

Obligations and Funded Status

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:

	Pension Plan		Restoration of Retirement Income Plan		Postretirement Benefit Plans	
December 31 *(In millions)*	**2007**	2006	**2007**	2006	**2007**	2006
Change in Benefit Obligation						
Beginning obligations	**$ (575.2)**	$ (584.4)	**$ (9.8)**	$ (9.6)	**$ (225.4)**	$ (208.2)
Service cost	**(20.6)**	(19.7)	**(0.6)**	(0.7)	**(4.0)**	(3.7)
Interest cost	**(31.8)**	(30.3)	**(0.5)**	(0.5)	**(12.4)**	(11.9)
Plan changes	**16.7**	---	**0.1**	---	**---**	---
Participants' contributions	**---**	---	**---**	---	**(5.5)**	(5.0)
Actuarial gains (losses)	**15.4**	(15.5)	**(1.4)**	0.6	**15.2**	(12.1)
Benefits paid	**77.5**	74.7	**8.2**	0.4	**15.3**	15.5
Ending obligations	**(518.0)**	(575.2)	**(4.0)**	(9.8)	**(216.8)**	(225.4)
Change in Plans' Assets						
Beginning fair value	**519.4**	439.4	**---**	---	**74.0**	67.2
Actual return on plans' assets	**22.3**	64.7	**---**	---	**5.6**	8.4
Employer contributions	**50.0**	90.0	**8.2**	0.4	**8.7**	8.9
Participants' contributions	**---**	---	**---**	---	**5.5**	5.0
Benefits paid	**(77.5)**	(74.7)	**(8.2)**	(0.4)	**(15.3)**	(15.5)
Ending fair value	**514.2**	519.4	**---**	---	**78.5**	74.0
Funded status at end of year	**$ (3.8)**	$ (55.8)	**$ (4.0)**	$ (9.8)	**$ (138.3)**	$ (151.4)

Net Periodic Benefit Cost

Year ended December 31 *(In millions)*	Pension Plan **2007**	Pension Plan 2006	Pension Plan 2005	Restoration of Retirement Income Plan **2007**	Restoration of Retirement Income Plan 2006	Restoration of Retirement Income Plan 2005	Postretirement Benefit Plans **2007**	Postretirement Benefit Plans 2006	Postretirement Benefit Plans 2005
Service cost	**$ 20.6**	$ 19.7	$ 18.7	**$ 0.6**	$ 0.7	$ 0.4	**$ 4.0**	$ 3.7	$ 3.2
Interest cost	**31.8**	30.3	29.8	**0.5**	0.5	0.5	**12.4**	11.9	10.5
Return on plan assets	**(43.9)**	(38.4)	(34.2)	---	---	---	**(5.9)**	(5.6)	(5.5)
Amortization of transition obligation	---	---	---	---	---	---	**2.7**	2.7	2.7
Amortization of net loss	**10.5**	16.5	14.4	**0.2**	0.2	0.3	**6.1**	8.7	5.0
Amortization of recognized prior service cost	**5.2**	5.2	5.7	**0.6**	0.7	0.6	**2.1**	2.1	2.1
Settlement	**16.7**	17.1	---	**2.3**	---	---	---	---	---
Net periodic benefit cost (A)	**$ 40.9**	$ 50.4	$ 34.4	**$ 4.2**	$ 2.1	$ 1.8	**$ 21.4**	$ 23.5	$ 18.0

(A) Approximately $10.1 million of the net periodic benefit cost relates to OG&E's Oklahoma jurisdictional portion, which has been recorded as a regulatory asset (see Note 1 for a further discussion). The capitalized portion of the net periodic pension benefit cost was approximately $5.5 million, $7.6 million and $9.3 million at December 31, 2007, 2006 and 2005, respectively. The capitalized portion of the net periodic postretirement benefit cost was approximately $4.8 million, $5.0 million and $4.7 million at December 31, 2007, 2006 and 2005, respectively.

Rate Assumptions

Year ended December 31	Pension Plan and Restoration of Retirement Income Plan **2007**	2006	2005	Postretirement Benefit Plans **2007**	2006	2005
Discount rate	**6.25%**	5.75%	5.50%	**6.25%**	5.75%	5.50%
Rate of return on plans' assets	**8.50%**	8.50%	8.50%	**8.50%**	8.50%	8.50%
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%**	9.00%	9.00%
Ultimate trend rate	**N/A**	N/A	N/A	**4.50%**	4.50%	4.50%
Ultimate trend year	**N/A**	N/A	N/A	**2013**	2012	2011

N/A - not applicable

The overall expected rate of return on plan assets assumption remained at 8.50 percent in 2006 and 2007 in determining net periodic benefit 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.

Post-Employment Benefit Plan

Disabled employees receiving benefits from the Company's Group Long-Term Disability Plan are entitled to continue participating in the Company's Medical Plan along with their dependents. The post-employment benefit obligation represents the actuarial present value of estimated future medical benefits that are attributed to employee service rendered prior to the date as of which such information is presented. The obligation also includes future medical benefits expected to be paid to current employees participating in the Company's Group Long-Term Disability Plan and their dependents, as defined in the Company's Medical Plan.

The post-employment benefit obligation is determined by an actuary on a basis similar to the accumulated postretirement benefit obligation. The estimated future medical benefits are projected to grow with expected future medical cost trend rates and are discounted for interest at the discount rate and for the probability that the participant will discontinue receiving benefits from the Company's Group Long-Term Disability Plan due to death, recovery from disability, or eligibility for retiree medical benefits. The Company's post-employment benefit obligation was approximately $1.6 million and $2.0 million at December 31, 2007 and 2006, respectively.

Defined Contribution Plan

The Company provides a defined contribution savings plan. Each regular full-time employee of the Company or a participating affiliate is eligible to participate in the plan immediately. All other employees of the Company or a participating 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." Participants who have attained age 50 before the close of a year are allowed to make additional contributions referred to as "Catch-Up Contributions," subject to the limitations of the Code. 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 contributes 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, Catch-Up 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 initially 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. Once made, the Company's contribution may be reallocated, at any time, by participants to other available investment options. The Company contributed approximately $7.6 million, $6.8 million and $6.7 million during 2007, 2006 and 2005, 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 as well as offering this plan to be competitive in the marketplace.

Eligible employees who enroll in the plan have the following deferral options: (i) eligible employees may elect to defer up to a maximum of 70 percent of base salary and 100 percent of bonus awards; or (ii) eligible employees may 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 qualified 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 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.

15. Report of Business Segments

Historically, the Company's business was divided into two reportable segments, electric utility and natural gas pipeline. As part of the process of preparing the registration statement on Form S-1 for the Partnership that was filed on June 27, 2007 and as discussed in Note 1, the Company determined that, for reporting purposes, Enogex, as a stand-alone entity, has historically had three segments – (i) natural gas transportation and storage, (ii) natural gas gathering and processing and (iii) natural gas marketing. Beginning with the second quarter of 2007, the Company's business is now divided into four reportable segments for reporting purposes. These segments are as follows: (i) electric utility, which is engaged in the generation, transmission, distribution and sale of electric energy, (ii) natural gas transportation and storage, (iii) natural gas gathering and processing and (iv) natural gas marketing. As discussed in Note 1, on January 1, 2008, Enogex distributed the stock of OERI, which engages in the marketing of natural gas, to OGE Energy. Other Operations for the years ended December 31, 2007 and 2006 primarily included consolidating eliminations. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. In reviewing its segment operating results, the Company focuses on operating income as its measure of segment profit and loss, and therefore has presented this information below. The following tables summarize the results of the Company's business segments for the years ended December 31, 2007, 2006 and 2005. The results of the Company's business segments have been restated for all prior periods presented to conform to the 2007 presentation.

2007	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
(In millions)							
Operating revenues	**$ 1,835.1**	**$ 230.4**	**$ 799.4**	**$ 1,537.9**	**$ ---**	**$ (605.2)**	**$ 3,797.6**
Cost of goods sold	**1,025.1**	**97.7**	**603.5**	**1,513.4**	**---**	**(605.0)**	**2,634.7**
Gross margin on revenues	**810.0**	**132.7**	**195.9**	**24.5**	**---**	**(0.2)**	**1,162.9**
Other operation and maintenance	**320.7**	**48.5**	**72.1**	**6.8**	**(11.3)**	**---**	**436.8**
Depreciation	**141.3**	**17.0**	**28.7**	**0.2**	**8.1**	**---**	**195.3**
Impairment of assets	**---**	**0.5**	**---**	**---**	**---**	**---**	**0.5**
Taxes other than income	**56.0**	**11.7**	**3.7**	**0.4**	**3.2**	**---**	**75.0**
Operating income	**$ 292.0**	**$ 55.0**	**$ 91.4**	**$ 17.1**	**$ ---**	**$ (0.2)**	**$ 455.3**
Total assets	**$ 3,874.9**	**$ 1,519.3**	**$ 931.4**	**$ 253.2**	**$ 2,297.6**	**$ (3,638.6)**	**$ 5,237.8**
Capital expenditures	**$ 377.3**	**$ 49.0**	**$ 125.0**	**$ 0.2**	**$ 14.5**	**$ (8.3)**	**$ 557.7**

2006	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
(In millions)							
Operating revenues	$ 1,745.7	$ 225.9	$ 704.3	$ 1,941.3	$ ---	$ (611.6)	$ 4,005.6
Cost of goods sold	950.0	100.3	536.7	1,927.1	---	(611.6)	2,902.5
Gross margin on revenues	795.7	125.6	167.6	14.2	---	---	1,103.1
Other operation and maintenance	316.5	41.2	59.5	9.3	(9.9)	---	416.6
Depreciation	132.2	17.9	24.2	0.2	6.9	---	181.4
Impairment of assets	---	---	0.3	---	---	---	0.3
Taxes other than income	53.1	11.8	3.8	0.4	3.0	---	72.1
Operating income	$ 293.9	$ 54.7	$ 79.8	$ 4.3	$ ---	$ ---	$ 432.7
Total assets	$ 3,589.7	$ 1,441.2	$ 843.7	$ 231.4	$ 1,968.8	$ (3,176.4)	$ 4,898.4
Capital expenditures	$ 411.1	$ 9.8	$ 57.6	$ ---	$ 8.4	$ (0.3)	$ 486.6

2005	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing (A)	Other Operations	Eliminations	Total
(In millions)							
Operating revenues	$ 1,720.7	$ 246.4	$ 644.5	$ 3,995.3	$ ---	$ (695.4)	**$** 5,911.5
Cost of goods sold	994.2	147.3	504.3	3,992.6	---	(696.1)	4,942.3
Gross margin on revenues	726.5	99.1	140.2	2.7	---	0.7	969.2
Other operation and maintenance	309.2	32.9	55.3	8.4	(10.9)	---	394.9
Depreciation	134.4	17.3	23.0	0.1	7.8	---	182.6
Taxes other than income	50.7	11.6	3.4	0.4	3.2	---	69.3
Operating income (loss)	$ 232.2	$ 37.3	$ 58.5	$ (6.2)	$ (0.1)	$ 0.7	**$** 322.4
Total assets	$ 3,255.0	$ 1,456.9	$ 729.0	$ 525.4	$ 1,963.4	$ (3,058.3)	**$** 4,871.4
Capital expenditures	$ 249.1	$ 9.2	$ 25.6	$ ---	$ 13.4	$ (0.1)	**$** 297.2

(A) In March 2005, OERI 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, OERI 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 Consolidated Statement of Income and a corresponding $7.7 million decrease in Current Price Risk Management Assets in the Consolidated Balance Sheet during the three months ended March 31, 2005.

16. Commitments and Contingencies

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:

Year ended December 31 *(In millions)*	2008	2009	2010	2011	2012	2013 and Beyond
Operating lease obligations						
OG&E railcars	$ 3.7	$ 3.7	$ 3.6	$ 34.9	$ ---	$ ---
Enogex noncancellable operating leases	1.9	1.8	1.6	1.5	0.4	---
Total operating lease obligations	$ 5.6	$ 5.5	$ 5.2	$ 36.4	$ 0.4	$ ---

Payments for operating lease obligations were approximately $6.7 million, $7.6 million and $9.7 million in 2007, 2006 and 2005, respectively.

OG&E Railcar Lease Agreement

At December 31, 2007, OG&E had a noncancellable operating lease with purchase options, covering 1,409 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 $28.8 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"). See Note 17 for discussion of a recent FERC ruling related to QF obligations. 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 had a QF contract for approximately 110 MWs that expired at the end of 2007 and was not extended by OG&E. For the AES-Shady Point, Inc. ("AES") QF contract for 320 MWs, OG&E purchases 100 percent of the electricity generated by the QF. In addition, effective September 1, 2004, OG&E entered into a new 15-year power purchase agreement for 120 MWs with Powersmith Cogeneration Project, L.P. ("PowerSmith") in which OG&E purchases 100 percent of electricity generated by PowerSmith.

During 2007, 2006 and 2005, OG&E made total payments to cogenerators of approximately $156.8 million, $162.6 million and $183.8 million, respectively, of which approximately $88.9 million, $94.9 million and $95.5 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: 2008 – $88.4 million, 2009 – $86.8 million, 2010 – $85.0 million, 2011 – $83.1 million and 2012 – $81.0 million.

Fuel Minimum Purchase Commitments

OG&E purchased necessary fuel supplies of coal and natural gas for its generating units of approximately $190.2 million, $195.1 million and $163.5 million for the years ended December 31, 2007, 2006 and 2005, respectively. OG&E has entered into purchase commitments of necessary fuel supplies of approximately: 2008 – $115.1 million, 2009 – $110.2 million, 2010 – $114.3 million, 2011 – $65.3 million, 2012 – $4.0 million and 2013 and Beyond – $19.6 million.

Natural Gas Units

In August 2007, OG&E issued a request for proposal ("RFP") for gas supply purchases for periods from November 2007 through March 2008, which accounted for approximately 15 percent of its projected 2008 natural gas requirements. The contracts resulting from this RFP are tied to various gas price market indices and will expire in 2008. Additional gas supplies to fulfill OG&E's remaining 2008 natural gas requirements will be acquired through additional RFPs in early to mid-2008, along with monthly and daily purchases, all of which are expected to be made at competitive market prices.

Purchased Power

In March 2007, OG&E issued an RFP for capacity and/or firm energy purchases for the summer periods of 2008, 2009 and/or 2010. In November 2007, OG&E signed a purchase contract with Redbud for purchases in the summer periods of 2008 and 2009. OG&E submitted notice of the contract to the OCC on January 2 and 3, 2008. Interventions and protests were due within 15 days of submission of the notice. No interventions or protests were received in this matter and OG&E considers this purchase contract to be final. The purchase contract will be terminated if the acquisition of Redbud by OG&E, the OMPA and the GRDA is completed as discussed in Note 17.

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

Cheyenne Plains Gas Pipeline Company, L.L.C. ("Cheyenne Plains") operates the Cheyenne Plains Pipeline that provides firm transportation services in Wyoming, Colorado and Kansas with a capacity of 730,000 decatherms/day ("Dth/day"). OERI entered into a Firm Transportation Service Agreement ("FTSA") with Cheyenne Plains in 2004, for 60,000 Dth/day of firm capacity on the Cheyenne Plains Pipeline. The FTSA was for a 10-year term beginning with the in-service date of the Cheyenne Plains Pipeline in March 2005 with an annual demand fee of approximately $7.4 million. Effective March 1, 2007, OERI and Cheyenne Plains amended the FTSA to provide for OERI to turn back 20,000 Dth/day of its capacity beginning in January 2008 for the remainder of the term. OERI's new demand fee obligations, net of this turn back and other immaterial release agreements, are estimated at approximately $5.9 million in 2008; $6.5 million for each of the years 2009 through 2014; and $1.6 million in 2015.

Agreement with Midcontinent Express Pipeline, LLC

In December 2006, Enogex entered into a firm capacity lease agreement with Midcontinent Express Pipeline, LLC ("MEP") for a primary term of 10 years (subject to possible extension) that would give MEP and its shippers access to capacity on Enogex's system. The quantity of capacity subject to the MEP lease agreement is currently 275 million cubic feet per day, with the quantity ultimately to be leased subject to being increased by mutual agreement pursuant to the lease agreement. In addition to MEP's lease of Enogex's capacity, the proposed MEP project includes construction by MEP of a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. Pending necessary regulatory approval, the MEP project is currently expected to be in service during the first quarter of 2009. Enogex currently estimates that its capital expenditures related to this project will be approximately $86 million. The lease agreement with MEP is subject to certain contingencies, including regulatory approval. Prior to that approval, Enogex may incur expenditures of between approximately $20 million and $40 million primarily related to commitments for materials that can be sold or used in normal operations in the event the MEP project does not proceed. The amount not recovered or utilized for such expenditures is not expected to be material.

MEP filed an application with the FERC on October 9, 2007 requesting a certificate of public convenience and necessity authorizing MEP to construct its pipeline and lease certain capacity from Enogex. On October 9, 2007, Enogex also filed an application with the FERC for issuance of a limited jurisdiction certificate authorizing its lease agreement with MEP. Certain Enogex shippers have filed motions to intervene in Enogex's FERC certificate proceeding, and some have protested Enogex's certificate application. Protestors have claimed that it is unduly discriminatory for Enogex to propose to lease capacity to MEP while not generally offering firm interstate transportation service, that the lease arrangement will adversely affect the availability of interruptible interstate transportation service on the Enogex system and that the lease payment specified under the MEP lease agreement is unduly preferential in MEP's favor. These protestors have urged the FERC to reject the MEP lease arrangement or to condition its acceptance on a requirement that Enogex offer existing shippers taking interruptible interstate service the opportunity to convert that service to firm service. One protestor has asked the FERC to consolidate the Enogex certificate proceeding with Enogex's Section 311 triennial rate proceeding currently pending before the FERC. While Enogex cannot predict what action the FERC may take regarding the lease agreement, Enogex believes that the proposed MEP lease arrangement is consistent with FERC policy and precedent involving similar lease arrangements.

On January 18, 2008, Enogex filed a 30-day advance notice to advise the FERC of its intended construction of the Bennington Station Facilities. In that notice, Enogex described the environmental impacts likely to be associated with construction and operation of a new 24,000 horsepower transmission compressor station and associated pipeline that Enogex proposes to construct to support its provision of pipeline capacity under its capacity leases including the lease with MEP. Enogex believes that it has complied with all applicable requirements of the FERC's regulations pertaining to an intrastate pipeline's construction of facilities under Section 311 of the Natural Gas Policy Act, as amended. The FERC did not take any action with respect to Enogex's advance notice filing and Enogex has begun construction of the Bennington Station Facilities.

Natural Gas Measurement Cases

United States of America ex rel., Jack J. Grynberg v. Enogex Inc., Enogex Services Corporation and OG&E. (U.S. 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.* (U.S. District Court for the Eastern District of Louisiana, Case No. 97-2089; U.S. District Court for the Western District of Oklahoma, Case No. 97-1009M.). On June 15, 1999, the Company was served with the 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 Federal government, alleges: (a) 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; (b) certain provisions generally found in gas purchase contracts are improper; (c) transactions by affiliated companies are not arms-length; (d) excess processing cost deduction; and (e) 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 Federal government can intervene and take over such actions from the relator. The Department of Justice, on behalf of the Federal government, decided not to intervene in this action.

The 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 U.S. District Court for the District of Wyoming.

In October 2002, the court granted the Department of Justice's motion to dismiss certain of the plaintiff's claims and issued an order dismissing the plaintiff's valuation claims against all defendants. Various procedural motions have been filed. 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 in 2005 and the special master ruled that OG&E and all Enogex parties named in these proceedings should be dismissed. This ruling was appealed to the District Court of Wyoming.

On October 20, 2006, the District Court of Wyoming ruled on Grynberg's appeal, following and confirming the recommendation of the special master dismissing all claims against Enogex Inc., Enogex Services Corp., Transok, Inc. and OG&E, for lack of subject matter jurisdiction. Judgment was entered on November 17, 2006 and Grynberg filed his notice of appeal with the District Court of Wyoming. The defendants filed motions for attorneys' fees on various bases January 8, 2007. The defendants also filed for other legal costs on December 18, 2006. A hearing on these motions was held on April 24, 2007, at which time the judge took these motions under advisement. Grynberg has also filed appeals with the Tenth Circuit Court of Appeals. In compliance with the Tenth Circuit's June 19, 2007 scheduling order, Grynberg filed appellants' opening brief on July 31, 2007 and the appellees' consolidated response briefs were filed on November 21, 2007. Also, on December 5, 2007, the Company filed a notice of its intent to file a separate response brief, which the Company filed on January 11, 2008. At this time, oral arguments are preliminarily scheduled for the week of September 22, 2008. 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, et al. v. El Paso Natural Gas Co., et al. (Price I). On September 24, 1999, various subsidiaries of the Company were served with a class action petition filed in the District Court of Stevens County, Kansas by Quinque Operating Company and other named plaintiffs alleging the mismeasurement of natural gas on non-federal lands. On April 10, 2003, the court entered an order denying class certification. On May 12, 2003, the 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 class action petition, and the court granted the motion on July 28, 2003. In its amended petition (the "Fourth Amended Petition"), OG&E and Enogex Inc. were omitted from the case but two of the Company's subsidiary entities remained as defendants. The plaintiffs' Fourth Amended Petition seeks class certification and alleges that approximately 60 defendants, including two of the Company's subsidiary entities, have improperly measured the volume of natural gas. The Fourth Amended Petition asserts theories of civil conspiracy, aiding and abetting, accounting and unjust enrichment. In their briefing on class certification, the plaintiffs seek to also allege a claim for conversion. The plaintiffs seek unspecified actual damages, attorneys' fees, costs and pre-judgment and post-judgment interest. The plaintiffs also reserved the right to seek punitive damages.

Discovery was conducted on the class certification issues, and the parties fully briefed these same issues. A hearing on class certification issues was held April 1, 2005. In May 2006, the court heard oral argument on a motion to intervene filed by Colorado Consumers Legal Foundation, which is claiming entitlement to participate in the putative class action. The court has not yet ruled on the motion to intervene.

On July 2, 2007, the court ordered the plaintiffs and defendants to file proposed findings of facts and conclusions of law on class certification by July 31, 2007. On July 31, 2007, the two subsidiary entities of the Company filed their proposed findings of fact and conclusions of law regarding conflict of law issues and the coordinated defendants filed their proposed findings of facts and conclusions of law on class certification.

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, et al. v. El Paso Natural Gas Co., et al. (Price II). On May 12, 2003, the plaintiffs (same as those in Price I above) filed a new class action petition in the District Court of Stevens County, Kansas naming the same defendants and asserting substantially identical legal and/or equitable theories as in the amended petition of the Price I case. The plaintiffs allege that the defendants mismeasured the Btu content of natural gas obtained from or measured for the plaintiffs. In their briefing on class certification, the plaintiffs seek to also allege a claim for conversion. The plaintiffs seek unspecified actual damages, attorneys' fees, costs and pre-judgment and post-judgment interest. The plaintiffs also reserved the right to seek punitive damages.

Discovery was conducted on the class certification issues, and the parties fully briefed these same issues. A hearing on class certification issues was held April 1, 2005. In May 2006, the court heard oral argument on a motion to intervene filed by Colorado Consumers Legal Foundation, which is claiming entitlement to participate in the putative class action. The court has not yet ruled on the motion to intervene.

On July 2, 2007, the court ordered the plaintiffs and defendants to file proposed findings of facts and conclusions of law on class certification by July 31, 2007. On July 31, 2007, the two subsidiary entities of the Company filed their proposed findings of fact and conclusions of law regarding conflict of law issues and the coordinated defendants filed their proposed findings of facts and conclusions of law on class certification.

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.

Farris Buser Litigation

On July 22, 2005, Enogex along with certain other unaffiliated co-defendants was 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 Enogex and its subsidiaries, 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. Enogex and its subsidiaries 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 the Enogex companies. On September 19, 2005, the co-defendants, BP America, Inc. and BP America Production Co. (collectively, "BP"), 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. On May 17, 2006, the plaintiffs filed an amended petition against Enogex and its subsidiaries. Enogex and its subsidiaries filed a motion to dismiss the amended petition on August 2, 2006. The hearing on the dismissal motion was held on November 20, 2006 and the court denied Enogex's motion. Enogex filed an answer to the amended petition and BP's cross claim on January 16, 2007. Based on Enogex's investigation to date, the Company believes these claims and cross claims in this lawsuit are without merit and intends to continue vigorously defending this case.

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)) in the United States Bankruptcy Court, Southern District of New York (the "Bankruptcy Court"). Enogex provides natural gas transportation services pursuant to long-term contracts to two Calpine-owned power generation plants in Oklahoma. Calpine is continuing to operate the plants and request services pursuant to the contracts. The total unpaid amount due to Enogex from Calpine totaled approximately $0.3 million, which was fully reserved on the Company's books.

During October 2007, Calpine and Enogex agreed to and executed amended and restated contracts extending the primary terms, reducing the volume of firm transportation and including authorized overrun charges for additional capacity utilized. As part of the agreements, approximately $0.2 million of the bankruptcy claim was paid in November 2007 and the remaining $0.1 million will be allowed as a general unsecured claim and a cure amount under the bankruptcy plan. The amended and restated contracts were presented to and approved by the Bankruptcy Court on October 19, 2007 and the order became final on October 30, 2007. The payment of the remaining claims ($0.1 million) is currently fully reserved and is expected to be paid in the first quarter of 2008.

A Calpine-owned power generation plant in Oklahoma is contractually obligated to provide capacity and energy to OG&E; however, the contract terminated on December 31, 2007. The Calpine plant also pays, through the SPP, for transmission services provided by OG&E. Whether Calpine will subsequently continue to require transmission services from OG&E is unknown.

OERI Self-Disclosure Matter

On November 13, 2007, OERI orally self-reported to the FERC Office of Enforcement ("OE") a certain 2005 three-month transaction that occurred in 2005 ("Transaction") between OERI and an unaffiliated third party. OERI reported, based on its initial findings, that the Transaction may have violated the FERC's shipper-must-have-title policy and the maximum rate cap applicable to natural gas transportation. OERI conducted an internal investigation ("Internal Investigation") into the Transaction and on December 18, 2007, at OE's request, OERI provided a written report to the OE of that Internal

Investigation. By letter dated December 20, 2007, OE advised OERI that it had commenced a preliminary, non-public investigation into compliance matters relating to the Transaction. On February 7, 2008, the OE submitted to OERI discovery requests relating to various aspects of the Transaction and Internal Investigation. OERI responded to the discovery requests on February 28, 2008. OERI will supplement the written report of its Internal Investigation, if necessary, to address any other similar transactions or practices that it may identify as raising potential compliance issues in the course of its Internal Investigation.

The FERC has imposed substantial civil penalties on entities subject to its jurisdiction that violate provisions of the Natural Gas Act. Some self-reports to OE have resulted in settlements requiring the entities to pay significant civil penalties, whereas others have been concluded without a penalty payment or any other remedial measures being required. At this time the Company cannot determine or predict either the timing of the completion or the final outcome of OE's investigation of the OERI self-report.

Potential Collateral Requirements

In the event Moody's or Standard & Poor's were to lower Enogex's senior unsecured debt rating to a below investment grade rating, at December 31, 2007, Enogex would have been required to post approximately $26.3 million of collateral to satisfy its obligation under its financial and physical contracts.

Environmental Laws and Regulations

Approximately $36.9 million and $121.4 million, respectively of the Company's capital expenditures budgeted for 2008 and 2009 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 $99.2 million during 2008 as compared to approximately $68.4 million in 2007. 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 15, 2005, the U.S. Environmental Protection Agency ("EPA") issued the Clean Air Mercury Rule ("CAMR") to limit mercury emissions from coal-fired boilers. On February 8, 2008, the U.S. Court of Appeals for the D.C. Circuit Court vacated the rule. One possible consequence is that the EPA will develop regulations that are more stringent than the CAMR and the trading of mercury allowances will not be allowed. Until the rule was vacated, the CAMR required mercury monitoring to begin in 2009. Accordingly, OG&E is in the process of installing mercury monitoring equipment on all five of its coal units. The cost of the monitoring equipment was approximately $5.0 million in 2007 and OG&E expects to spend approximately $0.7 million in 2008. Because the CAMR was vacated, the cost to install additional mercury controls is uncertain at this time but may be significant, particularly if the EPA develops more stringent requirements. The outcome of the CAMR ruling does not preclude states from developing more stringent mercury reduction requirements. In 2006, the State of Oklahoma proposed to incorporate the EPA's CAMR, along with the proposed mercury allowance allocations, into the state implementation program. In January 2008, in response to citizen requests, the Oklahoma Department of Environmental Quality ("ODEQ") proposed three options for regulation of mercury emissions. As initially proposed, one option recommended by the ODEQ Staff was that the CAMR be incorporated by reference into the state implementation plan. The other two options are intended to be more restrictive than the recently vacated federal CAMR. In general, the proposed options include provisions that mercury trading will not be allowed, higher levels of mercury control will be required and compliance timelines may be shortened in comparison with the CAMR Promulgation of an Oklahoma rule may be further delayed if the ODEQ decides to wait for the EPA to re-promulgate a federal mercury rule. OG&E will continue to participate in the state rule making process.

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 to address these visibility impacts.

In September 2005, the ODEQ informally notified affected utilities that they would be required to perform a study to determine their impact on visibility in Federal Class I areas. Affected utilities are those which have "Best Available Retrofit Technology ("BART") eligible sources" (sources built between 1962 and 1977). For OG&E, these include various generating units at various generating stations. Regulations, however, allow an owner or operator of a BART-eligible source to request and obtain a waiver from BART if modeling shows no significant impact on visibility in nearby Class I areas. Based on this modeling, the ODEQ made a preliminary determination to accept an application for a waiver for the Horseshoe Lake generating station. The Horseshoe Lake waiver is expected to be included in the ODEQ state implementation plan. The due date for the ODEQ submission of the state implementation plan was December 17, 2007; however, the ODEQ has not yet submitted a plan to the EPA for approval. It is not known whether approval for the state implementation plan will be granted by the EPA.

The modeling did not support waivers for the affected units at the Seminole, Muskogee and Sooner generating stations. OG&E submitted a BART compliance plan for Seminole on March 30, 2007 committing to installation of nitrogen oxide ("NOX") controls on all three units. At the same time, OG&E submitted a determination to the ODEQ that an alternative compliance plan for the affected units at the Muskogee and Sooner power plants will achieve overall greater visibility improvement than BART in the affected Class I areas and the alternative plan extends the timeline for compliance to 2018. The estimated cost for this alternative plan and the BART compliance plan for the Seminole power plant is approximately $470 million. The alternative compliance plan includes installing semi-dry scrubbers on three of four affected coal units and low NOX burner equipment on all four coal units. This alternative plan was subject to approval by the ODEQ and the EPA. The EPA provided an opinion to the ODEQ that OG&E's alternative compliance plan does not meet the requirements of the regional haze rules. On November 16, 2007, the ODEQ notified OG&E that additional analysis will be required before the OG&E BART plan can be accepted. As required by the ODEQ, OG&E has initiated the additional analysis with a projected completion date of March 1, 2008. Until a compliance plan has been approved by the EPA, which is expected by December 31, 2008, the annual cost of compliance remains unknown at this time. The cost to comply with the regional haze regulations could increase substantially based on the interpretation of the requirements by the ODEQ and the EPA, the availability of alternative control measures to achieve more cost effective visibility improvements, the availability of materials, labor force and the specific design criteria for OG&E's generating units. OG&E expects that any necessary environmental expenditures will qualify as part of a pre-approval plan to handle state and federally mandated environmental upgrades which will be recoverable in Oklahoma from OG&E's retail customers under House Bill 1910, which was enacted into law in May 2005.

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 2007 were approximately 0.32 lbs/MMBtu. The regulations require that OG&E achieve a NOX emission level of 0.40 lbs/MMBtu for these boilers beginning in 2008. It is expected that NOX emissions will be further reduced to 0.15 lbs/MMBtu by 2016 if the regional haze compliance plan discussed above is approved by the EPA. Further reductions in NOX emissions could be required if the ODEQ determines that such NOX emissions are impacting 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 likely require significant capital and operating expenditures.

Currently, the EPA has designated Oklahoma "in attainment" with the ambient standard for ozone. However, future elevated readings could lead to redefinition of these areas as non-attainment. Both Tulsa and Oklahoma City have entered into an "Early Action Compact" with the EPA whereby voluntary measures are required to be enacted to reduce the impact of ambient levels of ozone. This compact expired in December 2007. However, a similar program called Ozone Flex began in January 2008 in which both Oklahoma City and Tulsa are participating. Currently, the EPA is reevaluating the current ozone standard and proposed further reductions in the ambient standard on September 20, 2007. The Company cannot predict the final outcome of this evaluation or its timing or affect on the Company's operations.

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 that they have completed this demonstration and Oklahoma does not affect air quality in downwind states. The demonstration was properly submitted by the state to the EPA on May 7, 2007, and additional information was submitted by the state to EPA on December 5, 2007. Assuming the state implementation plan is approved as submitted, there should be no significant adverse impact to OG&E as a result of the April 25, 2005 finding. The date of EPA approval is currently unknown.

On September 21, 2006, the EPA lowered the 24-hour fine particulate ambient standard while retaining the annual standard at its current level and promulgated a new standard for inhalable coarse particulates. Based on past monitoring data, it appears that Oklahoma may be able to remain in attainment with these standards. 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 sulfur dioxide (“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 chimney. 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 2007, OG&E’s SO2 emissions were below the allowable limits.

The EPA allocated SO2 allowances to OG&E starting in 2000 and OG&E started banking allowances in 2001. OG&E sold no banked allowances in 2007. Also, during 2007, OG&E received proceeds of approximately $0.5 million from the annual EPA spot (year 2007) and seven-year advance (year 2014) allowance auctions that were held in March 2007.

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, 2007, 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 2007. In January 2008, the ODEQ proposed fee increases of approximately 28 percent for Title V sources. These fee increases were approved by the Oklahoma Air Quality Council on February 5, 2008. The final outcome of this measure is dependent upon approval by the ODEQ Board and the Oklahoma state legislature. If approved, the fee increases will be effective July 1, 2008.

In addition to the requirements related to emissions of SO2, NOX and mercury discussed above, there is a growing concern nationally and internationally about global climate change and the contribution of emissions of greenhouse gases including, most significantly, carbon dioxide. This concern has led to increased interest in legislation at the federal level, actions at the state level, as well as litigation relating to greenhouse gas emissions, including a recent U.S. Supreme Court decision holding that the EPA has the authority to regulate carbon dioxide emissions from motor vehicles under the Clean Air Act. Increased pressure for carbon dioxide emissions reduction also is coming from investor organizations and the international community.

On the legislative front, in June 2005, the U.S. Senate adopted a resolution declaring that mandatory reductions in greenhouse gases are needed. Despite executive branch opposition to any mandatory requirements, several bills that would cap or tax greenhouse gases from electric utilities are being considered by Congress, and the concept of such regulation has received support from the majority leadership in both the U.S. Senate and U.S. House of Representatives.

Oklahoma and Arkansas have not, at this time, established any mandatory programs to regulate carbon dioxide and other greenhouse gases. However, government officials in these states have declared support for state and federal action on climate change issues. OG&E reports quarterly its carbon dioxide emissions and is continuing to evaluate various options for reducing, avoiding, off-setting or sequestering its carbon dioxide emissions. If legislation or regulations are passed at the federal or state levels in the future requiring mandatory reductions of carbon dioxide and other greenhouse gases on generation facilities to address climate change, this could result in significant additional compliance costs that would affect our future consolidated financial position, results of operations and cash flows if such costs are not recovered through regulated rates.

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 2007, 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 received two Oklahoma Pollutant Discharge Elimination System ("OPDES") permits in February 2008. OG&E is currently reviewing these permits to determine if they are reasonable in their requirements, allow operational flexibility and provide reductions in operating costs. Additionally, OG&E filed an application with the State of Oklahoma during 2006 for a new wastewater discharge permit for one of its facilities. This new permit was issued in the fourth quarter of 2007.

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 Section 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. OG&E has also provided the State of Oklahoma with information and requests that, if approved by the state, may reduce the impact of the Section 316(b) rules on OG&E. On January 25, 2007, a federal court reversed and remanded certain portions of the Section 316(b) rules to the EPA. On July 9, 2007, the EPA suspended these portions of the Section 316(b) rules for existing facilities. As a result of such suspension, permits required for existing facilities are to be developed by the individual states using their best professional judgment until the EPA completes its review of the suspended sections. In September 2007, the State of Oklahoma indicated that it was requiring a comprehensive demonstration study be submitted by January 7, 2008 for each affected facility. On January 7, 2008, OG&E submitted the requested studies for its facilities. It is not clear what changes, if any, the EPA will ultimately make to the Section 316(b) rules or how those changes may affect OG&E. Depending on the ultimate analysis and final determinations regarding the Section 316(b) rules and the Oklahoma comprehensive demonstration studies, 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 are subject to stringent and complex federal, state and local laws and regulations, governing environmental protection as well as the discharge of materials into the environment. These laws and regulations can restrict or impact Enogex's business activities in many ways, such as restricting the way it can handle or dispose of its wastes, requiring remedial action to mitigate pollution conditions that may be caused by its operations or that are attributable to former operators, regulating future construction activities to avoid endangered species or enjoining some or all of the operations of facilities deemed in noncompliance with permits issued pursuant to such environmental laws and regulations. In most instances, the applicable regulatory requirements relate to water and air pollution control or solid waste management measures. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes impose strict, joint and several liability for costs required to clean up and restore sites where substances or wastes have been disposed or otherwise released into the environment. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of substances or wastes into the environment. Enogex handles 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 consolidated financial position or results of operations. The Company believes, however, that it is reasonably likely that the trend in environmental legislation and regulations will continue towards more restrictive standards. Compliance with these standards may incrementally increase the cost of conducting business.

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.

Air

Currently, the EPA has designated Oklahoma "in attainment" with the ambient standard for ozone. However, future elevated readings could lead to redefinition of these areas as non-attainment. Both Tulsa and Oklahoma City have entered into an "Early Action Compact" with the EPA whereby voluntary measures are required to be enacted to reduce the impact of ambient levels of ozone. This compact expired in December 2007. However, a similar program called Ozone Flex began in January 2008 in which both Oklahoma City and Tulsa are participating. Currently, the EPA is reevaluating the current ozone standard and proposed further reductions in the ambient standard on September 20, 2007. The Company cannot predict the final outcome of this evaluation or its timing or affect on the Company's operations.

The ODEQ Clean Air Act Amendment Title V permitting program was approved by the EPA in March 1996. As of December 31, 2007, Enogex had received all required Title V permits and intends to continue to renew these permits as necessary. Environmental permits and fees for Enogex facilities were approximately $0.2 million in 2007. The fees for 2008 are projected to be approximately 23 percent higher than the 2007 fees. In January 2008, the ODEQ proposed fee increases of approximately 28 percent for Title V sources and 13 percent for minor sources. These fee increases were approved by the Oklahoma Air Quality Advisory Council on February 5, 2008. The final outcome of this measure is dependent upon approval by the ODEQ Board and the Oklahoma state legislature. If approved, the fee increases will be effective July 1, 2008.

There is a growing concern nationally and internationally about global climate change and the contribution of emissions of greenhouse gases including, most significantly, carbon dioxide. This concern has led to increased interest in legislation at the federal level, actions at the state level, as well as litigation relating to greenhouse gas emissions, including a recent U.S. Supreme Court decision holding that the EPA has the authority to regulate carbon dioxide emissions from motor vehicles under the Clean Air Act. Increased pressure for carbon dioxide emissions reduction also is coming from investor organizations and the international community.

On the legislative front, in June 2005, the U.S. Senate adopted a resolution declaring that mandatory reductions in greenhouse gases are needed. Despite executive branch opposition to any mandatory requirements, several bills that would cap or tax greenhouse gases from electric utilities are being considered by Congress, and the concept of such regulation has received support from the majority leadership in both the U.S. Senate and U.S. House of Representatives.

Oklahoma and Texas have not, at this time, established any mandatory programs to regulate greenhouse gases. However, government officials in these states have declared support for state and federal action on climate change issues. Enogex is a partner in the EPA Natural Gas STAR Program, a voluntary program to reduce methane emissions. If legislation or regulations are passed at the federal or state levels in the future requiring mandatory reductions of greenhouse gases to address climate change, this could have a significant impact on Enogex's operations.

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. When appropriate, 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 otherwise stated above, in Note 17 below and in Item 3 of this Annual Report on Form 10-K, 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.

17. 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, 2007, 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 the FERC jurisdictional rates.

Completed Regulatory Matters

OCC Order Confirming Savings / Acquisition of McClain Power Plant

The 2002 Settlement Agreement required that, if OG&E did not acquire electric generation of not less than 400 MW ("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. On July 9, 2004, OG&E completed the acquisition of the McClain Plant which was intended to satisfy the requirement in the 2002 Settlement Agreement to acquire New Generation. On June 7, 2007, OG&E filed an application with the OCC supporting its compliance with the 2002 Settlement Agreement. On November 21, 2007, OG&E received an order from the OCC affirming that the acquisition of the McClain Plant provided savings to OG&E's Oklahoma customers in excess of the required $75 million over the three-year period from January 1, 2004 through December 31, 2006.

Security Enhancements

OG&E filed an application with the OCC on December 15, 2006 to amend its security plan to seek approval of approximately $7.6 million of cost increases related to the expanded scope of previously authorized projects and approximately $10.9 million for new security projects with an associated annual revenue requirement of approximately $2.7 million. On June 26, 2007, the OCC issued an order approving approximately $17.6 million of security capital expenditures and the associated revenue requirement of approximately $2.6 million, which OG&E implemented during the first billing cycle of July 2007.

Review of OG&E's Fuel Adjustment Clause for Calendar Year 2005

The OCC routinely audits activity in OG&E's fuel adjustment clause for each calendar year. In October 2006, the OCC Staff filed an application for a review of OG&E's 2005 fuel adjustment clause. In September 2007, the OCC issued an order approving the fuel, purchased power and purchase gas adjustment clause cost recoveries for calendar year 2005.

Cogeneration Credit Rider

OG&E's cogeneration credit rider was initially implemented in 2005 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 cogeneration credit rider was updated and approved by the OCC in December of each year through December 2006 and any over/under recovery of the cogeneration credit rider in the current year and prior periods was automatically included in the next year's rider. OG&E filed an application with the OCC in September 2007 to request a new cogeneration credit rider for years after 2007 as OG&E's current cogeneration credit rider expired on December 31, 2007. In December 2007, the OCC issued an order approving a cogeneration credit rider that expires on December 31, 2009.

OG&E Wind Power Filing

In January 2007, OG&E's 120 MW Centennial wind farm was fully in service. As a result, on January 17, 2007, OG&E sent notice of this to the OCC which triggered the recovery rider in the first billing cycle of February 2007. The recovery rider, which was previously approved in an OCC settlement, authorized recovery for up to $205 million in construction costs and allowance for funds used during construction and was designed to recover the lower of a capped or actual revenue requirement including a return on equity of 10.75 percent. OG&E spent approximately $203.8 million related to the Centennial wind farm. OG&E expects the recovery rider to remain in effect through late 2009. As indicated in the settlement agreement with the OCC related to OG&E's Centennial wind farm, OG&E must file for a general rate review that will permit the OCC to issue an order no later than December 31, 2009.

OG&E Arkansas Rate Case Filing

On July 28, 2006, OG&E filed with the APSC an application for an annual rate increase of approximately $13.5 million to recover, among other things, its investment in, and the operating expenses of, the McClain Plant, the Centennial wind power project and the costs of electric system expansion and upgrades based on a return on equity of 11.75 percent. On January 5, 2007, the APSC issued an order providing for a $5.4 million annual increase in OG&E's electric rates, a 10.0

percent return on equity and the recovery of the Arkansas portion of the Centennial wind farm expenditures. The Arkansas rates became effective in February 2007.

OG&E FERC Audit

On May 29, 2006, the FERC notified OG&E that it was commencing an audit to determine whether and how OG&E is complying with: (i) its Open Access Transmission Tariff; (ii) requirements of its market-based rate authorization; (iii) Standards of Conduct and Open Access Same-Time Information System; and (iv) wholesale fuel adjustment clause tariff and other requirements contained in FERC regulations. Over the past several years, the FERC has conducted numerous audits of utilities across the country to ensure regulatory compliance. On June 29, 2007, the FERC issued its final audit report with a limited set of findings and recommended certain actions that OG&E has since implemented. Among its findings, the FERC concluded that OG&E did not make the appropriate refunds to certain wholesale customers subsequent to the OCC issuing an order changing the amount of storage costs in OG&E's gas transportation and storage agreement with Enogex that are recoverable from Oklahoma retail customers. As a result, OG&E recomputed billings made after May 2003 to certain wholesale customers and issued refunds in accordance with FERC regulations. The total amount of the refunds was approximately $1.0 million, including interest, which OG&E had fully reserved on its books in December 2006.

Enogex FERC Audit

On May 29, 2007, the FERC notified Enogex that it was commencing an audit to determine whether and how Enogex is complying with periodic regulatory reporting requirements for intrastate pipelines. On the same day, the FERC notified a number of other intrastate pipelines and storage entities of comparable audits. In preparing for the audit, Enogex advised the FERC Staff that it had inadvertently failed to timely file three storage reports required under FERC regulations. Enogex promptly submitted those storage reports to the FERC. The FERC completed its audit of Enogex in September 2007 and approved the corrective actions taken by Enogex and determined that no further corrective action is required.

Southwest Power Pool

In February 2007, OG&E began participating in the SPP's energy imbalance service market in a dual role as a load serving entity and as a generation owner. The energy imbalance service market requires cash settlements for over or under schedules of generation and load. Market participants, including OG&E, are required to submit resource plans and can submit offer curves for each resource available for dispatch. A function of interchange accounting is to match participants' MWH entitlements (generation plus scheduled bilateral purchases) against their MWH obligations (load plus scheduled bilateral sales) during every hour of every day. If the net result during any given hour is an entitlement, the participant is credited with a spot-market sale to the SPP at the respective market price for that hour; if the net result is an obligation, the participant is charged with a spot-market purchase from the SPP at the respective market price for that hour. The SPP purchases and sales are not allocated to individual customers. OG&E records the hourly sales to the SPP at market rates in Operating Revenues and the hourly purchases from the SPP at market rates in Cost of Goods Sold in its Consolidated Financial Statements.

FERC Ruling under PURPA

On September 25, 2007, as amended on October 24, 2007, OG&E filed an application with the FERC seeking relief from its obligation to purchase electric energy and capacity from QFs with a net capacity greater than 20 MW as required by PURPA. The Energy Policy Act of 2005 established a process that allows utilities to terminate the mandatory purchase obligation in certain circumstances. In an order dated January 22, 2008, the FERC found that OG&E had met the aforementioned standard and granted OG&E's request. The order does not affect OG&E's existing QF contracts with AES and PowerSmith; however, it does grant OG&E an exemption from any purchase obligations otherwise arising under PURPA after the date of filing of OG&E's application.

Pending Regulatory Matters

Proposed Acquisition of Power Plant

On January 21, 2008, OG&E entered into a Purchase and Sale Agreement ("Purchase and Sale Agreement") with Redbud Energy I, LLC, Redbud Energy II, LLC and Redbud Energy III, LLC ("Redbud Sellers"), which are indirectly owned by Kelson Holdings LLC, a subsidiary of Harbinger Capital Partners Master Fund I, Ltd. and Harbinger Capital Partners Special Situations Fund, L.P. Pursuant to the Purchase and Sale Agreement, OG&E agreed to acquire from the Redbud Sellers the entire partnership interest in Redbud Energy LP which currently owns a 1,230 MW natural gas-fired, combined-cycle power generation facility in Luther, Oklahoma ("Redbud Facility"), for approximately $852 million, subject to working capital and inventory adjustments in accordance with the terms of the Purchase and Sale Agreement.

In connection with the Purchase and Sale Agreement, OG&E also entered into (i) an Asset Purchase Agreement ("Asset Purchase Agreement") with the OMPA and the Grand River Dam Authority ("GRDA"), pursuant to which OG&E agreed that it would, after the closing of the transaction contemplated by the Purchase and Sale Agreement, dissolve Redbud Energy LP and sell a 13 percent undivided interest in the Redbud Facility to the OMPA and sell a 36 percent undivided interest in the Redbud Facility to the GRDA, and (ii) an Ownership and Operating Agreement ("Ownership and Operating Agreement") with the OMPA and the GRDA, pursuant to which OG&E, the OMPA and the GRDA, following the completion of the transaction contemplated by the Asset Purchase Agreement, would jointly own the Redbud Facility and OG&E will act as the operations manager and perform the day-to-day operation and maintenance of the Redbud Facility. Under the Ownership and Operating Agreement, each of the parties would be entitled to its pro rata share, which is equal to its respective ownership interest, of all output of the Redbud Facility and would pay its pro rata share of all costs of operating and maintaining the Redbud Facility, including its pro rata share of the operations manager's general and administrative overhead allocated to the Redbud Facility.

The transactions described above are subject to the expiration or termination of the waiting period under the Hart-Scott-Rodino Antitrust Improvements Act, an order from the FERC authorizing the contemplated transactions, an order from the OCC approving the prudence of the transactions and an appropriate reasonable recovery mechanism, and other customary conditions. OG&E will not be obligated to complete the transactions if the orders from the FERC and the OCC contain any conditions or restrictions which are materially more burdensome than those proposed in OG&E's applications. Either OG&E or the Redbud Sellers may terminate the Purchase and Sale Agreement if the closing has not occurred on or prior to November 16, 2008; provided that the Redbud Sellers have the option to extend such deadline for up to an additional 180 days if the sole reason the closing has not occurred is because the governmental and regulatory approvals have not been obtained. There can be no assurances that the transactions will be completed or as to its ultimate timing. OG&E expects to file an application with the OCC in March 2008 asking the OCC to approve the prudency of the transactions and an appropriate reasonable recovery mechanism. The OCC rules provide that the OCC has up to 240 days to issue an order determining OG&E's pre-approval request. Absent a settlement, the earliest OG&E expects an order from the OCC is November 2008.

Cancelled Red Rock Power Plant

On October 11, 2007, the OCC issued an order denying OG&E and PSO's request for pre-approval of their proposed 950 MW Red Rock power plant project. The plant, which was to be built at OG&E's Sooner plant site, was to be 42 percent owned by OG&E, 50 percent owned by PSO and eight percent owned by the OMPA. As a result, on October 11, 2007, OG&E, PSO and the OMPA agreed to terminate agreements to build and operate the plant. At December 31, 2007, OG&E had incurred approximately $17.5 million of capitalized costs associated with the Red Rock power plant project. In December 2007, OG&E filed an application with the OCC requesting authorization to defer, and establish a method of recovery of, approximately $14.7 million of Oklahoma jurisdictional costs associated with the Red Rock power plant project that are currently reflected in Deferred Charges and Other Assets on the Company's Consolidated Balance Sheets. If the request for deferral is not approved, the deferred costs will be expensed. In February 2008, the OCC issued a procedural schedule with a hearing scheduled for May 7, 2008. OG&E expects to receive an order from the OCC in this matter by the end of 2008.

Review of OG&E's Fuel Adjustment Clause for Calendar Year 2006

The OCC routinely audits activity in OG&E's fuel adjustment clause for each calendar year. In September 2007, the OCC Staff filed an application for a prudence review of OG&E's 2006 fuel adjustment clause. OG&E is required to provide minimum filing requirements ("MFR") within 60 days of the application; however, OG&E requested and was granted an extension to file the MFRs by January 15, 2008, on which date the MFRs were submitted by OG&E. In February 2008, the OCC issued a procedural schedule with a hearing scheduled for August 21, 2008. OG&E expects to receive an order from the OCC in this matter by the end of 2008.

OG&E FERC Formula Rate Filing

On November 30, 2007, OG&E made a filing at the FERC to increase its transmission rates to wholesale customers moving electricity on OG&E's transmission lines. Interventions and protests were due by December 21, 2007. While several parties filed motions to intervene in the docket, only the OMPA filed a protest to the contents of OG&E's filing. OG&E filed an answer to the OMPA's protest on January 7, 2008. On January 31, 2008, the FERC issued an order (i) conditionally accepting the rates; (ii) suspending the effectiveness of such rates for five months, to be effective July 1, 2008, subject to refund; (iii) establishing hearing and settlement judge procedures; and (iv) directing OG&E to make a compliance filing. The first settlement conference was held on February 20, 2008. Another settlement conference is scheduled for May 9, 2008.

Enogex FERC Section 311 2007 Rate Case

On October 1, 2007, Enogex made its required triennial rate filing at the FERC to update its Section 311 maximum interruptible transportation rates for service in the East Zone and West Zone. Enogex's filing requested an increase in the maximum zonal rates and proposed to place such rates into effect on January 1, 2008. A number of parties intervened and some additionally filed protests. In the normal course of the triennial rate case, the FERC Staff and intervenors will serve data requests on Enogex with respect to the cost of service submitted with the filing in support of the proposed rates and the parties will, thereafter, undertake settlement discussions. There is no statutory deadline by which the FERC must act on the filing. The regulations provide that the FERC has 150 days to act on the filing but also permit the FERC to issue an order extending the time period for action, as the FERC has done in past Enogex cases. The FERC Staff has served its initial data requests on Enogex and Enogex has submitted its responses. The parties are currently in settlement negotiations. The FERC Staff, Enogex and one intervenor have exchanged offers of settlement, but a settlement has not been reached. Enogex has not, as of yet, placed the increased rates into effect. Enogex must file its next rate case no later than October 1, 2010 to comply with the FERC's requirement for triennial filings.

Enogex 2008 Fuel Filing

As required by the fuel tracker provisions of its Statement of Operating Conditions, Enogex files annually to update its fuel percentages. In the settlement of its 2004 Section 311 rate case, the Company agreed to move from a system-wide fuel percentage to zonal fuel percentages. Accordingly, in all of the annual fuel filings made subsequent to the FERC's acceptance of the 2004 rate case settlement, the Company has filed for fixed fuel percentages for the East Zone and the West Zone, respectively. On November 15, 2007, Enogex made its annual filing to establish the fixed fuel percentages for its East Zone and West Zone for calendar year 2008 ("2008 Fuel Year"). There were no protests and the FERC accepted the proposed zonal fuel percentages for 2008 Fuel Year by order of December 19, 2007.

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 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 new interim tests. OG&E and OERI submitted a compliance filing to the FERC on February 7, 2005 that applied the interim tests to OG&E and OERI. In the compliance filing, OG&E and OERI passed the pivotal supplier screen but did not pass the market share screen in OG&E's control area. OG&E and OERI provided an explanation as to why their failure of the market share screen in OG&E's control area should not be viewed as an indication that they can exercise generation market power.

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 established hearing procedures to investigate whether OG&E and OERI may continue to sell power at market-based rates in OG&E's control area. The order established a rebuttable presumption that OG&E and OERI have the ability to exercise market power in OG&E's control area. OG&E and OERI were 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 to loads that sink 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 sink in OG&E's control area. OG&E and OERI also informed the FERC that any new agreements for long-term sales (one year or longer in duration) to loads that sink in OG&E's control area will be filed with the FERC and that OG&E and OERI will not make such sales under their respective market-based rate tariffs. On January 20, 2006, the FERC issued a Notice of Institution of Proceeding and Refund Effective Date for the purpose of establishing the date from which any subsequent market-based sales would be subject to refund in the event the FERC concludes after investigation that the rates for such sales are not just and reasonable. The refund effective date was March 27, 2006.

On March 21, 2006, the FERC issued an order conditionally accepting OG&E's and OERI's proposal to mitigate the presumption of market power in OG&E's control area. First, the FERC accepted the additional information related to first-tier markets submitted by OG&E and OERI, and concluded that OG&E and OERI satisfy the FERC's generation market power standard for directly interconnected first-tier control areas. Second, the FERC directed the Company to make certain revisions to its mitigation proposal and file a cost-based rate tariff for short-term sales (one week or less) made within OG&E's control area. The FERC also expanded the scope of the proposed mitigation to all sales made within OG&E's control area (instead of only to sales sinking to load within OG&E's control area). On April 20, 2006, the Company submitted: (i) a compliance filing containing the specified revisions to the Company's market-based rate tariffs and the new cost-based rate tariff; and (ii) a request for rehearing asking the FERC to reconsider its expanded mitigation directive contained in the March 21, 2006 order. On May 22, 2006, the FERC issued a tolling order that effectively provided the FERC additional time to consider the April 20, 2006 rehearing request. On July 25, 2006 and August 25, 2006, pursuant to a FERC March 20, 2006 order, OG&E and OERI filed revisions to their market-based rate tariffs to allow them to sell energy imbalance service into the wholesale markets administered by the SPP at market-based rates. The FERC has not yet acted on OG&E's April 20, 2006, July 25, 2006 or August 25, 2006 filings. On February 6, 2007, OG&E and OERI submitted to the FERC a change in status report notifying the FERC that OG&E has placed into service OG&E's Centennial wind farm, a wind farm with a nameplate capacity rating of 120 MW. OG&E and OERI explained that adding this capacity was not material to the FERC's grant of market-based rate status to OG&E and OERI. On March 9, 2007, the FERC accepted OG&E's and OERI's change of status filing. On June 21, 2007, the FERC issued a final rule codifying and revising standards for market-based rate sales of electric energy, capacity and ancillary services. This final rule clarifies the scope of the mitigation applicable to sales within OG&E's control area. OG&E began complying with the final rule and must formally incorporate certain provisions into its market-based rate tariff the next time OG&E proposes a tariff change, makes a change in status filing or submits an updated market power analysis.

North American Electric Reliability Council

The Energy Policy Act of 2005 gave the FERC authority to establish mandatory electric reliability rules enforceable with monetary penalties. The FERC approved the North American Electric Reliability Council ("NERC") as the Electric Reliability Organization for North America and delegated to it the development and enforcement of electric transmission reliability rules. On April 19, 2007, the FERC approved the SPP as a Regional Entity whose primary function is to review and enforce compliance of reliability standards with all registered entities in the region. In March 2007, the FERC approved mandatory NERC reliability standards which became effective June 18, 2007. In June 2007, OG&E completed a NERC readiness evaluation. OG&E received the evaluation report from the NERC in December 2007 and has already implemented several of the recommendations. The Company is subject to a NERC readiness evaluation and compliance audit every three years. The next compliance audit is scheduled for 2008 and the next readiness evaluation is scheduled for 2010.

National Legislative Initiatives

In December 2007, the United States Congress passed and the President signed into law the Energy Independence and Security Act of 2007. Among other things, that legislation aims to create significant changes in the use of energy in the United States in the transportation and electric utility sectors. With regard to the impact on the utility sector in general and the Company in particular, the new energy law has a large number of provisions designed to increase the efficiency with which electricity is used in homes, as well as in commercial and industrial applications. New federal electric efficiency standards are to be developed and imposed on a wide range of appliances and equipment, buildings and manufacturing facilities. In addition, beyond direct action mandated to be taken by federal agencies to incentivize increased use of combined heat and power systems, cogeneration and demand response programs, the legislation also directs state public utility commissions to consider imposing similar proposals on utilities operating within the states' retail jurisdiction. Collectively, these provisions of the new law are intended to lower demand growth in the electricity sector through efficiency gains and reduce air emissions associated with the generation of electricity by utilities and the use of electricity by virtually every customer segment in the economy.

In December 2007, the United States Senate Environmental and Public Works Committee reported a bill to impose a federal "cap and trade" regime to control greenhouse gas emissions in this country. The legislation would impose significant regulatory and cost burdens on the utility sector, especially for those utilities like OG&E with coal-based generation. The Senate leadership intends to present the bill in 2008. In the United States House of Representatives, the Democratic leadership also aspires to have a global climate bill in 2008, with the intent to reach a final bill with the Senate that can be presented to the President before the end of 2008.

State Legislative Initiatives

In the 2007 legislative session, legislation was introduced in the Oklahoma legislature which proposed that electric utilities record fuel or natural gas removed from storage or stockpiles using the weighted-average cost method of accounting for inventory. Historically, the Company has used the LIFO method of accounting for inventory removed from storage or stockpiles. This legislation passed the legislature and was signed into law on June 5, 2007 and was effective January 1, 2008. OG&E filed an application with the OCC in September 2007 to address the accounting issues for the change in accounting for fuel inventory. In December 2007, the OCC issued an order approving the change in accounting for fuel inventory effective

January 1, 2008. This change in accounting for fuel inventory is not expected to have a material impact on the Company's consolidated financial position or results of operations.

Legislation was enacted in Oklahoma in the 1990's that was to restructure the electric utility industry in that state. The implementation of the Oklahoma restructuring legislation was delayed and seems unlikely to proceed anytime in the near future. Yet, if ultimately enacted, 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 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 Policy Act of 2005, 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.

18. 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:

	2007		2006	
December 31 *(In millions)*	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Price Risk Management Assets				
Energy Trading Contracts	**$ 8.0**	**$ 8.0**	$ 39.1	$ 39.1
Interest Rate Swaps	**---**	**---**	0.9	0.9
Price Risk Management Liabilities				
Energy Trading Contracts	**$ 30.2**	**$ 30.2**	$ 6.7	$ 6.7
Interest Rate Swaps	**1.7**	**1.7**	---	---
Long-Term Debt				
Senior Notes	**$ 807.4**	**$ 825.3**	$ 807.2	$ 820.7
Industrial Authority Bonds	**135.4**	**135.4**	135.4	135.4
Enogex Notes – continuing operations	**402.8**	**436.8**	406.7	433.5

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 generally 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. 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, 2007 and 2006, and the related consolidated statements of income, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedule listed in the Index at Item 15(a). 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, 2007 and 2006, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2007, 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 therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), OGE Energy Corp.'s internal control over financial reporting as of December 31, 2007, 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 26, 2008 expressed an unqualified opinion thereon.

As discussed in Notes 1, 4, 6, 9 and 14 to the consolidated financial statements, in 2006 the Company adopted Statement of Financial Accounting Standards No. 123 (Revised), "Share-Based Payment," and Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," and in 2007, the Company adopted Financial Accounting Standards Board Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," and Financial Accounting Standards Board Interpretation No. 39 (As Amended), "Offsetting of Amounts Related to Certain Contracts."

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 26, 2008

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)*		Mar 31	Jun 30	Sep 30	Dec 31	Total
Operating revenues	**2007**	**$ 881.5**	**$ 913.4**	**$ 1,044.5**	**$ 958.2**	**$ 3,797.6**
	2006	1,109.8	934.3	1,130.6	830.9	4,005.6
Operating income	**2007**	**$ 46.2**	**$ 117.2**	**$ 218.3**	**$ 73.6**	**$ 455.3**
	2006	51.8	117.7	220.6	42.6	432.7
Net income	**2007**	**$ 17.2**	**$ 62.6**	**$ 126.8**	**$ 37.6**	**$ 244.2**
	2006	24.9	93.7	121.4	22.1	262.1
Basic earnings per average common share	**2007**	**$ 0.19**	**$ 0.68**	**$ 1.38**	**$ 0.41**	**$ 2.66**
	2006	0.27	1.03	1.33	0.25	2.88
Diluted earnings per average common share	**2007**	**$ 0.19**	**$ 0.68**	**$ 1.37**	**$ 0.40**	**$ 2.64**
	2006	0.27	1.02	1.31	0.24	2.84

In January 2007, OG&E determined that the approved tariffs in its December 12, 2005 OCC rate case order had inadvertently authorized OG&E to collect, and OG&E had collected, approximately $26.7 million of additional fuel-related revenues during 2006 that was not intended by the order. As a result, OG&E filed with the OCC in January 2007 amendments to its previously-authorized tariffs in order to cease recovery of the fuel-related revenues not intended by the December 12, 2005 order. OG&E recorded a reduction in operating revenues of approximately $26.7 million and an increase in interest expense of approximately $0.5 million, which resulted in an after tax reduction in net income of approximately $16.7 million in the fourth quarter of 2006. On a quarterly basis, collections of such additional amounts under the previously-authorized tariffs represented approximately $7.8 million of operating revenues ($4.8 million of net income) for the quarter ended March 31, 2006, approximately $7.7 million of operating revenues ($4.7 million of net income) for the quarter ended June 30, 2006 and approximately $5.9 million of operating revenues ($3.6 million of net income) for the quarter ended September 30, 2006.

Dividends

COMMON STOCK

- Common quarterly dividends paid (as declared) in 2007 were $0.34 each for the first three quarters of 2007 and was $0.3475 for the fourth quarter of 2007. Common quarterly dividends paid (as declared) in 2006 were $0.33 ¼ each for the first three quarters of 2006 and was $0.34 for the fourth quarter of 2006. Common quarterly dividends paid (as declared) in 2005 were $0.33 ¼.
- Present rate – $0.34 ¾
- Payable 30th of January, April, July, and October

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 ("SEC") rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer ("CEO") and chief financial officer ("CFO"), allowing timely decisions regarding required disclosure. 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 CEO and CFO, of the effectiveness of the Company's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15(d)-15(e) under the Securities Exchange Act of 1934), 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, 2007. 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, 2007, 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 the Company's internal control over financial reporting. This report appears on the following page.

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
OGE Energy Corp.

We have audited OGE Energy Corp.'s internal control over financial reporting as of December 31, 2007, 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 included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on 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, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on our assessed risk, 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, OGE Energy Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, 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, 2007 and 2006, and the related consolidated statements of income, changes in stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2007 of OGE Energy Corp. and our report dated February 26, 2008 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 26, 2008

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

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 information regarding the Audit Committee financial expert.

Item 11. Executive Compensation.

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, 2007 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)	1,138,917	$21.34	1,759,162 (B)
Equity Compensation Plans Not Approved by Shareowners	---	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, and Director Independence.

Item 14. Principal Accounting Fees and Services.

Items 10, 11, 12, 13 and 14 (other than Item 10 information regarding the Code of Ethics and Item 12 information required by Item 201(d)(1) of Regulation S-K) are omitted pursuant to General Instruction G of Form 10-K, because the Company will file copies of a definitive proxy statement with the SEC on or about March 31, 2008. 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 Annual Report on 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 Annual Report:

- Consolidated Balance Sheets at December 31, 2007 and 2006
- Consolidated Statements of Capitalization at December 31, 2007 and 2006
- Consolidated Statements of Income for the years ended December 31, 2007, 2006 and 2005
- Consolidated Statements of Stockholders' Equity for the years ended December 31, 2007, 2006 and 2005
- Consolidated Statements of Cash Flows for the years ended December 31, 2007, 2006 and 2005
- 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	150

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)
1.02	Underwriting Agreement, dated January 28, 2008 between OG&E and Greenwich Capital Markets Inc. and BNY Capital Markets, Inc., on behalf of themselves and the other underwriters named therein relating to $200,000,000 in aggregate principal amount of OG&E's 6.45% Senior Notes, Series due February 1, 2038 (the "Senior Notes"). (Filed as Exhibit 1.01 to OG&E's Form 8-K filed January 31, 2008 (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)
2.14	Asset purchase agreement dated March 30, 2006, by and between Enogex Gas Gathering, L.L.C. and Hiland Operating, Inc. (Filed as Exhibit 2.01 to the Company's Form 8-K filed April, 4, 2006 (File No. 1-12579) and incorporated by reference herein)
2.15	Purchase and Sale Agreement, dated as of January 21, 2008, entered into by and among Redbud Energy I, LLC, Redbud Energy II, LLC and Redbud Energy III, LLC and OG&E (Certain exhibits and schedules hereto

have been omitted and the registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to the Company's Form 8-K filed January 25, 2008 (File No. 1-12579) and incorporated by reference herein)

2.16	Asset Purchase Agreement, dated as of January 21, 2008, entered into by and among OG&E, the Oklahoma Municipal Power Authority and the Grand River Dam Authority (Certain exhibits and schedules hereto have been omitted and the registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to the Company's Form 8-K filed January 25, 2008 (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 OGE Energy Corp. By-laws. (Filed as Exhibit 3.01 to OGE Energy's Form 8-K filed January 23, 2007 (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)
4.11	Supplemental Indenture No. 8 dated as of January 15, 2008 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed January 31, 2008 (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	The 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	The 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	The 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	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)
10.13	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)
10.14	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)
10.15	Amendment No. 1 to the 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)

10.16	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)
10.17	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)
10.18	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)
10.19	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)
10.20	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)
10.21	Form of Restricted Stock Agreement under 2003 Stock Incentive Plan. (Filed as Exhibit 10.31 to OGE Energy'sForm 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)
10.22	Form of Split Dollar Agreement. (Filed as Exhibit 10.32 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)
10.23	Credit agreement dated December 6, 2006, by and between the Company, the Lenders thereto, Wachovia Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, and The Royal Bank of Scotland plc, UBS Securities LLC and Union Bank of California, N.A., as Co-Documentation Agents. (Filed as Exhibit 99.01 to the Company's Form 8-K filed December 12, 2006 (File No. 1-12579) and incorporated by reference herein)
10.24	Credit agreement dated December 6, 2006, by and between OG&E, the Lenders thereto, Wachovia Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, and The Royal Bank of Scotland plc, Mizuho Corporate Bank and Union Bank of California, N.A., as Co-Documentation Agents. (Filed as Exhibit 99.02 to the Company's Form 8-K filed December 12, 2006 (File No. 1-12579) and incorporated by reference herein)
10.25	Amendment No. 6 to the OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.33 to OGE Energy's Form 10-K for the year ended December 31, 2005 (File No. 1-12579) and incorporated by reference herein)
10.26	Amendment No. 1 to the Company's 1998 Stock Incentive Plan. (Filed as Exhibit 10.26 to OGE Energy's Form 10-K for the year ended December 31, 2006 (File No. 1-12579) and incorporated by reference herein)
10.27	Amendment No. 2 to the Company's 2003 Stock Incentive Plan. (Filed as Exhibit 10.27 to OGE Energy's Form 10-K for the year ended December 31, 2006 (File No. 1-12579) and incorporated by reference herein)
10.28	Directors' Compensation.
10.29	Executive Officer Compensation.
10.30	Capacity Lease Agreement dated as of December 11, 2006, by and between Enogex, Inc. and Midcontinent Express Pipeline LLC. [Confidential treatment has been requested for certain portions of this exhibit.] (Filed as Exhibit 10.30 to OGE Energy's Form 10-K for the year ended December 31, 2006 (File No. 1-12579) and incorporated by reference herein)

10.31	OGE Energy Corp. Employees’ Stock Ownership and Retirement Savings Plan, as amended and restated. (Filed as Exhibit 10.31 to OGE Energy’s Form 10-K for the year ended December 31, 2006 (File No. 1-12579) and incorporated by reference herein)
10.32	Ownership and Operating Agreement, dated as of January 21, 2008, entered into by and among OG&E, the Oklahoma Municipal Power Authority and the Grand River Dam Authority (Filed as Exhibit 10.01 to the Company’s Form 8-K filed January 25, 2008 (File No. 1-12579) and incorporated by reference herein)
10.33	Amendment No. 1 to OGE Energy Corp. Employees’ Stock Ownership and Retirement Savings Plan, as amended and restated.
10.34	Amendment No. 2 to OGE Energy Corp. Employees’ Stock Ownership and Retirement Savings Plan, as amended and restated.
10.35	Letter of extension for the Company’s credit agreement dated November 11, 2007, by and between the Company and the Lenders thereto, related to the Company’s credit agreement dated December 6, 2006.
10.36	Letter of extension for OG&E’s credit agreement dated November 11, 2007, by and between OG&E and the Lenders thereto, related to OG&E’s credit agreement dated December 6, 2006.
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)
99.03	Copy of APSC order with Arkansas Public Service Commission Staff, the Arkansas Attorney General and others relating to OG&E’s rate case. (Filed as Exhibit 99.01 to OGE Energy’s Form 8-K filed January 11, 2007 (File No. 1-12579) and incorporated by reference herein)
	Executive Compensation Plans and Arrangements
10.01	Form of Change of Control Agreement for Officers of the Company and OG&E. (Filed as Exhibit 10.07 to OGE Energy’s Form 10-K for the year ended December 31, 1996 (File No. 1-12579) and incorporated by reference herein)
10.02	The 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	The 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	The 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)
10.15	Amendment No. 1 to the 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)
10.18	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)
10.19	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)
10.20	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)
10.21	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)
10.22	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)
10.25	Amendment No. 6 to the OGE Energy Corp. Restoration of Retirement Income Plan. (Filed as Exhibit 10.33 to OGE Energy's Form 10-K for the year ended December 31, 2005 (File No. 1-12579) and incorporated by reference herein)
10.26	Amendment No. 1 to the Company's 1998 Stock Incentive Plan. (Filed as Exhibit 10.26 to OGE Energy's Form 10-K for the year ended December 31, 2006 (File No. 1-12579) and incorporated by reference herein)
10.27	Amendment No. 2 to the Company's 2003 Stock Incentive Plan. (Filed as Exhibit 10.27 to OGE Energy's Form 10-K for the year ended December 31, 2006 (File No. 1-12579) and incorporated by reference herein)
10.28	Directors' Compensation.
10.29	Executive Officer Compensation.

10.31	OGE Energy Corp. Employees' Stock Ownership and Retirement Savings Plan, as amended and restated. (Filed as Exhibit 10.31 to OGE Energy's Form 10-K for the year ended December 31, 2006 (File No. 1-12579) and incorporated by reference herein)
10.33	Amendment No. 1 to OGE Energy Corp. Employees' Stock Ownership and Retirement Savings Plan, as amended and restated.
10.34	Amendment No. 2 to OGE Energy Corp. Employees' Stock Ownership and Retirement Savings Plan, as amended and restated.

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, 2005					
Reserve for Uncollectible Accounts	$ 4.5	$ 3.1	$ ---	$ 3.9 (A)	$ 3.7
Year Ended December 31, 2006					
Reserve for Uncollectible Accounts	$ 3.7	$ 7.0	$ ---	$ 6.3 (A)	$ 4.4
Year Ended December 31, 2007					
Reserve for Uncollectible Accounts	$ 4.4	$ 6.0	$ ---	$ 6.6 (A)	$ 3.8

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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 28th day of February, 2008.

OGE ENERGY CORP.
(Registrant)

By /s/ Peter B. Delaney
Peter B. Delaney
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 on behalf of the Registrant in the capacities and on the dates indicated.

Signature	Title	Date
/ s / Peter B. Delaney Peter B. Delaney	Principal Executive Officer and Director;	February 28, 2008
/ s / James R. Hatfield James R. Hatfield	Principal Financial Officer; and	February 28, 2008
/ s / Scott Forbes Scott Forbes	Principal Accounting Officer.	February 28, 2008
Herbert H. Champlin	Director;	
Luke R. Corbett	Director;	
John D. Groendyke	Director;	
Kirk Humphreys	Director;	
Robert Kelley	Director;	
Linda P. Lambert	Director;	
Robert O. Lorenz	Director;	
Leroy C. Richie	Director;	
Ronald H. White, M.D.	Director; and	
J. D. Williams	Director.	
/ s / Peter B. Delaney By Peter B. Delaney (attorney-in-fact)		February 28, 2008

OGE ENERGY CORP.
EXECUTIVE OFFICER COMPENSATION

Executive Compensation

In November 2007, the Compensation Committee (the “Committee”) of the OGE Energy Corp. board of directors took actions setting executives’ salaries, target amount of annual bonus awards and target amounts of long-term compensation awards for 2008. 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 2008 annual bonus targets and long-term awards are dependent on achievement of specified corporate goals that will be established by the Committee at a subsequent meeting, and no officer is assured of any payout.

Salary

The Committee established the base salaries for its senior executive group. The salaries for 2008 for the current OGE Energy officers who are expected to be named in the Summary Compensation Table in OGE Energy’s 2008 Proxy Statement (the “Named Executive Officers”) are as follows:

Named Executive Officer	2008 Base Salary
Peter B. Delaney, Chairman and Chief Executive Officer	$775,000
James R. Hatfield, Senior Vice President and Chief Financial Officer	$388,000
Danny P. Harris, Senior Vice President and Chief Operating Officer	$510,000
Scott Forbes, Controller and Chief Accounting Officer	$229,500
Paul L. Renfrow, Vice President, Public Affairs	$228,000

Establishment of 2008 Annual Incentive Awards

As stated above, at its November 2007 meeting, the Committee approved the target amount of annual incentive awards, expressed as a percentage of salary, with the officer having the ability, depending upon achievement of the 2008 corporate goals to be set by the Committee at a subsequent meeting, to receive from 0 percent to 150 percent of such targeted amount. For 2008, the targeted amount was 85 percent of salary for Mr. Delaney and ranged from 30 percent to 70 percent of salary for the other Named Executive Officers.

Establishment of Long-Term Awards

At its November 2007 meeting, the Committee also approved the level of target long-term incentive awards, expressed as a percentage of salary, with the officer having the ability to receive from 0 percent to 200 percent of such targeted amount at the end of a three-year performance period depending upon achievement of the corporate goals to be set by the Committee at a subsequent meeting. For 2008, the targeted amount was 205 percent of salary for Mr. Delaney and ranged from 35 percent to 120 percent for the other Named Executive Officers.

Other Benefits

Retirement Benefits. Virtually all of our employees, including executive officers, are eligible to participate in our pension plan and supplemental restoration plan that enables participants, including executive officers, to receive the same benefits that they would have received under our pension plan in the absence of limitations imposed by the federal tax laws. In addition, a Supplemental Executive Retirement Plan (the “SERP”), which was adopted in 1993, offers supplemental pension benefits to specified lateral hires. Mr. Delaney is the only executive officer who participates in the SERP. Mr. Delaney’s participation in the SERP was the result of arms-length bargaining between Mr. Delaney and the Company at the time of his hire in April 2002 as Executive Vice President of the Company.

Almost all employees of the Company, including executive officers, also are eligible to participate in our tax-qualified defined contribution savings plan (the "Retirement Savings Plan"). Under the Retirement Savings Plan, participants may contribute between two percent and 19 percent of their compensation. Participants may designate, at their discretion, all or any portion of their contributions as: (i) a before-tax contribution under Section 401(k) of the Internal Revenue Code subject to the limitations thereof; or (ii) a contribution made on an after-tax basis. In addition, participants age 50 or older may make as a before-tax contribution certain "catch-up" contributions as permitted under the Internal Revenue Code. The Company will match (other than the "catch-up contributions"), depending upon the participant's years of service and date of employment, 50 percent, 75 percent or 100 percent of the first six percent of compensation contributed. Participants' contributions are fully vested and non-forfeitable. The Company match contributions vest over a three-year period. After two years of service, participants become 20 percent vested in their Company contribution account and become fully vested on completing three years of service. In addition, participants fully vest when they are eligible for normal or early retirement under the Company's pension plan, in the event of their termination due to death or permanent disability or upon attainment of age 65 while employed by the Company or its affiliates.

The Company has a nonqualified deferred compensation plan that allows key employees, including executive officers, to defer compensation above government limitations on 401(k) contributions that apply to the Company's qualified Retirement Savings Plan and to defer taxation on all earnings on compensation deferred into the plan. Under the terms of the nonqualified deferred compensation plan, participants have the opportunity to elect to defer each year up to 70% of their base salary and up to 100% of their bonus.

The Company matches deferrals to make up for any match lost in the Retirement Savings Plan because of deferrals to the deferred compensation plan, and to allow for a match on that portion of the first 6% of total compensation deferred that exceeds the limits allowed in the Retirement Savings Plan. Matching credits vest based on years of service, with full vesting after six years or, if earlier, on retirement, disability, death, a change in control of the Company or termination of the plan.

Deferrals, plus any Company match, are credited to a special recordkeeping account in the participant's name. Earnings on the deferrals are indexed to the assumed investment funds selected by the participant. For 2007, those investment fund options included an OGE Energy Common Stock fund and various money market, bond and equity funds.

Normally, payments under the deferred compensation plan begin within one year after retirement. For these purposes, normal retirement age is 65 and the minimum age to qualify for early retirement is age 55 with at least five years of service. Benefits will be paid, at the election of the participant, either in a lump sum or a stream of annual payments for up to 15 years, or a combination thereof. Participants whose employment terminates before they qualify for retirement benefits will receive their vested account balance in one lump sum following termination as provided in the plan. Participants also will be entitled to pre- and post-retirement survivor benefits. If the participant dies while in employment before retirement, his or her beneficiary will receive a payment of the account balance plus a supplemental survivor benefit equal to two times the total amount of base salary and bonuses deferred under the plan. If the participant dies following retirement, his or her beneficiary will continue to receive the remaining vested account balance. Additionally, eligible surviving spouses will be entitled to a lifetime survivor annuity payable annually. The amount of the annuity is based on 50% of the participant's account balance at retirement, the spouse's age and actuarial assumptions established by the Company's benefits committee.

At any time prior to retirement, a participant may withdraw all or part of amounts attributable to his or her vested account balance at December 31, 2004, subject to a penalty of 10% of the amount withdrawn. In addition, at the time of the initial deferral election, a participant may elect to receive one or more in-service distributions on specified dates without penalty. Hardship withdrawals, without penalty, of amounts attributable to a participant's vested account balance as of December 31, 2004 may also be permitted at the discretion of the Company's benefits committee.

Perquisites. The Company also offers executive officers a limited amount of perquisites. These include payment of dues at luncheon and country clubs and the costs of an annual physical exam. The Company has historically provided up to $7,500 annually for tax and financial planning services. This perquisite was discontinued by the Committee during 2007.

Change-of-Control Provisions. Each of the executive officers has an employment agreement that provides for specified benefits upon termination following a change of control. If an executive officer's employment is terminated by the Company without "cause" or by the executive for "good reason" (as defined) following a change of control, the executive officer is entitled to, among other things, 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. "Good reason" is defined to include the ability of the executive to terminate voluntarily for any reason during the 30-day period immediately following the one-year anniversary of the change of control. Under the Company's agreements if an excise tax on excess parachute payments under Section 4999 of the Code would be imposed, the change-of-control payments will be reduced to a point where no excise tax would be payable, if such reduction would result in a greater after-tax payment. 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 Annual Report on Form 10-K.

In addition, pursuant to the terms of the Company's incentive compensation plans, upon a change of control, all stock options will vest immediately and, for a 60-day period following the change of control, executive officers may surrender their options and receive in return a cash payment equal to the excess of the change of control price (as defined) over the exercise price; all performance units will vest and be paid out immediately in cash as if the applicable performance goals had been satisfied at target levels; and any annual incentive award outstanding for the year in which the participant's termination occurs for any reason, other than cause, within 24 months after the change of control will be paid in cash at target level on a prorated basis.

Exhibit 10.33

Amendment Number 1
OGE Energy Corp. Employees' Stock Ownership
And Retirement Savings Plan
(As Amended and Restated Effective as of January 1, 2006)

OGE Energy Corp. (the "Company"), an Oklahoma corporation, by action of its Board of Directors taken in accordance with the authority reserved to it by Section 13.1 of the OGE Energy Corp. Employees' Stock Ownership and Retirement Savings Plan (As Amended and Restated Effective as of January 1, 2006) (the "Plan"), hereby amends the Plan, effective as of July 18, 2007, as follows:

1. By adding the phrase "the Investment Committee," after the phrase "the Benefits Committee," where it appears in Section 2.22 of the Plan.

2. By adding a new Section 2.25A after Section 2.25 as follows:

"Section 2.25A Investment Committee. The term "Investment Committee" means the committee appointed by the Board of Directors pursuant to Section 13.3(c)."

3. By deleting the first two sentences of Section 8.1 of the Plan and inserting in lieu thereof the following:

"The Investment Committee shall cause the Trustee to establish and maintain the Investment Funds offered under the Plan, except for the OGE Energy Corp. Common Stock Fund. It is OGE Energy Corp.'s intent in its settlor capacity that the OGE Energy Corp. Common Stock Fund provided for in Section 8.1(a) shall be established and maintained as a permanent feature of the Plan as provided in said Section 8.1(a). Consistent with the foregoing, the Investment Committee shall have the authority to add or delete funds as it deems appropriate without amending this Plan document."

4. By deleting the phrase "or exercise" where it appears in the second sentence of Section 8.7 of the Plan.

5. By deleting Section 13.1 of the Plan and inserting in lieu thereof the following:

"Section 13.1 Allocation of Responsibilities Among Fiduciaries. The Fiduciaries shall have only those specific powers, duties, responsibilities and obligations as are specifically allocated to them under the Plan and Trust. In general, the Board of Directors shall have the sole responsibility to appoint and remove the Trustee or Trustees, members of the Investment Committee and members of the Benefits Oversight Committee; the authority to amend the Plan, in whole or in part, including when such amendment or group of related amendments would result in an estimated annual cost to the Plan of 25% or more of the annual cost of Company contributions (excluding Employee Contributions) under the Plan; and the authority to terminate, in whole or in part, the Plan and Trust. The Benefits Oversight Committee shall have the responsibilities described in Section 13.3(a). The Benefits Committee shall have the responsibilities described in Section 13.3(b). The Investment Committee shall have the responsibilities described in Section 13.3(c). The Plan Administrator shall have the duties described in Section 13.2. The Trustee shall have the sole responsibility for the administration of the Trust and the management of the assets under the Trust, all as specifically provided in the Trust and subject to the investment policy adopted by the Investment Committee. The Trustee will be responsible only for the assets of the Trust which it manages. If an investment manager is appointed, the investment manager will have sole responsibility for the management of the assets of the Trust specifically allocated to it. Each Fiduciary warrants that any directions given, information furnished or action taken by it shall be in accordance with the provisions of the Plan and Trust, as the case may be, authorizing or providing for such direction, information or action. Furthermore, each Fiduciary may rely upon any such direction, information or action of another Fiduciary as being proper under the Plan and Trust, and is not required under the Plan or Trust to inquire into the propriety of any such direction, information or action except that each Fiduciary shall not be relieved from liability for a breach of fiduciary responsibility by a co-Fiduciary under Section 405(a) of Title I of ERISA. It is intended under the Plan and Trust that each Fiduciary shall be responsible for the proper exercise of its own powers, duties, responsibilities and obligations under the Plan. The Benefits Oversight Committee, the Investment Committee, the Benefits Committee and the Plan Administrator may delegate their powers, duties, responsibilities and obligations to any other individual or entity, provided that to be effective, such delegation shall be agreed to in a written document signed by the parties involved."

6. By deleting the introductory portion of the first paragraph of Section 13.3(a)(ii) of the Plan and inserting in lieu thereof the following:

"The Benefits Oversight Committee shall be responsible for appointing and removing the members of the Benefits Committee. In addition, the Benefits Oversight Committee shall have the power to amend the Plan without the approval of the Board of Directors for the following reasons:"

7. By deleting Sections 13.3(c)-(j) of the Plan and inserting in lieu thereof the following:

"(c) Investment Committee.

(i) Appointment. The Investment Committee shall consist of at least two (2) members appointed by the Board of Directors, who may also be officers, directors, employees, agents or shareholders of OGE Energy Corp. Investment Committee members may resign by written notice to, or may be removed by, the Board of Directors, which shall appoint a successor to fill any vacancy on the Investment Committee so as to maintain at least two (2) members. The Secretary of OGE Energy Corp. shall advise the Trustee in writing of the names of the members of the Investment Committee and of any changes that may occur in its membership from time to time.

(ii) Specific Powers and Duties. In addition to discharging all other duties delegated to it as set forth in the Plan, the Investment Committee shall be responsible for appointing and removing any investment manager and reviewing the performance of the Trustee appointed by the Board of Directors and recommending to the Board of Directors the appointment, retention or termination of any such Trustee. In addition, the Investment Committee shall establish an investment policy, which shall be communicated to the Trustee and any investment manager.

The Investment Committee shall have such powers as may be necessary to discharge its duties hereunder and shall provide the Board of Directors with a report of its actions on an annual basis.

(d) Limitation on Powers. The Investment Committee and Benefits Committee shall have no power to add to, subtract from or modify any of the terms of the Plan, to change or add to any benefits provided by the Plan, or to waive or fail to apply any requirements for eligibility under the Plan.

(e) Conflicts of Interest. No member of the Benefits Committee, the Investment Committee or the Benefits Oversight Committee shall participate in any action on matters involving solely his or her own rights or benefits as a Participant under the Plan. Any such matters shall instead be determined by the other members of the Benefits Committee, the Investment Committee or the Benefits Oversight Committee, as applicable. If, in any case in which any Benefits Oversight Committee member, Investment Committee member or Benefits Committee member is so disqualified to act, the remaining members cannot agree or if there is only one individual member of such committee, the Board of Directors will appoint a temporary substitute member to exercise all of the powers of the disqualified member concerning the matter in which the disqualified member is not qualified to act. The Benefits Oversight Committee, the Investment Committee, the Benefits Committee and any individual member of such committees shall be fully protected when acting in a prudent manner and relying in good faith upon the advice of the following professional consultants or advisors employed by the Company, the Benefits Oversight Committee, the Investment Committee or the Benefits Committee: any attorney insofar as legal matters are concerned, any certified public accountant insofar as accounting matters are concerned and any enrolled actuary insofar as actuarial matters are concerned.

(f) Trustee's Directions. The Benefits Committee shall direct the Trustee concerning disbursements which shall be made out of the Trust pursuant to the provisions of the Plan and Trust. Any direction by the Benefits Committee to the Trustee shall be in writing and may be signed by any member of the Benefits Committee or any party authorized by the Benefits Committee.

(g) Committee Procedures. The Benefits Oversight Committee, the Investment Committee and the Benefits Committee may act at a meeting or by writing without a meeting, by the vote or assent of a majority of its respective members. The Benefits Oversight Committee, the Investment Committee and the Benefits Committee may adopt such bylaws and rules as they deem desirable for the conduct of their affairs and the administration of the Plan.

(h) Committee Records. The Benefits Oversight Committee, the Investment Committee and the Benefits Committee shall keep a record of all of their meetings and shall keep all such books of account, records and other data as may be necessary or desirable in their judgment for the administration of the Plan. The Benefits Oversight Committee, the Investment Committee and the Benefits Committee shall keep on file, in such form as each deems convenient and proper, all reports of the Trust received from the Trustee.

(i) Compensation; Reimbursement. Members of the Benefits Oversight Committee, the Investment Committee and the Benefits Committee shall not receive compensation for their services as such members, but OGE Energy Corp. shall reimburse them for any necessary expenses incurred in the discharge of their duties.

(j) Certain Indemnification. The current or former Plan Administrator and current and former members of the Board of Directors, the Benefits Oversight Committee, the Investment Committee and the Benefits Committee shall be indemnified by OGE Energy Corp. for all liability, joint or several, for their acts and omissions and for the acts and omissions of their agents and other Fiduciaries in the administration and operation of the Plan. The current and former Plan Administrator and current and former members of the Board of Directors, the Benefits Oversight Committee, the Investment Committee and the Benefits Committee shall also be indemnified by OGE Energy Corp. against all costs and expenses reasonably incurred by them in connection with the defense of any action, suit or proceeding in which they may be made party defendants by reason of their being or having been Plan Administrator, members of the Board of Directors, the Benefits Oversight Committee, the Investment Committee or the Benefits Committee, whether or not then serving as such, including the cost of reasonable settlements (other than amounts paid to OGE Energy Corp.) made to avoid costs of litigation and payment of any judgment or decree entered in such action, suit or proceeding. OGE Energy Corp. shall not, however, indemnify the Plan Administrator or any member of the Board of Directors, the Benefits Oversight Committee, the Investment Committee or the Benefits Committee with respect to any act finally adjudicated to have been caused by the willful misconduct of such individuals; or with respect to the cost of any settlement unless the settlement has been approved by a court of competent jurisdiction. The right of indemnification shall not be exclusive of any other right to which the Plan Administrator or member of the Board of Directors, the Benefits Oversight Committee, the Investment Committee or the Benefits Committee may be legally entitled and it shall inure to the benefit of the duly appointed legal representatives of such individual.

(k) Dissenting Members. A dissenting member of the Benefits Oversight Committee, the Investment Committee or the Benefits Committee who, within a reasonable time after he or she has knowledge of any action or failure to act by the Benefits Oversight Committee, the Investment Committee or the Benefits Committee, respectively, registers his or her dissent in writing delivered to the Benefits Oversight Committee, the Investment Committee or the Benefits Committee, as applicable, shall not be responsible for any such action or failure to act."

8. By adding the phrase ", Investment Committee" after the phrase "Benefits Oversight Committee" where it appears in Section 14.7 of the Plan.

9. By adding the phrase " the Investment Committee" after the phrase" the Benefits Committee," where it appears in Section 15.1 of the Plan.

10. By adding the phrase ", the Investment Committee" after the phrase "Benefits Committee," where it appears in Section 19.5 of the Plan.

IN WITNESS WHEREOF, the Company's Board of Directors has caused this instrument to be signed by a duly authorized officer of the Company on this 18th day of July 2007.

OGE ENERGY CORP.

By: /s/ Carla D. Brockman

Exhibit 10.34

Amendment Number 2 to the
OGE Energy Corp. Employees' Stock Ownership and Retirement Savings Plan
(As Amended and Restated Effective as of January 1, 2006)

OGE Energy Corp. (the "Company"), an Oklahoma corporation, by action of its Benefits Oversight Committee taken in accordance with the authority granted to it by Section 13.3 of the OGE Energy Corp. Employees' Stock Ownership and Retirement Savings Plan (As Amended and Restated Effective as of January 1, 2006), as heretofore amended (the "Plan"), hereby amends the Plan in the following respects effective as of January 18, 2008:

1. By adding a new Section 2.5A after Section 2.5 of the Plan as follows:

"Section 2.5A Automatic Compensation Reduction Agreement. The term "Automatic Compensation Reduction Agreement" means an arrangement under the Plan which an Eligible Employee is deemed to have entered into and pursuant to which the Eligible Employee is deemed to have elected to participate in the Plan and agreed to reduce his or her Compensation and the Eligible Employee's Participating Employer agrees to contribute to the Trust the amount so reduced as a Tax-Deferred Contribution."

2. By deleting the first sentence of Section 2.23 of the Plan and inserting in lieu thereof the following:

"The term "Forfeiture" means the portion of a Participant's Company Matching Contribution Account which by reason of the provisions of Section 4.1(c), 5.1(b), 6.4 or 10.3 can no longer become distributable to him or her."

3. By deleting Section 2.28 of the Plan and inserting in lieu thereof the following:

"Section 2.28 Participant. The term "Participant" means any Eligible Employee who has elected or is deemed to have elected to participate in the Plan pursuant to Section 3.2."

4. By deleting Section 2.41 of the Plan and inserting in lieu thereof the following:

"Section 2.41 Tax-Deferred Contributions. The term "Tax-Deferred Contributions" means the Employee Contributions under Section 5.1 which are designated as such by the Participant or are made pursuant to an Automatic Compensation Reduction Agreement. Tax-Deferred Contributions are intended to qualify as "salary reduction" contributions under Section 401(k) of the Code."

5. By adding two new sentences at the end of Section 3.2 as follows:

"Notwithstanding the foregoing, effective January 18, 2008, any Eligible Employee whose Employment Commencement Date occurs on or after December 17, 2007, and who has satisfied the requirements of Section 3.1 but has not affirmatively elected to become a Participant pursuant to the foregoing, shall be deemed to have elected to participate in the Plan pursuant to an Automatic Compensation Reduction Agreement and shall become a Participant as of the 30th day following the date the Eligible Employee has satisfied the requirements of Section 3.1 provided that by such date he or she has not affirmatively elected to become a Participant as provided in this Section 3.2 or affirmatively elected not to become a Participant. If any such Eligible Employee ceases to be an Eligible Employee by reason of termination of employment or otherwise, the preceding sentence shall not apply to such Eligible Employee on any subsequent re-employment with the Company or on otherwise again becoming an Eligible Employee."

6. By deleting Section 5.1 of the Plan and inserting in lieu thereof the following:

"Section 5.1 Employee Regular and Supplemental Contributions. (a) For each Payroll Period, each Participant shall contribute to the Plan an amount not less than two percent (2%) nor more than nineteen percent (19%) of his or her Compensation, which contributions shall be designated by the Participant, in whole multiples of one percent (1%) of Compensation, on the following basis:

(1) Contributions not exceeding the first six percent (6%) of Compensation shall be designated Regular Contributions. Regular Contributions may be designated as After-Tax Contributions or Tax-Deferred Contributions in any combination, provided that any such designation is made in whole multiples of one percent (1%) of Compensation.

(2) Contributions exceeding the first six percent (6%) of Compensation shall be designated Supplemental Contributions. Supplemental Contributions may be designated as After-Tax Contributions or Tax-Deferred Contributions, in any combination, provided that any such designation is made in whole multiples of one percent (1%) of Compensation.

(b) (i) Effective January 18, 2008 and subject to the provisions of Sections 5.5, 5.6 and 6.2, an Eligible Employee who becomes a Participant pursuant to an Automatic Compensation Reduction Agreement as provided in Section 3.2 shall be deemed to have elected to contribute to the Plan Tax-Deferred Contributions designated as Regular Contributions in an amount equal to 3% of Compensation per Payroll Period, by reduction of Compensation otherwise payable to the Participant, commencing as of the first day of the Payroll Period that begins as soon as administratively practicable after the date the Eligible Employee becomes a Participant as provided in Section 3.2; provided, however, that any such Participant may, not later than 90 days after the first Tax-Deferred Contribution made pursuant to the Automatic Compensation Reduction Agreement would otherwise have been paid to the Participant and notwithstanding any other provision of the Plan, elect to make a "permissible withdrawal" (as defined below in this Section 5.1) from the Plan of his or her Tax-Deferred Contributions (and any earnings (or losses) attributable thereto) that were made to the Trust pursuant to his or her Automatic Compensation Reduction Agreement through the last day of the Payroll Period beginning after the date the withdrawal election is made. Any Company Matching Contributions (as adjusted for earnings (or losses) attributable thereto) that are attributable to amounts distributed to a Participant by reason of a "permissible withdrawal" shall be forfeited and be considered a Forfeiture as of the date the distribution is made. In addition, the Participant's Automatic Compensation Reduction Agreement will terminate upon electing to make a "permissible withdrawal, and no further Tax-Deferred Contributions will be made on the Participant's behalf unless and until the Participant affirmatively makes an election to resume making Tax-Deferred Contributions under Section 5.2.

(ii) At least 30 days (and not more than 90 days) before the beginning of each Plan Year beginning after January 18, 2008 (or at such other time or times as required or permitted under applicable governmental regulations or guidance), the Benefits Committee (or its delegate) shall provide each Eligible Employee for the Plan Year who has satisfied the requirements of Section 3.1 and to whom the deemed participation provision of the Plan applies, notice of the Eligible Employee's rights and obligations under deemed participation pursuant to an Automatic Compensation Reduction Agreement, except that in the case of an Eligible Employee who does not receive the notice because the Employee becomes an Eligible Employee who has satisfied the requirements of Section 3.1 after the 90^{th} day before the beginning of the Plan Year or in the case of an Eligible Employee employed during the 2008 Plan Year, the notice shall be provided nor more than 90 days before, and no later than, 30 days prior to the date the Eligible Employee would be deemed to become a Participant as provided in Section 3.2 (or at such other time or times as is required or permitted under applicable governmental regulations or guidance). The notification shall include provisions required under applicable governmental regulations, including the following: (a) the level of Tax-Deferred Contributions which will be made on the Eligible Employee's behalf if the Eligible Employee does not make an affirmative election to participate, (b) his or her right to reject such deemed participation and elect to contribute as provided above in Section 5.1(a) or to elect not to have Tax-

Deferred Contributions made on his or her behalf, (c) the Investment Fund in which his or her Tax-Deferred Contributions shall be invested in the absence of any investment election and (d) his or her right to elect to make a “permissible withdrawal” from the Plan and the procedures to elect such a withdrawal. For purposes of this Section 5.1, the term “permissible withdrawal” shall have the meaning set forth in Section 414(w)(2) of the Code.

(iii) Notwithstanding any provision of this Section 5.1(b) or Section 3.2 to the contrary, an Automatic Compensation Reduction Agreement shall not become effective for any Eligible Employee who files in accordance with the procedures established by the Benefits Committee not later than the date he or she would otherwise be deemed to have elected to participate in the Plan under Section 3.2, an election to participate under Section 3.2 or an election not to have Tax-Deferred Contributions contributed to the Plan on his or her behalf.

(c) All Employee Contributions shall be effected by payroll deductions in accordance with procedures established by the Benefits Committee.

7. By adding a new sentence after the first sentence of Section 5.2 of the Plan as follows:

“Effective January 18, 2008, a Participant may elect in accordance with procedures established by the Benefits Committee to have his or her rate of Tax-Deferred Contributions to be made in the future automatically increased annually on a date and in an amount as specified by the Participant in such election, which amount shall be 1%, 2% or 3% of Compensation per Payroll Period. Such election shall remain in effect until canceled by the Participant in accordance with procedures designated by the Benefits Committee.”

8. By deleting Section 5.6(c)(i) of the Plan and inserting in lieu thereof the following:

“(i) Any distribution to Participants under this paragraph shall occur before the end of the Plan Year following the Plan Year in which the contributions were made. However, unless the distribution is made within the first 2½ months of that following Plan Year (or within the first 6 months in respect of the 2008 or subsequent Plan Years), the Participating Employer shall incur a 10% excise tax with respect to the excess not distributed to the extent required by law.”

9. By adding a new Section 5.6(f)(iv) after Section 5.6(f)(iii) of the Plan as follows:

“(iv) If a Participant withdraws in a “permissible withdrawal” under Section 5.1(b) Tax-Deferred Contributions made during the Plan Year pursuant to an Automatic Compensation Reduction Agreement, such Tax-Deferred Contributions so withdrawn shall not be taken into account for purposes of applying the tests under (a) above.”

10. By deleting Section 6.4(c)(i) of the Plan and inserting in lieu thereof the following:

“(i) Any distribution to Participants under this paragraph shall occur before the end of the Plan Year following the Plan Year in which the contributions were made. However, unless the distribution is made within the first 2½ months of that following Plan Year (or within the first 6 months in respect of the 2008 or subsequent Plan Years), the Participating Employer shall incur a 10% excise tax with respect to the excess not distributed to the extent required by law.”

11. By adding a new Section 6.4(e)(iii) after Section 6.4(e)(ii) of the Plan as follows:

“(iii) If a Participant forfeits Company Matching Contributions made during a Plan Year pursuant to Section 5.1(b) because if he or she makes a “permissible withdrawal” under Section 5.1(b), such Company Matching Contributions shall not be taken into account for purposes of applying the tests under (a) above.”

12. By deleting the last sentence of Section 8.4 of the Plan and inserting in lieu thereof the following:

"In the absence of an effective election, one hundred percent (100%) of the Participant's Employee Contributions and transfers to his or her Transfer Account shall be invested in the Fidelity Managed Income Portfolio, except that a Participant's Employee Contributions and transfers to his or her Transfer Account made on or after January 18, 2008 shall be invested, in absence of an effective election, one hundred percent (100%) in the applicable Fidelity Freedom Fund set forth below based upon the Participant's date of birth provided by the Participant to the Company and the applicable date of birth range (which Investment Funds are intended to be a "qualified default investment alternative" within the meaning of Department of Labor regulations), except that if a Participant fails to provide his or her date of birth to the Company, such amounts shall be invested in the Fidelity Freedom Income Fund:

Date of Birth Range	**Fidelity Freedom Fund Name**
01/01/1900 – 12/31/1932	Freedom Income
01/01/1933 – 12/31/1937	Freedom 2000
01/01/1938 – 12/31/1942	Freedom 2005
01/01/1943 – 12/31/1947	Freedom 2010
01/01/1948 – 12/31/1952	Freedom 2015
01/01/1953 – 12/31/1957	Freedom 2020
01/01/1958 – 12/31/1962	Freedom 2025
01/01/1963 – 12/31/1967	Freedom 2030
01/01/1968 – 12/31/1972	Freedom 2035
01/01/1973 – 12/31/1977	Freedom 2040
01/01/1978 – 12/31/1982	Freedom 2045
01/01/1983 – 12/31/1999	Freedom 2050."

13. By adding a new paragraph after the sixth paragraph of Section 10.3 of the Plan as follows:

"Notwithstanding the preceding two paragraphs, with respect to any Participant who completes an Hour of Service on or after March 1, 2008, the vested balance in the Company Matching Contribution Account of such Participant on or after March 1, 2008, will be determined based on the Participant's Vesting Percentage as specified in the Vesting Schedule below instead of the applicable Vesting Schedule provided above:

Vesting Schedule

Full Years of Vesting Service	Vesting Percentage
Less than 2 years	0%
2	20%
3	100%"

14. By deleting the seventh paragraph of Section 10.4 of the Plan and inserting in lieu thereof the following:

"Upon making a withdrawal described in subsection 10.4(h) above, the Participant shall be suspended from making further Employee Contributions to the Plan for a period of twelve months following such withdrawal and shall be deemed to terminate any Automatic Compensation Reduction Agreement then in effect."

15. By deleting the introductory clause of the first paragraph of Section 20.2(a) of the Plan and inserting in lieu thereof the following:

"A Participant's Vesting Percentage under Section 10.3 in his or her Company Matching Contribution Account shall be determined in accordance with the following schedule unless the Participant has an Hour of Service on or after March 1, 2008:".

IN WITNESS WHEREOF, the Company has caused this instrument to be signed by a duly authorized officer as of the 18th day of January, 2008.

OGE ENERGY CORP.

By: /s/ Cary W. Martin

Exhibit 10.35

Letter of extension for the Company’s credit agreement
Dated November 11, 2007

In accordance with Section 2.21 of the Company’s Credit Agreement dated December 6, 2006, Lenders holding Commitments aggregating $600 million have approved the extension of the Maturity Date (with respect to their Commitments only) for an additional year until December 6, 2012.

Exhibit 10.36

Letter of extension for OG&E's credit agreement
Dated November 11, 2007

In accordance with Section 2.21 of OG&E's Credit Agreement dated December 6, 2006, Lenders holding Commitments aggregating $400 million have approved the extension of the Maturity Date (with respect to their Commitments only) for an additional year until December 6, 2012.

Exhibit 12.01

OGE ENERGY CORP.
RATIO OF EARNINGS TO FIXED CHARGES

	Year Ended Dec 31, 2003	Year Ended Dec 31, 2004	Year Ended Dec 31, 2005	Year Ended Dec 31, 2006	Year Ended Dec 31, 2007
Earnings:					
Pre-tax income from continuing operations	$201,237,416	$215,289,482	$229,837,874	$346,559,601	$360,957,866
Add Fixed Charges	96,489,538	95,978,185	95,956,779	104,155,889	97,599,492
Subtotal	297,726,954	311,267,667	325,794,653	450,715,490	458,557,358
Subtract:					
Allowance for borrowed funds used during construction	538,624	1,661,732	2,232,715	4,486,530	3,989,406
Other capitalized interest	---	---	---	920,303	902,022
Total Earnings	297,188,330	309,605,935	323,561,938	445,308,657	453,665,930
Fixed Charges:					
Interest on long-term debt	87,348,025	83,094,306	79,951,032	88,287,021	88,677,365
Interest on short-term debt and other interest charges	5,488,788	9,359,056	12,570,711	13,107,379	6,444,257
Calculated interest on leased property	3,652,725	3,524,823	3,435,036	2,761,489	2,477,870
Total Fixed Charges	$96,489,538	$95,978,185	$95,956,779	$104,155,889	$97,599,492
Ratio of Earnings to Fixed Charges	3.08	3.23	3.37	4.28	4.65

Exhibit 21.01

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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

The above listed subsidiaries have been consolidated in the Registrant's financial statements. Certain of the Company's subsidiaries have been omitted from the list above in accordance with Rule 1–02(w) of Regulation S-X.

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. 333-104552) 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 26, 2008, with respect to the consolidated financial statements and schedule of OGE Energy Corp., and the effectiveness of internal control over financial reporting of OGE Energy Corp., included in the Annual Report (Form 10-K) for the year ended December 31, 2007.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 26, 2008

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, 2007; 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 PETER B. DELANEY, 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 9th day of January, 2008.

Peter B. Delaney, Chairman, Principal Executive Officer and Director	/ s / Peter B. Delaney
Herbert H. Champlin, Director	/ s / Herbert H. Champlin
Luke R. Corbett, Director	/ s / Luke R. Corbett
John D. Groendyke, Director	/ s / John D. Groendyke
Kirk Humphreys, Director	/ s / Kirk Humphreys
Robert Kelley, Director	/ s / Robert Kelley
Linda P. Lambert, Director	/ s / Linda P. Lambert
Robert O. Lorenz, Director	/ s / Robert O. Lorenz
Leroy C. Richie, Director	/ s / Leroy C. Richie
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 OKLAHOMA)

On the date indicated above, before me, Sharon Grigsby, 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 9th day of January, 2008.

/s/ Sharon Grigsby
Sharon Grigsby
Notary Public in and for the County
of Oklahoma, State of Oklahoma

My Commission Expires:
February 17, 2010

Exhibit 31.01

CERTIFICATIONS

I, Peter B. Delaney, 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 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; and

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 28, 2008

/s/ Peter B. Delaney

Peter B. Delaney
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 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; and

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 28, 2008

/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, 2007, 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 28, 2008

/s/ Peter B. Delaney
Peter B. Delaney
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 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, Natural Gas Transportation and Storage, Gathering and Processing and Marketing 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 counterparty default;

- General economic conditions, including the 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 currently and in the future;

- Financial or regulatory accounting principles or policies imposed by the FASB, the SEC, the FERC, state public utility commissions; the regional state committee which regulates the SPP; state entities which regulate natural gas transmission, gathering and processing and similar entities with regulatory oversight;

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

- Availability or cost of capital, including 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 16 of Notes to Consolidated Financial Statements of the

Company's Annual Report on Form 10-K for the year ended December 31, 2007, 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 SEC 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;

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

- Approval of future regulatory filings with the OCC or the APSC (including the approval of future regulatory filings related to the proposed acquisition of the Redbud power plant); and

- Discontinuance of regulated accounting principles under SFAS No. 71.

Natural Gas Transportation and Storage, Gathering and Processing and Marketing Segments

- 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;

- 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; and

- The impact of the proposed initial public offering of limited partner interests of OGE Enogex Partners L.P.

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.

Exhibit 10.28

OGE ENERGY CORP.
DIRECTORS' COMPENSATION

Compensation of non-officer directors of the Company during 2007 included an annual retainer fee of $86,000, of which $30,000 was payable monthly in cash and $56,000 was deposited in the director's account under the Company's Deferred Compensation Plan in December 2007 and converted to 1,573.034 common stock units based on the closing price of the Company's Common Stock on November 30, 2007. All non-officer directors received $1,200 for each Board meeting and $1,200 for each committee meeting attended. The lead director and the chairman of the audit committee each received an additional $10,000 cash retainer. The chairmen of the compensation and nominating and corporate governance committees received an additional $5,000 annual cash retainer in 2007. Each chairman of a board committee also received a meeting fee of $1,200 for each meeting (either in person or by phone) with management to address committee matters. Each member of the Audit Committee also received an additional annual retainer of $5,000. These amounts represent the total fees paid to directors in their capacities as directors of the Company and OG&E during 2007.

Under the Company's Deferred Compensation 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 as of the first of the month in which 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 Deferred Compensation Plan. During 2007, those investment options included an OGE Energy 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 Deferred Compensation Plan are paid in cash in a lump sum or installments.

In November 2007, the compensation committee met to consider director compensation. At that meeting, the compensation committee approved the $56,000 described above and approved an increase in the amount of the annual retainer payable monthly in cash to $35,000 beginning in January 2008.

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 November 1997, however, will continue to receive benefits under the former policy.

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February 28, 2008

Securities and Exchange Commission
Division of Corporation Finance
100 F Street, N.E.
Washington, D.C. 20549

Gentlemen:

On behalf of OGE Energy Corp., I am submitting to you via electronic filing, pursuant to Instruction D to Form 10-K, the Company's Form 10-K for the year ended December 31, 2007, including financial statements, financial statement schedules, exhibits and the power of attorney. The financial statements included in the Form 10-K reflect changes in accounting principles from the preceding year as the Company adopted Financial Accounting Standards Board Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109," and Financial Accounting Standards Board Interpretation No. 39 (As Amended), "Offsetting of Amounts Related to Certain Contracts – an interpretation of APB Opinion No. 10 and FASB Statement No. 105."

Very truly yours,

/s/ Scott Forbes
Scott Forbes
Controller