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, 2008

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 (§229.405 of this Chapter) 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.

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 30, 2008, the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of shares of common stock held by non-affiliates was $2,917,617,820 based on the number of shares held by non-affiliates (92,009,392) and the reported closing market price of the common stock on the New York Stock Exchange on such date of $31.71.

At January 31, 2009, 94,755,345 shares of common stock, par value $0.01 per share, were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The Proxy Statement for the Company's 2009 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, 2008

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FORWARD-LOOKING STATEMENTS

Except for the historical statements contained herein, the matters discussed in this 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" herein, 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, access to existing lines of credit, actions of rating agencies and their impact on capital expenditures;
- OGE Energy Corp.'s ("OGE Energy" and collectively, with its subsidiaries, the "Company") ability and the ability of its subsidiaries to access the capital markets and 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 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 ("FASB") Statement of Financial Accounting Standards ("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; 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 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 14 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 LLC and its subsidiaries ("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 former subsidiary, OGE Energy Resources, Inc. ("OERI"). On January 1, 2008, Enogex distributed the stock of OERI to OGE Energy. Also, Enogex holds a 50 percent ownership interest in the Atoka Midstream, LLC joint venture through Enogex Atoka LLC ("Atoka"), a wholly owned subsidiary of Enogex.

Effective April 1, 2008, Enogex Inc. converted from an Oklahoma corporation to a Delaware limited liability company. Also, effective April 1, 2008, Enogex Products Corporation ("Products"), a wholly owned subsidiary of Enogex, converted from an Oklahoma corporation to an Oklahoma limited liability company.

In September 2008, OGE Energy and Energy Transfer Partners, L.P. ("ETP") entered into an agreement to form a joint venture combining Enogex's midstream business with ETP's interstate operations as well as its midstream operations in the Rocky Mountains. One of the conditions to completing the joint venture was obtaining financing that met the minimum specified terms the parties had agreed to in the joint venture agreement. Under the terms of the agreement, if OGE Energy and ETP did not complete the financing and close the joint venture by March 31, 2009, either OGE Energy or ETP could terminate the contribution agreement relating to the formation of the joint venture. Due to the significant downturn in the national economy and resulting uncertainty in the capital markets, the parties determined that obtaining the financing and completing the formation of the joint venture was not feasible and not in their best interests. Accordingly, on February 12, 2009, the parties terminated the agreement to form the joint venture.

In light of the September 28, 2008 announcement of the proposed joint venture as well as market conditions, OGE Enogex Partners, L.P., a partnership formed by the Company to further develop Enogex's natural gas midstream assets and operations, which had previously filed a registration statement with the SEC for a proposed initial public offering of its common units, has determined not to proceed with the offering contemplated by the registration statement and withdrew the registration statement on September 23, 2008.

In July 2008, OGE Energy and Electric Transmission America, a joint venture of subsidiaries of American Electric Power and MidAmerican Energy Holdings Co., formed a transmission joint venture to construct high-capacity transmission line projects in western Oklahoma. The Company will own 50 percent of the joint venture. The joint venture is intended to allow the companies to lead development of renewable wind by sharing capital costs associated with the planned transmission construction. Work on the joint venture projects is scheduled to begin in late 2009 and is targeted for completion by the end of 2013. The joint venture projects are subject to creation by the Southwest Power Pool ("SPP") of a cost allocation method that would spread the total cost across the SPP region. OGE Energy filed an application with the FERC in October 2008 for cost recovery of these projects subject to SPP and FERC approval for these projects. On December 2, 2008, the FERC granted the joint venture's request for transmission rate incentives for the initial projects, established a base return on equity for initial projects, approved certain accounting treatments for the initial projects and set the formula rate and accompanying protocols for hearing and settlement discussions. The joint venture's initial projects will include 765 kilovolt lines from Woodward 120 miles northwest to Guymon in the Oklahoma Panhandle and from Woodward 50 miles north to the Kansas border. An SPP study estimates cost for the two projects to be approximately $500 million, of which OGE Energy's portion will be approximately $250 million.

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 natural 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, leverage unique geographic position to develop renewable energy resources for wind and transmission, 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;
- OGE Energy and Electric Transmission America, a joint venture of subsidiaries of American Electric Power and MidAmerican Energy Holdings Co., formed a transmission joint venture in July 2008 to construct high-capacity transmission line projects in western Oklahoma which is intended to allow the companies to lead development of renewable wind with the planned transmission construction from Woodward northwest to Guymon in the Oklahoma Panhandle and from Woodward north to the Kansas border;
- OG&E signed contracts on July 31, 2008 for approximately 101 MWs of wind turbine generators and certain related balance of plant engineering, procurement and construction services associated with a future wind project ("OU Spirit") in western Oklahoma which is expected to be in service by the end of 2009;
- OG&E purchased a 51 percent interest in the 1,230 MW natural gas-fired, combined-cycle power generation facility in Luther, Oklahoma (the "Redbud Facility") in September 2008;
- OG&E issued a request for proposal ("RFP") for wind power in December 2008 for up to 300 MWs of new capability which OG&E intends to add to its power-generation portfolio no later than the end of 2010; and
- OG&E's construction initiative from 2009 to 2014 includes approximately $2.7 billion in major projects designed to expand capacity, enhance reliability and improve environmental performance. This construction initiative also includes strengthening and expanding the electric transmission, distribution and substation systems and replacing aging infrastructure.

OG&E continues to pursue additional renewable energy and the construction of associated transmission facilities required to support this renewable expansion. In 2008, OG&E established a "Quick Start" Demand Side Management program to encourage more efficient use of electricity. OG&E also announced a "Positive Energy SmartPower" initiative (commonly referred to in the industry as "Smart Grid" technologies) that will empower customers to proactively manage their energy consumption during periods of peak demand. If these initiatives are successful, OG&E believes it may be able to defer the construction of any incremental fossil fuel generation capacity until 2020.

The increase in wind power generation and the building of the transmission lines are 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 16 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 Atoka joint venture; 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. At December 31, 2008, four 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 89 percent of its total electric operating revenues for the year ended December 31, 2008 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 2008 was approximately 6,472 MWs on August 4, 2008. OG&E's load responsibility peak demand was approximately 6,054 MWs on August 4, 2008. As reflected in the table below and in the operating statistics that follow, there were approximately 26.8 million megawatt-hour ("MWH") sales to OG&E's customers ("system sales") in 2008 and 26.4 million MWH system sales in both 2007 and 2006. Variations in system sales for the three years are reflected in the following table:

Year ended December 31 *(In millions)*	**2008**	**2008 vs. 2007 Increase**	2007	2007 vs. 2006 Increase	2006	2006 vs. 2005 Increase
System Sales (A)	**26.8**	**1.5%**	26.4	---%	26.4	1.5%

(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 16 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)*	**2008**	2007	2006
ELECTRIC ENERGY *(Millions of MWH)*			
Generation (exclusive of station use)	**25.7**	23.8	24.6
Purchased	**4.3**	5.2	3.9
Total generated and purchased	**30.0**	29.0	28.5
Company use, free service and losses	**(1.8)**	(1.9)	(2.1)
Electric energy sold	**28.2**	27.1	26.4

ELECTRIC ENERGY SOLD *(Millions of MWH)*			
Residential	**9.0**	8.7	8.7
Commercial	**6.5**	6.3	6.2
Industrial	**4.0**	4.2	4.4
Oilfield	**2.9**	2.8	2.7
Public authorities and street light	**3.0**	3.0	2.9
Sales for resale	**1.4**	1.4	1.5
System sales	**26.8**	26.4	26.4
Off-system sales	**1.4**	0.7	---
Total sales	**28.2**	27.1	26.4
ELECTRIC OPERATING REVENUES *(In millions)*			
Residential	**$ 751.2**	$ 706.4	$ 698.8
Commercial	**479.0**	450.1	428.3
Industrial	**219.8**	221.4	215.7
Oilfield	**151.9**	140.9	129.3
Public authorities and street light	**190.3**	181.4	171.0
Sales for resale	**64.9**	68.8	65.4
Provision for rate refund	**(0.4)**	0.1	(0.9)
System sales revenues	**1,856.7**	1,769.1	1,707.6
Off-system sales revenues	**68.9**	35.1	2.7
Other	**33.9**	30.9	35.4
Total Electric Operating Revenues	**$ 1,959.5**	$ 1,835.1	$ 1,745.7
ACTUAL NUMBER OF ELECTRIC CUSTOMERS *(At end of period)*			
Residential	**659,829**	653,369	647,548
Commercial	**85,030**	83,901	82,974
Industrial	**3,086**	3,142	3,181
Oilfield	**6,424**	6,324	6,324
Public authorities and street light	**15,670**	15,446	14,769
Sales for resale	**49**	52	44
Total	**770,088**	762,234	754,840
AVERAGE RESIDENTIAL CUSTOMER SALES			
Average annual revenue	**$ 1,145.05**	$ 1,086.03	$ 1,084.31
Average annual use (kilowatt-hour (“KWH”))	**13,659**	13,325	13,526
Average price per KWH (cents)	**$ 8.38**	$ 8.15	$ 8.02

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, 2008, approximately 88 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, nine percent to the APSC and three 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 16 of Notes to Consolidated Financial Statements.

Recent Regulatory Matters

Acquisition of Redbud 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 were 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 owned the 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 were subject to an order from the FERC authorizing the contemplated transactions and an order from the OCC approving the prudence of the transactions and an appropriate reasonable recovery mechanism, and other customary conditions.

On September 16, 2008, the FERC issued an order approving the Redbud acquisition. In the order, the FERC concluded that the Redbud acquisition could harm horizontal competition by increasing market concentration. However, the FERC concluded that, since OG&E had committed to construct specific upgrades on the system, these would be adequate mitigation measures. Accordingly, the FERC conditioned its approval of the Redbud acquisition on OG&E's completion of these upgrades. OG&E is required to file quarterly updates describing the progress of the transmission upgrades, the first of which was filed December 16, 2008. OG&E also must notify the FERC of any change in circumstances regarding these projects. During the approximately 27-month period required to construct the transmission upgrades, the FERC did not require any interim mitigation beyond the limits of OG&E's market-based rate authority and the SPP market monitoring programs currently in place. In addition, the FERC found that the proposed transaction would have no adverse effects on vertical market power, on wholesale rates, or on state or Federal regulation. The FERC also determined that the transaction presented no cross-subsidy concerns. Finally, the FERC rejected various arguments raised by AES Shady Point that sought to expand the scope of the FERC proceeding or to impose additional conditions on the Redbud acquisition. On September 24, 2008, the OCC issued an order approving the Redbud acquisition. OG&E closed on the Redbud acquisition on September 29, 2008. OG&E implemented a rider at the end of September 2008 to recover the Oklahoma jurisdiction revenue requirement until new rates are implemented that include Redbud's net investment, operation and maintenance expense, depreciation expense and ad valorem taxes.

Cancelled Red Rock Power Plant and Storm Cost Recovery Rider. 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 coal-fired 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. Specifically, OG&E requested authorization to sell approximately $14.7 million of its sulfur dioxide ("SO2") allowances and to retain 100 percent of the proceeds to offset the $14.7 million of Red Rock costs. Under a prior order of the OCC, 90 percent of the proceeds from sales of SO2 allowances were to be credited to ratepayers. Any portion of the $14.7 million of deferred costs that the OCC did not approve for recovery by OG&E was to be expensed. In its response to OG&E's Red Rock cost recovery application, the OCC Staff recommended, among other things, that OG&E sell SO2 allowances and retain 100 percent of the proceeds from the sale to be used to offset OG&E's December 2007 ice storm costs. These ice storm costs were included as part of the regulatory asset balance of approximately $35.9 million at December 31, 2007 (see Note 1), in accordance with a prior order of the OCC, pending recovery in a future rate case. On June 27, 2008, OG&E filed an application requesting a Storm Cost Recovery Rider ("SCRR") for the years 2007 through 2009 to recover excess storm damage costs and, at the same time, filed a motion to consolidate for hearing the Red Rock application and the SCRR application. On July 24, 2008, a settlement agreement was signed by all the parties involved in the two cases. Under the terms of the settlement agreement, OG&E will: (i) recover approximately $7.2 million, or 50 percent, of the Oklahoma jurisdictional portion of the Red Rock power plant deferred costs through a regulatory asset, (ii) amortize the Red Rock regulatory asset over a 27-year amortization period and earn the OCC's authorized rate of return beginning with OG&E's next rate case, (iii) accrue carrying costs on the debt portion of the Red Rock regulatory asset from October 1, 2007 until the date OG&E begins to recover the regulatory asset through the base rates established in OG&E's next rate case, (iv) recover the OCC Staff and Attorney General consulting fees of approximately $0.3 million related to the Red Rock pre-approval case, in OG&E's next rate case by amortizing this over a two-year period, (v) recover approximately $33.7 million of the 2007 storm costs regulatory asset, which resulted in a write-down of approximately $1.5 million, (vi) implement the SCRR to recover OG&E's actual storm expense for the four-year period from 2006 through 2009, (vii) retain the first $3.4 million from the sale of excess SO2 allowances, (viii) reduce storm costs recovered through the SCRR by the proceeds from the sale of SO2 allowances above the amount retained by OG&E and (ix) earn the most recent OCC authorized return on the unrecovered storm cost balance through the SCRR. On August 22, 2008, the OCC issued an order approving the settlement agreement and the SCRR was implemented in September 2008. In June 2008, OG&E wrote down the Red Rock deferred cost and the storm costs to their net present value, which resulted in a pre-tax charge of approximately $9.0 million, which is currently included in Deferred Charges and Other Assets with an offset in Other Expense on the Company's Consolidated Financial Statements.

Renewable Energy Filing. 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, on December 8, 2008, OG&E issued an RFP to wind developers for construction of up to 300 MWs of new capability. OG&E intends to add the new capacity to its power-generation portfolio no later than the end of 2010. See discussion of OG&E proposed wind power project below.

OG&E filed an application on May 19, 2008 with the OCC requesting pre-approval to recover from Oklahoma customers the cost to construct a transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma at a cost of approximately $211 million. This transmission line is a critical first step to increased wind development in western Oklahoma. In the application, OG&E also requested authorization to implement a recovery rider to be effective when the transmission line is completed and in service, which is expected during 2010. Finally, the application requested the OCC to approve new renewable tariff offerings to OG&E's Oklahoma customers. On July 11, 2008, the OCC Staff filed responsive testimony recommending approval of OG&E's renewable plan and the Oklahoma Industrial Energy Consumers opposed OG&E's request. A settlement agreement was signed by all parties in the matter on July 31, 2008. Under the terms of the settlement agreement, the parties agreed that OG&E will: (i) receive pre-approval for construction of a transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma and a conclusion that the construction costs of the transmission line are prudent, (ii) receive a recovery rider for the revenue requirement of the $218 million in construction costs and allowance for funds used during construction (“AFUDC”) when the transmission line is completed and in service until new rates are implemented in a subsequent rate case and (iii) to the extent the construction costs and AFUDC for the transmission line exceed $218 million OG&E be permitted to show that such additional costs are prudent and allowed to be recovered. On September 11, 2008, the OCC issued an order approving the settlement agreement. Separately, on July 29, 2008, the SPP Board of Directors approved the proposed transmission line discussed above. On February 2, 2009, OG&E received SPP approval to begin construction of the transmission line and the associated Woodward Extra High Voltage substation.

OG&E Arkansas Rate Case Filing. On August 29, 2008, OG&E filed with the APSC an application for an annual rate increase of approximately $26.4 million to recover, among other things, costs for investments including the Redbud Facility and improvements in its system of power lines, substations and related equipment to ensure that OG&E can reliably meet growing customer demand for electricity, and a return on equity of 12.25 percent. In January 2009, the APSC Staff recommended a $12.0 million rate increase based on a 10.5 percent return on equity. The Attorney General’s consultant recommended a return on equity at the current authorized level of 10.0 percent and stated that his analysis identified at least $10.9 million in reductions to OG&E’s rate increase request. A hearing is scheduled for April 7, 2009. An order from the APSC is expected in June 2009, with new rates targeted for implementation in July 2009.

OG&E 2009 Oklahoma Rate Case Filing. Beginning in October 2008, OG&E began developing a rate case filing for the Oklahoma jurisdiction. On January 20, 2009, OG&E notified the OCC that it will make its planned Oklahoma rate case filing on or about February 26, 2009. OG&E is finalizing the preparation of the rate case and expects to request an increase of between $100 million and $110 million. The case is expected to proceed through the first half of 2009. If an increase is approved by the OCC, electric rates would likely be implemented in September 2009 at the earliest.

OG&E Proposed Wind Power Project. OG&E signed contracts on July 31, 2008 for approximately 101 MWs of wind turbine generators and certain related balance of plant engineering, procurement and construction services associated with the future OU Spirit wind project in western Oklahoma. OG&E will seek regulatory recovery from the OCC and plans to have this project in-service by the end of 2009. Capital expenditures associated with this project are expected to be approximately $260 million.

OGE Energy and Electric Transmission America Joint Venture. As discussed above, the joint venture is intended to allow the companies to lead development of renewable wind by sharing capital costs associated with the planned transmission construction. Work on the joint venture projects is scheduled to begin in late 2009 and is targeted for completion by the end of 2013. The joint venture projects are subject to creation by the SPP of a cost allocation method that would spread the total cost across the SPP region. OGE Energy filed an application with the FERC in October 2008 for cost recovery of these projects subject to SPP and FERC approval for these projects. On December 2, 2008, the FERC granted the joint venture’s request for transmission rate incentives for the initial projects, established a base return on equity for initial projects, approved certain accounting treatments for the initial projects and set the formula rate and accompanying protocols for hearing and settlement discussions. The joint venture’s initial projects will include 765 kilovolt lines from Woodward 120 miles northwest to Guymon in the Oklahoma Panhandle and from Woodward 50 miles north to the Kansas border. An SPP study estimates cost for the two projects to be approximately $500 million, of which OGE Energy’s portion will be approximately $250 million.

See Note 16 of Notes to Consolidated Financial Statements for further discussion of these matters, as well as a discussion of additional regulatory matters, including, among other things, review of OG&E’s fuel adjustment clause, OG&E FERC formula rate filing, OG&E 2008 storm cost filing, 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, 2008 and 2007, OG&E had regulatory assets of approximately $464.3 million and $330.7 million, respectively, and regulatory liabilities of approximately $164.0 million and $148.2 million, respectively. See Note 1 of Notes to Consolidated Financial Statements for a further discussion.

As discussed in Note 16 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 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 a gain from the GFB option of approximately $3.0 million, $4.2 million and $0.6 million, respectively, in 2008, 2007 and 2006. Revenue variations may occur in the future based upon changes in customers' usage characteristics if they choose alternative rate options.

OG&E also has two additional 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. OG&E also created service level fuel differentiation that allows customers to pay fuel costs that better reflect operational energy losses related to a specific service level. Lastly, OG&E also implemented a military base rider that demonstrates Oklahoma's continued commitment to our military partners.

Fuel Supply and Generation

During 2008, approximately 68 percent of the OG&E-generated energy was produced by coal-fired units, 30 percent by natural gas-fired units and two percent by wind-powered units. Of OG&E's 6,781 total MW capability reflected in the table under Item 2. Properties, approximately 4,119 MWs, or 61 percent, are from natural gas generation, approximately 2,542 MWs, or 37 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. 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	**2008**	2007	2006	2005	2004
Coal	**$ 1.11**	$ 1.10	$ 1.10	$ 0.98	$ 1.00
Natural Gas	**$ 8.40**	$ 6.77	$ 7.10	$ 8.76	$ 6.57
Weighted Average	**$ 3.30**	$ 3.13	$ 2.98	$ 3.21	$ 2.69

The increase in the weighted average cost of fuel in 2008 as compared to 2007 was primarily due to increased natural gas prices partially offset by decreased amounts of natural gas being burned. 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 fuel adjustment clauses that are approved by the OCC and the APSC. See Note 15 of Notes to Consolidated Financial Statements for a discussion of new and pending coal transportation contracts that will increase OG&E's delivered coal prices.

Coal

All of OG&E's coal-fired units, with an aggregate capability of approximately 2,542 MWs, are designed to burn low sulfur western coal. OG&E purchases coal primarily under contracts expiring in years 2010 and 2011. During 2008, OG&E purchased approximately 10.5 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 1.2 lbs. of SO2 per MMBtu) without the addition of SO2 removal systems. Based upon the average sulfur content, OG&E's coal units have an approximate emission rate of 0.52 lbs. of SO2 per MMBtu, well within the limitations of the current provisions of the Federal Clean Air Act discussed in Note 15 of Notes to Consolidated Financial Statements.

OG&E has continued its efforts to maximize the utilization of its coal-fired units at its Sooner and Muskogee generating plants. See "Environmental Laws and Regulations" in Note 15 of Notes to Consolidated Financial Statements for a discussion of environmental matters which may affect OG&E in the future.

Natural Gas

In August 2008, OG&E issued an RFP for gas supply purchases for periods from November 2008 through March 2009, which accounted for approximately 15 percent of its projected 2009 natural gas requirements. The contracts resulting from this RFP are tied to various gas price market indices that will expire in 2009. Additional gas supplies to fulfill OG&E's remaining 2009 natural gas requirements will be acquired through additional RFPs in early to mid-2009, 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, 2008, OG&E had approximately 1.9 million MMBtu's in natural gas storage that it acquired for approximately $11.5 million.

Wind

OG&E's current wind power portfolio includes the 120 MW Centennial wind farm placed in service in January 2007 as well as access to up to 50 MWs of electricity generated at a wind farm near Woodward, Oklahoma from a 15-year contract OG&E entered into with FPL Energy in 2003.

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, on December 8, 2008, OG&E issued an RFP to wind developers for construction of up to 300 MWs of new capability. OG&E intends to add the new capacity to its power-generation portfolio no later than the end of 2010.

OG&E signed contracts on July 31, 2008 for approximately 101 MWs of wind turbine generators and certain related balance of plant engineering, procurement and construction services associated with the future OU Spirit wind project in western Oklahoma. OG&E will seek regulatory recovery from the OCC and plans to have this project in-service by the end of 2009. Capital expenditures associated with this project are expected to be approximately $260 million.

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 it 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 former subsidiary, OERI. 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 2,433 miles of intrastate natural gas transportation pipelines with approximately 1.57 trillion British thermal units per day ("TBtu/d") of average daily throughput during 2008. Enogex also owns and operates two storage facilities currently being operated at a working gas level of approximately 24 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, 2008, Enogex was connected to 11 third-party natural gas pipelines and had 63 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, Quest Pipelines (KPC) and Ozark Gas Transmission, L.L.C. Further, Enogex is connected to 24 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 24 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 and the OG&E contract provide for a monthly demand charge plus variable transportation charges (including fuel). The PSO contract expires January 1, 2013, unless extended. The stated term of the OG&E contract expires April 30, 2009, but the contract will remain in effect from year to year thereafter unless either party provides written notice of termination to the other party at least 180 days prior to the commencement of the next succeeding annual period. Because neither party provided notice of termination 180 days prior to May 1, 2009, the contract will remain in effect at least through April 30, 2010. 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 2006, 2007 and 2008, revenues from Enogex’s firm intrastate transportation and storage contracts were approximately $98.1 million, $103.9 million and $104.4 million, respectively, of which approximately $47.6 million, $47.4 million and $47.5 million, respectively, was attributed to OG&E and $13.3 million, $13.3 million and $15.3 million, respectively, was attributed to PSO. Revenues from Enogex’s firm intrastate transportation and storage contracts represented approximately 31 percent of Enogex’s consolidated gross margin on revenues (“gross margin”) in 2006, 29 percent in 2007 and 27 percent in 2008.

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.

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. By order of February 28, 2008, the FERC extended the time period in this docket by 120 days and encouraged the parties to settle. No action has yet been taken by the FERC and the parties are currently in settlement negotiations.

On November 13, 2007, one of the protesting intervenors filed to consolidate the Enogex rate case with a separate Enogex application pending before the FERC allowing Enogex to lease firm capacity to MEP and with separate applications filed by MEP with the FERC for a certificate to construct and operate the new MEP pipeline and to lease firm capacity from Enogex. Additional pleadings were also filed by this intervenor after the initial protest and Enogex and MEP separately opposed this intervenor's assertions. By order dated July 25, 2008, the FERC approved the MEP project and denied the intervenors' request for consolidation of the MEP proceedings with the Enogex rate case. The intervenor has filed a request for rehearing in the MEP project and lease proceedings. The FERC has not yet acted on the request. Enogex has not, as of yet, placed the increased rates into effect while settlement negotiations continue. Enogex has a regulatory obligation to file its next rate case no later than October 1, 2010 to comply with the FERC's requirement for triennial filings, but plans to file a new rate case during the first half of 2009. While Enogex has yet to finalize various components of the new filing, Enogex is finalizing agreements with East Zone shippers interested in firm Section 311 service on the East Zone of its system and anticipates offering in the near-term a limited firm Section 311 service on the East Zone for the first time.

On November 21, 2008, Enogex made its annual filing to establish fixed fuel percentages for its East Zone and West Zone, respectively, for calendar year 2009 ("2009 Fuel Year"). The FERC accepted the proposed zonal fuel percentages for the 2009 Fuel Year by an order dated January 8, 2009.

The 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. Therefore, 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 ("DOT") has adopted regulations requiring pipeline operators to develop integrity management programs for its transportation pipelines. During 2008, Enogex incurred approximately $7.9 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 $35.7 million between 2009 and 2013 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 MEP for a primary term of ten 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 272 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 MEP project includes construction by MEP of a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. Enogex currently estimates that its capital expenditures related to this project will be approximately $94 million.

On July 25, 2008, the FERC issued its order approving the MEP project including the approval of a limited jurisdiction certificate authorizing the Enogex lease agreement to MEP. Further, the FERC order rejected all claims raised by protestors regarding the lease agreement. Accordingly, Enogex is proceeding with the construction of facilities necessary to implement this service. On August 25, 2008, one protestor filed a request for rehearing. The FERC has not yet ruled on the request for rehearing. The MEP project is currently expected to be in service during the second quarter of 2009.

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 NGLs.

Enogex's gathering system includes approximately 5,763 miles of natural gas gathering pipelines with approximately 1.16 TBtu/d of average daily throughput during 2008 extending from southwestern Oklahoma to the eastern Texas Panhandle. During 2008, Enogex connected 357 new producing wells (including 154 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, 2008, Enogex's gathering system was connected to approximately 3,278 wells and approximately 266 central receipt points, all of which are equipped with state-of-the-art electronic flow measurement technology. Approximately 74 percent of Enogex's gathered volumes are received at wellheads while 26 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, has a 50 percent interest in and operates an additional natural gas processing plant with an inlet capacity of approximately 20 MMcf/d and has access to capacity up to 50 MMcf/d in two third-party plants, 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 or the two leased plants. 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, 2008, Enogex extracted and sold approximately 426 million gallons of NGLs.

In 2007, 2008 and 2009, 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 two compression turbines at the Thomas processing plant, which allowed for the realization of fuel savings at that plant.

- Enogex will consider building or acquiring additional processing capacity in areas where the capacity is needed. Enogex completed construction of a new 100 MMcf/d refrigeration dew point conditioning plant in Roger Mills County of Oklahoma, which became operational in August 2008. In addition, Enogex is constructing 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 by mid-2009.

Enogex's gathering and processing business has approximately 276,000 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. 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, 2008, these arrangements accounted for approximately ten 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. At December 31, 2008, these arrangements accounted for approximately 36 percent of Enogex's natural gas processed volumes.
- *Keep-Whole Arrangements*. Enogex processes raw natural gas to extract NGLs and returns 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 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 conditioning floors (such as the default processing fee described below) that allow the keep-whole contract to be charged a fee if the NGLs have a lower value than their gas equivalent Btu value in natural gas. At December 31, 2008, these arrangements accounted for approximately 54 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 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 17 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, 2008, approximately 3,278 wells and approximately 266 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, PSO and other independent power producers or (b) into downstream interstate pipelines. Enogex's NGLs are typically sold to NGL marketers and end users, 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, Devon Gas Services, L.P., Samson Resources Company and Cimarex Energy Co. During 2008, these five customers accounted for approximately 20 percent, 15 percent, nine percent, four percent and three percent, respectively, of Enogex's gathering and processing volumes. During 2008, Enogex's top ten natural gas producer customers accounted for approximately 65 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. To date, neither the Competition Bill nor the LUG Bill has had a significant impact on Enogex's operations. However, Enogex cannot predict what effect, if any, either the Competition Bill or the LUG Bill might have on its gathering operations in the future.

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, 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 2008, 2009 and 2010. 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, which resulted in the formation of the Atoka joint venture. Atoka 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 and acts as the managing member and operator of the facilities owned by the joint venture. The joint venture plans to expand its infrastructure in order to accommodate an anticipated increase in production in the area which is expected to require additional compression and processing capacity, as well as additional suction, discharge and well connect pipe. The current expansion project, including timing, is still under development. The capital expenditures associated with the expansion of Atoka are expected to be approximately $20 million. In addition, in order to accommodate the increased drilling activity in Canadian County, Oklahoma, Enogex plans to add approximately six miles of 12-inch steel pipe and another 10 MMcf/d of compression capacity to Enogex's Grandview gathering project in 2009. The capital expenditures associated with the additional pipe and compression capacity are expected to be approximately $9 million.

In February 2008, Enogex completed construction of a new 20-mile pipeline project that connects 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 75 MMcf/d for customers desiring low-pressure services. The pipeline is complemented by approximately 16,000 horsepower of new gathering compression which was completed in the third quarter of 2008. Also, Enogex is planning to add approximately 16 miles of 20-inch steel pipe and 60 MMcf/d of additional treating facilities. Under the assumed operating conditions, the gathering pipe is expected to have throughput capacity of approximately 300 MMcf/d and is expected to be in service by June 2009. The capital expenditures associated with the additional pipe and treating facilities are expected to be approximately $20 million.

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. Since the pipeline was put in service, Enogex has completed the construction of five new gas gathering compressor stations totaling approximately 26,500 horsepower of compression, and several miles of gathering pipe, including a new 16-inch line that extends the original pipeline project an additional 20 miles to the west. Enogex is continuing to expand in the Wheeler and Hemphill counties in Texas and expects to add another 16,000 horsepower of low pressure compression to the Wheeler area by October 2009.

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.

- In July 2008, Enogex completed implementation of an information system to support its NGLs business. The system is expected to strengthen compliance capabilities, evaluate Enogex's risk position, manage Enogex's credit exposure, improve invoicing accuracy and provide for easier data extraction in support of work activities and decision making.
- Enogex continues to improve its 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.
- An information system which has been implemented, together with Enogex's primary enterprise-wide general ledger software, and 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.

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 ten years. The 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

On January 1, 2008, 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, 2006, 2007 and 2008, OERI recorded revenues from Enogex of approximately $107.1 million, $95.2 million and $41.7 million, respectively, for the sale, at market rates, of natural gas. For the years ended December 31, 2006, 2007 and 2008, Enogex recorded revenues from OERI of approximately $291.9 million, $304.3 million and $307.2 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 pays Enogex a fee for certain back office functions and administrative 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 decreased from approximately 0.7 Bcf in 2007 to approximately 0.6 Bcf in 2008. This reflects selective deal execution to assure adequate margin in light of credit and other risks in the current commodity price and credit 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, 2008, approximately 65.0 percent of OERI's service volumes were with electric utilities, local gas distribution companies, pipelines and producers, of which approximately 26.0 percent was with affiliates of OERI. The remaining 35.0 percent of service volumes were to marketers, municipals, cooperatives and industrials. At December 31, 2008, approximately 64.0 percent of the payment exposure was to companies having investment grade ratings with Standard & Poor's Ratings Services ("Standard & Poor's") and approximately 1.7 percent having less than investment grade ratings. The remaining 34.3 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. 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. OG&E and Enogex handle some materials subject to the requirements of the Federal Resource Conservation and Recovery Act and the Federal Water Pollution Control Act of 1972, as amended ("Clean Water Act") and comparable state statutes, prepare and file reports and documents pursuant to the Toxic Substance Control Act and the Emergency Planning and Community Right to Know Act and obtain permits pursuant to the Federal Clean Air Act and comparable state air statutes.

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 $1.6 million of the Company's capital expenditures budgeted for 2009 are to comply with environmental laws and regulations, of which approximately $1.0 million and $0.6 million are related to OG&E and Enogex, respectively. Approximately $32.1 million of the Company's capital expenditures budgeted for 2010 are to comply with environmental laws and regulations, of which approximately $31.5 million and $0.6 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 $35.7 million and $4.3 million, respectively, during 2009 as compared to approximately $37.1 million and $3.6 million, respectively, during 2008. 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 15 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. 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, install emission control equipment 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. See Note 15 of Notes to Consolidated Financial Statements for a discussion of potentially significant environmental capital expenditures related to air emissions.

Water Discharges

OG&E's and Enogex's operations are subject to the 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. See Note 15 of Notes to Consolidated Financial Statements for a discussion of water intake matters.

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. The enactment of climate control laws or regulations 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. 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. Enogex is a partner in the EPA Natural Gas STAR Program, a voluntary program to reduce methane emissions.

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 expected to be primarily related to maturing debt, operating lease obligations, hedging activities, delays in recovering unconditional fuel purchase obligations, fuel clause under and over recoveries and other general corporate purposes. 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. However, OGE Energy's and OG&E's ability to access the commercial paper market was adversely impacted by the market turmoil that began in September 2008. Accordingly, in order to ensure the availability of funds, OGE Energy and OG&E utilized borrowings under their revolving credit agreements which bear a higher interest rate and a minimum 30-day maturity compared to commercial paper which had historically been available at lower interest rates and on a daily basis. OGE Energy and OG&E expect to repay the borrowings under their revolving credit agreements and begin utilizing commercial paper in the commercial paper market when available. 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 2009 to 2014 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: 2009 - $872.0 million, 2010 - $593.4 million, 2011 - $681.0 million, 2012 - $652.8 million, 2013 - $692.3 million and 2014 - $607.3 million. These capital expenditures include expenditures related to: (i) the proposed transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma, (ii) OGE Energy's portion of the proposed transmission projects as part of a newly formed transmission joint venture, (iii) OG&E's proposed 101 MW OU Spirit wind power project in western Oklahoma, (iv) OG&E's proposed system hardening plan and (v) OG&E's transmission/substation SPP project (see Note 16 of Notes to Consolidated Financial Statements for a further discussion). These capital expenditures exclude any environmental expenditures associated with Best Available

Retrofit Technology ("BART") requirements. As discussed in Note 15 of Notes to Consolidated Financial Statements, due to comments from the EPA that OG&E's proposed initial BART compliance plan would not satisfy the applicable requirements, OG&E completed additional analysis. On May 30, 2008, OG&E filed the results with the Oklahoma Department of Environmental Quality ("ODEQ") for the affected generating units. In the May 30, 2008 filing, OG&E indicated its intention to install low nitrogen oxide ("NOX") combustion technology at its affected generating stations and to continue to burn low sulfur coal at its four coal-fired generating units at its Muskogee and Sooner generating stations. The capital expenditures associated with the installation of the low NOX combustion technology are expected to be approximately $110 million. OG&E believes that these control measures will achieve visibility improvements in a cost-effective manner. OG&E did not propose the installation of scrubbers at its four coal-fired generating units because OG&E concluded that, consistent with the EPA's regulations on BART, the installation of scrubbers (at an estimated cost of $1.7 billion) would not be cost-effective. OG&E previously reported an expectation that a compliance plan would be approved by the EPA by December 31, 2008; however, submission of the overall compliance plan by the ODEQ (which will include OG&E's compliance plan previously submitted to the ODEQ) has been delayed and the current timing of the EPA approval cannot be reasonably predicted. In a letter dated November 4, 2008, the EPA notified the ODEQ that they had completed their review of BART applications for all affected sources in Oklahoma, which included OG&E. The EPA did not approve or disapprove the applications, however, additional information was requested from the ODEQ by the EPA regarding OG&E's plan. The Company cannot predict what action the EPA or the ODEQ will take in response to OG&E's May 30, 2008 filing or the November 4, 2008 letter from the EPA. Until the compliance plan is approved, the total cost of compliance, including capital expenditures, cannot be estimated by OG&E with a reasonable degree of certainty. Due to this uncertainty regarding BART costs, the Company has excluded any BART costs from the foregoing capital expenditure estimates. OG&E also has approximately 440 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

During both 2008 and 2007, the Company made contributions to its pension plan of approximately $50.0 million to help ensure that the pension plan maintains an adequate funded status. During 2009, 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 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.

Short-Term Debt

Short-term borrowings generally are used to meet working capital requirements. At December 31, 2008, the Company had approximately $298.0 million in outstanding borrowings under its revolving credit agreements and no outstanding commercial paper borrowings. At December 31, 2007, the Company had approximately $295.0 million in outstanding commercial paper borrowings and no outstanding borrowings under its revolving credit agreements. OGE Energy's and OG&E's ability to access the commercial paper market was adversely impacted by the market turmoil that began in September 2008. Accordingly, in order to ensure the availability of funds, OGE Energy and OG&E utilized borrowings under their revolving credit agreements, which generally bear a higher interest rate and a minimum 30-day maturity compared to commercial paper, which has historically been available at lower interest rates and on a daily basis. However, in late 2008, OGE Energy's and OG&E's revolving credit borrowings had a lower interest rate than commercial paper due to disruptions in the credit markets. In December 2008, OG&E repaid the outstanding borrowings under its revolving credit agreement with a portion of the proceeds received from the issuance of long-term debt in December. OG&E intends to utilize commercial paper in the commercial paper market when available. OGE Energy expects to repay the borrowings under its revolving credit agreement and begin utilizing the commercial paper market when available. 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, 2009 and ending December 31, 2010. See Note 12 of Notes to the Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

Long-Term Debt

On April 1, 2008, Enogex entered into a $250 million unsecured five-year revolving credit facility. Subject to certain limitations, the facility provides Enogex with the option, exercisable annually, to extend the maturity of the facility for an additional year and, upon the expiration of the revolving term, an option to convert the outstanding balance under the facility to a one-year term loan. The facility provides the option for Enogex to increase the borrowing limit by up to an additional $250 million (to a maximum of $500 million) upon the agreement of the lenders (or any additional lender) and the satisfaction of other specified conditions. This bank facility is available to provide revolving credit borrowings. At December 31, 2008, Enogex had approximately $120.0 million outstanding under this facility. These borrowings are not expected to be repaid within the next 12 months, therefore, they are classified as long-term debt for financial reporting purposes.

EMPLOYEES

The Company and its subsidiaries had 3,441 employees at December 31, 2008.

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 LLC 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.

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. Although OG&E has several rate proceedings currently pending, and expects to file a general rate case in Oklahoma shortly, 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, consolidated 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 U.S. Supreme Court decision holding that the EPA has the authority to regulate carbon dioxide emissions from motor vehicles under the Federal 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. 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 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 15 of Notes to Consolidated Financial Statements for a further discussion.

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 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, consolidated 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 possible impairments 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 the 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 the 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 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. 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. By order of February 28, 2008, the FERC extended the time period in this docket by 120 days and encouraged the parties to settle. No action has yet been taken by the FERC and the parties are currently in settlement negotiations. 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 2008, Enogex incurred approximately $7.9 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 $35.7 million between 2009 and 2013 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, consolidated 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, consolidated 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 significant 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.

Economic conditions could negatively impact our business.

Our operations are affected by local, national and worldwide economic conditions. The consequences of a prolonged recession could include a lower level of economic activity and uncertainty regarding energy prices and the capital and commodity markets. A lower level of economic activity could result in a decline in energy consumption, which could adversely affect our revenues and future growth. Instability in the financial markets, as a result of recession or otherwise, also could affect the cost of capital and our ability to raise capital.

Current economic conditions may be exacerbated by insufficient financial sector liquidity leading to potential increased unemployment, which could impact the ability of our customers to pay timely, increase customer bankruptcies, and could lead to increased bad debt. If such circumstances occur, we expect that commercial and industrial customers would be impacted first, with residential customers following.

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.

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. In 2008, the same index ranged from a high of $11.07 per MMBtu to a low of $2.81 per MMBtu. Natural gas prices reached relatively high levels in mid-2008 due to the impact of rising demand for natural gas but have returned to the near $4.50 per MMBtu level due to a rapid decline in demand for natural gas. 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 2007 ranged from a high of $1.52 per gallon to a low of $0.87 per gallon. In 2008, the same index ranged from a high of $1.76 per gallon to a low of $0.70 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 and OERI's revenue and cash flows.

The markets and prices for natural gas and NGLs depend upon factors beyond Enogex's and OERI's control and changes in these prices could adversely affect Enogex's and OERI'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 23 percent of its gross margin and accounted for approximately 54 percent of its natural gas processed volumes during 2008, 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 nine percent of its gross margin and accounted for approximately 36 percent of its natural gas processed volumes during 2008. 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 mid-2008 due to the impact of rising demand for natural gas but have returned to the near $4.50 per MMBtu level due to a rapid decline in demand for natural gas. 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, access to credit, 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 and OERI engage in commodity hedging activities to minimize the impact of commodity price risk, which may have a volatile effect on their earnings and cash flows.

Enogex and OERI are exposed to changes in commodity prices in their operations. To minimize the risk of commodity prices, Enogex and OERI 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 and OERI's inability to fulfill contractual obligations and incurrence of significantly higher energy or fuel costs relative to corresponding sales contracts. Enogex and OERI marks their derivative contracts to estimated fair market value. 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 and OERI engage 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 and OERI utilize 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 and NGL 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 and OERI'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 and OERI'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, 2008, Enogex had hedged approximately 65 percent of its expected non-ethane NGL volumes attributable to these arrangements, along with the natural gas MMBtu equivalent for keep-whole volumes, for 2009 through 2011, including approximately 86 percent for 2009, 77 percent for 2010 and 37 percent for 2011. As of December 31, 2008, Enogex had not hedged any of its expected ethane volumes attributable to these arrangements, along with the natural gas MMBtu equivalent for keep-whole volumes, for 2009. Enogex has the option to reject ethane if processing it is not economical. Management will continue to 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 2008, Chesapeake Energy Marketing Inc., Apache Corporation, Devon Gas Services, L.P., Samson Resources Company and Cimarex Energy Co. 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 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 2006, 2007 and 2008, revenues from Enogex's firm intrastate transportation and storage contracts were approximately $98.1 million, $103.9 million and $104.4 million, respectively, of which $47.6 million, $47.4 million and $47.5 million, respectively, was attributed to OG&E and $13.3 million, $13.3 million and $15.3 million, respectively, was attributed to PSO. Enogex's current contract with PSO expires January 1, 2013, unless extended. The stated term of Enogex's current contract with OG&E expires April 30, 2009, but the contract will remain in effect from year to year thereafter unless either party provides written notice of termination to the other party at least 180 days prior to the commencement of the next succeeding annual period. Because neither party provided notice of termination 180 days prior to May 1, 2009, the contract will remain in effect at least through April 30, 2010. 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, processing 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 to 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

Market performance, increased retirements, changes in retirement plan regulations and increasing costs associated with our defined benefit retirement plans, health care plans and other employee-related benefits may adversely affect our results of operations, consolidated 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, 2008, we expect to continue to make future contributions to maintain required funding levels; however, as our plans have experienced adverse market returns on investments in 2008 due to the recent turmoil in the financial markets, this could cause our future contributions to rise substantially over historical 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.

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 alters the manner in which pension plan assets and liabilities are valued for purposes of calculating required pension contributions, 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 were 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. See Note 13 of Notes to Consolidated Financial Statements for a further discussion of changes made to the Company's plans in order to comply with the Pension Protection Act.

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, consolidated 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 27 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, 2008, the Company and its subsidiaries had outstanding indebtedness and other liabilities of approximately $4.6 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 recent market turmoil. 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 additional 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.

Our debt levels may limit our flexibility in obtaining additional financing and in pursuing other business opportunities.

We have revolving credit agreements for working capital, capital expenditures, including acquisitions, and other corporate purposes. The levels of our 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 and future business opportunities; and
- our debt levels may limit our flexibility in responding to changing business and economic conditions.

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 ten generating stations with an aggregate capability of approximately 6,781 MWs at December 31, 2008. 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	2008 Capacity Factor (A)	Unit Capability (MW)	Station Capability (MW)
Muskogee	3	1956	Steam-Turbine	Gas	Base Load	10.9%	171	
	4	1977	Steam-Turbine	Coal	Base Load	78.0%	477	
	5	1978	Steam-Turbine	Coal	Base Load	62.5%	517	
	6	1984	Steam-Turbine	Coal	Base Load	73.2%	502	1,667
Seminole	1	1971	Steam-Turbine	Gas	Base Load	19.2%	464	
	1GT	1971	Combustion-Turbine	Gas	Peaking	---%(B)	17	
	2	1973	Steam-Turbine	Gas	Base Load	27.6%	494	
	3	1975	Steam-Turbine	Gas/Oil	Base Load	78.7%	502	1,477
Sooner	1	1979	Steam-Turbine	Coal	Base Load	87.4%	522	
	2	1980	Steam-Turbine	Coal	Base Load	77.5%	524	1,046
Horseshoe	6	1958	Steam-Turbine	Gas/Oil	Base Load	22.2%	171	
Lake	7	1963	Combined Cycle	Gas/Oil	Base Load	19.2%	227	
	8	1969	Steam-Turbine	Gas	Base Load	3.6%	380	
	9	2000	Combustion-Turbine	Gas	Peaking	3.1%(B)	46	
	10	2000	Combustion-Turbine	Gas	Peaking	3.2%(B)	46	870
Mustang	1	1950	Steam-Turbine	Gas	Peaking	0.6%(B)	54	
	2	1951	Steam-Turbine	Gas	Peaking	0.6%(B)	50	
	3	1955	Steam-Turbine	Gas	Base Load	17.8%	113	
	4	1959	Steam-Turbine	Gas	Base Load	25.2%	251	
	5A	1971	Combustion-Turbine	Gas/Jet Fuel	Peaking	0.4%(B)	32	
	5B	1971	Combustion-Turbine	Gas/Jet Fuel	Peaking	0.5%(B)	32	532
Redbud (C)	1	2003	Combined Cycle	Gas	Base Load	32.8%	163	
	2	2003	Combined Cycle	Gas	Base Load	32.8%	163	
	3	2003	Combined Cycle	Gas	Base Load	32.7%	163	
	4	2003	Combined Cycle	Gas	Base Load___%	32.7%	163	652
McClain (D)	1	2001	Combined Cycle	Gas	Base Load	55.9%	363	363
Woodward	1	1963	Combustion-Turbine	Gas	Peaking	0.1%(B)	10	10
Enid	1	1965	Combustion-Turbine	Gas	Peaking	0.1%	11	
	2	1965	Combustion-Turbine	Gas	Peaking	---%	11	
	3	1965	Combustion-Turbine	Gas	Peaking	---%	11	
	4	1965	Combustion-Turbine	Gas	Peaking	0.1%	11	44
Total Generating Capability (all stations, excluding winds station)								6,661

Station	Year Installed	Location	Number of Units	Fuel Capability	2008 Capacity Factor (A)	Unit Capability (MW)	Station Capability (MW)
Centennial	2007	Woodward, OK	80	Wind	40.7%	1.5	120.0
Total Generating Capability (wind station)							120.0

(A) 2008 Capacity Factor = 2008 Net Actual Generation / (2008 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) The original units at the Redbud Facility were installed in 2003. In September 2008, OG&E purchased a 51 percent ownership interest in the Redbud Facility. The capacity factor for the Redbud Facility shown above represents the capacity factor since OG&E's ownership.

(D) Represents OG&E's 77 percent ownership interest in the McClain Plant.

At December 31, 2008, OG&E's transmission system included: (i) 48 substations with a total capacity of approximately 9.9 million kilo Volt-Amps ("kVA") and approximately 4,029 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's distribution system included: (i) 348 substations with a total capacity of approximately 8.8 million kVA, 24,472 structure miles of overhead lines, 1,591 miles of underground conduit and 9,933 miles of underground conductors in Oklahoma; and (ii) 37 substations with a total capacity of approximately 1.0 million kVA, 1,901 structure miles of overhead lines, 162 miles of underground conduit and 651 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, 2008, Enogex and its subsidiaries owned: (i) approximately 5,763 miles of intrastate natural gas gathering pipelines in Oklahoma and Texas; (ii) approximately 2,433 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 24 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	2008 Average Daily Inlet Volumes (MMcf/d)	Inlet Capacity (MMcf/d)
Calumet (A)	1969	Lean Oil	Gas	109	250
Canute (B)	1996	Cryogenic	Electric	55	60
Cox City (B)	1994	Cryogenic	Gas/Electric	180	180
Harrah (A)	1994	Cryogenic	Gas/Electric	11	38
Thomas (A)	1981	Cryogenic	Gas	133	135
Wetumka (A)	1983	Cryogenic	Gas	51	60
Atoka (C)	2007	Refrigeration	Electric	16	20
				555	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 116,184 square feet of office space at its executive offices at 515, Suite 110, and 525 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 that 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, 2008, the Company's gross property, plant and equipment (excluding construction work in progress) additions were approximately $2.0 billion and gross retirements were approximately $271.3 million. These additions were provided by internally generated funds from operating cash flows, short-term borrowings (through a combination of bank borrowings and commercial paper), long-term borrowings and permanent financings. The additions during this three-year period amounted to approximately 26.2 percent of total property, plant and equipment at December 31, 2008.

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 15 and 16 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 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. Oral arguments were made to the Tenth Circuit on September 25, 2008. No ruling was made on the oral arguments and the court took the case under advisement. 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 the Fourth Amended Petition 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 Fourth Amended Petition of the Price I case. OG&E and Enogex Inc. were not named in this case, but two subsidiary entities of the Company were named in this 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. *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.

5. *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. In September 2008, the plaintiffs filed an application with the OCC asking the OCC to modify its order which authorizes OG&E to collect the challenged franchise fee charges. A procedural schedule and notice requirements for the matter were established by the OCC on December 4, 2008. The OCC expects to hear arguments for a motion to dismiss on March 26, 2009. OG&E believes that this case is without merit.

6. *Oxley Litigation.* OG&E has been sued by John C. Oxley D/B/A Oxley Petroleum et al. in the District Court of Haskell County, Oklahoma. This case has been pending for more than 11 years. The plaintiffs' alleged that OG&E breached the terms of contracts covering several wells by failing to purchase gas from the plaintiffs' in amounts set forth in the contracts. The plaintiffs' most recent Statement of Claim describes approximately $2.7 million in take-or-pay damages (including interest) and approximately $36 million in contract repudiation damages (including interest), subject to the limitation described below. In 2001, OG&E agreed to provide the plaintiffs with approximately $5.8 million of consideration and the parties agreed to arbitrate the dispute. Consequently, OG&E will only be liable for the amount, if any, of an arbitration award in excess of $5.8 million. OG&E expects the arbitration to occur in the first half of 2009. While the Company cannot predict the precise outcome of the arbitration, based on the information known at this time, OG&E believes that this lawsuit will not have a material adverse effect on 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 13, 2009:

Name	Age	Title
Peter B. Delaney	55	Chairman of the Board, President and Chief Executive Officer - OGE Energy Corp. and Chief Executive Officer - Enogex LLC
Danny P. Harris	53	Senior Vice President and Chief Operating Officer - OGE Energy Corp. and President - Enogex LLC
Scott Forbes	51	Controller, Chief Accounting Officer and Interim Chief Financial Officer - OGE Energy Corp.
Carla D. Brockman	49	Vice President - Administration / Corporate Secretary - OGE Energy Corp.
Robert E. Grasty	40	Vice President - Human Resources - OGE Energy Corp.
Gary D. Huneryager	58	Vice President - Internal Audits - OGE Energy Corp.
S. Craig Johnston	48	Vice President - Strategic Planning and Marketing - OGE Energy Corp.
Jesse B. Langston	46	Vice President - Utility Commercial Operations - OG&E
Jean C. Leger, Jr.	50	Vice President - Utility Operations - OG&E
Cristina F. McQuistion	44	Vice President - Process and Performance Improvement - OGE Energy Corp.
E. Keith Mitchell	46	Senior Vice President and Chief Operating Officer - Enogex LLC
Howard W. Motley	60	Vice President - Regulatory Affairs - OG&E
Reid V. Nuttall	51	Vice President - Enterprise Information and Performance - OGE Energy Corp.
Melvin H. Perkins, Jr.	60	Vice President - Power Delivery - OG&E
Paul L. Renfrow	52	Vice President - Public Affairs - OGE Energy Corp.
John Wendling, Jr.	52	Vice President - Power Supply - OG&E
Max J. Myers	34	Treasurer and Managing Director of Corporate Development and Finance - OGE Energy Corp.
Jerry A. Peace	46	Chief Risk Officer - OGE Energy Corp.
John D. Rhea	40	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, Forbes, Grasty, Huneryager, Johnston, Nutall, Renfrow, Myers, Peace and Rhea and Ms. Brockman and Ms. McQuistion 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 21, 2009.

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
	2004 – Present:	Chief Executive Officer of Enogex LLC
	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
	2004:	Executive Vice President, Finance and Strategic Planning of OGE Energy Corp.
	2004 – 2005:	President of Enogex Inc.
Danny P. Harris	2007 – Present:	Senior Vice President and Chief Operating Officer of OGE Energy Corp. and OG&E and President of Enogex LLC
	2005 – 2007:	Senior Vice President of OGE Energy Corp. and President and Chief Operating Officer of Enogex Inc.
	2004 – 2005:	Vice President and Chief Operating Officer of Enogex Inc.
Scott Forbes	2008 – Present:	Interim Chief Financial Officer of OGE Energy Corp. and OG&E
	2005 – Present:	Controller and Chief Accounting Officer of OGE Energy Corp. and OG&E
	2004 – 2005:	Chief Financial Officer of First Choice Power (retail electric provider)
	2004 – 2005:	Senior Vice President and Chief Financial Officer of Texas New Mexico Power Company (electric utility)
Carla D. Brockman	2005 – Present:	Vice President – Administration / Corporate Secretary of OGE Energy Corp. and OG&E
	2004 – 2005:	Corporate Secretary of OGE Energy Corp. and OG&E
Robert E. Grasty	2008 – Present:	Vice President – Human Resources of OGE Energy Corp. and OG&E
	2004 – 2008:	Vice President – Human Resources of TIAA-CREF (financial service company)
	2004:	Global Director – Human Resources of Pfizer (pharmaceuticals company)
Gary D. Huneryager	2005 – Present:	Vice President – Internal Audits of OGE Energy Corp. and OG&E
	2004 – 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 of Worldwide Oil & Gas Markets – Air Liquide (industrial gases company)
	2004:	Manager – Strategy & Business Optimization of ConocoPhillips (international oil company)
Jesse B. Langston	2006 – Present:	Vice President – Utility Commercial Operations of OG&E
	2005 – 2006:	Director – Utility Commercial Operations of OG&E
	2004 – 2005:	Director – Corporate Planning of OG&E
Jean C. Leger, Jr.	2008 – Present:	Vice President – Utility Operations of OG&E
	2004 – 2008:	Vice President of Operations of Enogex LLC
	2004 – 2005:	Director of Field Operations of Enogex Inc.

Name		Business Experience
E. Keith Mitchell	2007 – Present:	Senior Vice President and Chief Operating Officer – Enogex LLC
	2007:	Senior Vice President– Enogex Inc.
	2004 – 2007:	Vice President, Transportation Services of Enogex Inc.
Cristina F. McQuistion	2008 – Present:	Vice President – Process and Performance Improvement of OGE Energy Corp. and OG&E
	2007 – 2008:	Executive Vice President and General Manager Point of Sale Systems of Teleflora
	2004 – 2007:	Executive Vice President – Member Services of Teleflora (floral industry and software services to floral industry company)
Howard W. Motley	2006 – Present:	Vice President – Regulatory Affairs of OG&E
	2004 – 2006:	Director – Regulatory Affairs and Strategy of OG&E
	2004:	Director – Regulatory Strategies and Utility Resources of OG&E
Reid V. Nuttall	2006 – Present:	Vice President – Enterprise Information and Performance of OGE Energy Corp. and OG&E
	2005 – 2006:	Vice President – Enterprise Architecture of National Oilwell Varco (oil and gas equipment company)
	2004 – 2005:	Chief Information Officer, Vice President – Information Technology of Varco International (oil and gas equipment company)
Melvin H. Perkins, Jr.	2007 – Present:	Vice President – Power Delivery of OG&E
	2004 – 2007:	Vice President –Transmission of OG&E
Paul L. Renfrow	2005 – Present:	Vice President – Public Affairs of OGE Energy Corp. and OG&E
	2004 – 2005:	Director – Public Affairs of OGE Energy Corp. and OG&E
John Wendling, Jr.	2007 – Present:	Vice President – Power Supply of OG&E
	2005 – 2007:	Director, Power Plant Operations of OG&E
	2004 – 2005:	Plant Manager, Sooner Power Plant of OG&E
	2004:	Plant Manager, Horseshoe Lake/Mustang Power Plants of OG&E
Max J. Myers	2009 – Present:	Treasurer and Managing Director of Corporate Development and Finance of OGE Energy Corp. and OG&E
	2008:	Managing Director of Corporate Development and Finance of OGE Energy Corp. and OG&E
	2005 – 2008:	Manager of Corporate Development of OGE Energy Corp. and OG&E
	2004 – 2005:	Director of Corporate Finance and Development of Westar Energy, Inc. (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
	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 of El Paso Electric Company
	2005 – 2006:	Assistant General Counsel and Director of Corporate Compliance and Risk Management of El Paso Electric Company
	2004 – 2005:	Assistant General Counsel and Director of Corporate Compliance of 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.

2009	Dividend Paid	Price High	Price Low
First Quarter (through January 31)	$ 0.3550	$ 26.80	$ 23.56

2008	Dividend Paid	Price High	Price Low
First Quarter	$ 0.3475	$ 36.23	$ 29.83
Second Quarter	0.3475	34.02	30.61
Third Quarter	0.3475	34.74	29.67
Fourth Quarter	0.3475	31.41	19.56

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

The number of record holders of the Company's Common Stock at December 31, 2008, was 22,705. The book value of the Company's Common Stock at December 31, 2008, was $20.28.

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 distributions, 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 distributions paid by Enogex, on Enogex's limited liability company interests. 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. The Company's ability to receive distributions on Enogex's limited liability company interests is subject to the prior rights of existing and future holders of such limited liability company interests that may be outstanding and the covenants of Enogex's debt instruments (including its credit facility) limiting the ability of Enogex to pay distributions.

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 OG&E's 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 Securities and Exchange Commission orders), and surplus accounts is less than 20 percent of capitalization;

- may not exceed 75 percent of OG&E's 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.

OG&E's certificate of incorporation further provides that no dividend may be declared or paid on the OG&E common stock until all amounts required to be paid or set aside for any sinking fund for the redemption or purchase of OG&E cumulative preferred stock, par value $25 per share, have been paid or set aside. Currently, no shares of OG&E preferred stock are outstanding and no portion of the retained earnings of OG&E is presently restricted by these provisions.

Under Enogex's current credit facility, Enogex generally may not make distributions if an event of default exists and otherwise may make monthly and quarterly distributions in amounts not to exceed the amount by which Enogex's cash on hand exceeds its current and anticipated needs, including, without limitation, for operating expenses, debt service, acquisitions and a reasonable contingency reserve (as determined from time to time by Enogex's management in accordance with Enogex's operating agreement).

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
1/1/08 – 1/31/08	95,600	$ 33.37	N/A	N/A
2/1/08 – 2/29/08	20,900	$ 33.56	N/A	N/A
3/1/08 – 3/31/08	56,500	$ 31.69	N/A	N/A
4/1/08 – 4/30/08	53,500	$ 31.66	N/A	N/A
5/1/08 – 5/31/08	41,000	$ 32.35	N/A	N/A
6/1/08 – 6/30/08	32,300	$ 33.13	N/A	N/A
7/1/08 – 7/31/08	70,900	$ 31.79	N/A	N/A
8/1/08 – 8/31/08	43,700	$ 32.97	N/A	N/A
9/1/08 – 9/30/08	93,100	$ 32.94	N/A	N/A
10/1/08 – 10/31/08	145,500	$ 25.19	N/A	N/A
11/1/08 – 11/30/08	118,400	$ 25.05	N/A	N/A
12/1/08 – 12/31/08	102,500	$ 24.59	N/A	N/A

N/A – not applicable

Item 6. Selected Financial Data.

HISTORICAL DATA

Year ended December 31	**2008**	2007	2006 (A)	2005 (B)	2004 (B)
SELECTED FINANCIAL DATA					
(In millions, except per share data)					
Results of Operations Data:					
Operating revenues	**$ 4,070.7**	$ 3,797.6	$ 4,005.6	$ 5,911.5	$ 4,862.6
Cost of goods sold	**2,818.0**	2,634.7	2,902.5	4,942.3	3,937.7
Gross margin on revenues	**1,252.7**	1,162.9	1,103.1	969.2	924.9
Other operating expenses	**790.6**	707.6	670.4	646.8	630.4
Operating income	**462.1**	455.3	432.7	322.4	294.5
Interest income	**6.7**	2.1	6.2	3.5	4.9
Allowance for equity funds used during construction	---	---	4.1	---	0.9
Other income	**15.4**	17.4	16.3	(0.3)	10.5
Other expense	**31.6**	23.7	16.7	5.5	4.7
Interest expense	**120.0**	90.2	96.0	90.3	90.8
Income tax expense	**101.2**	116.7	120.5	68.6	73.4
Income from continuing operations	**231.4**	244.2	226.1	161.2	141.9
Income from discontinued operations, net of tax	---	---	36.0	49.8	11.6
Net income	**$ 231.4**	$ 244.2	$ 262.1	$ 211.0	$ 153.5
Basic earnings per average common share					
Income from continuing operations	**$ 2.50**	$ 2.66	$ 2.48	$ 1.79	$ 1.61
Income from discontinued operations, net of tax	---	---	0.40	0.55	0.13
Net income	**$ 2.50**	$ 2.66	$ 2.88	$ 2.34	$ 1.74
Diluted earnings per average common share					
Income from continuing operations	**$ 2.49**	$ 2.64	$ 2.45	$ 1.77	$ 1.60
Income from discontinued operations, net of tax	---	---	0.39	0.55	0.13
Net income	**$ 2.49**	$ 2.64	$ 2.84	$ 2.32	$ 1.73
Dividends declared per share	**$ 1.3975**	$ 1.3675	$ 1.3375	$ 1.33	$ 1.33

(A) 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.

(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.

Year ended December 31	**2008**	2007	2006 (A)	2005 (B)	2004 (B)
SELECTED FINANCIAL DATA					
(In millions, except per share data)					
Balance Sheet Data (at period end):					
Property, plant and equipment, net (C)	**$ 5,249.8**	$ 4,246.3	$ 3,867.5	$ 3,567.4	$ 3,581.0
Total assets (D)	**$ 6,518.5**	$ 5,237.8	$ 4,898.4	$ 4,871.4	$ 4,787.1
Long-term debt	**$ 2,161.8**	$ 1,344.6	$ 1,346.3	$ 1,350.8	$ 1,424.1
Total stockholders' equity	**$ 1,896.8**	$ 1,680.9	$ 1,603.8	$ 1,375.7	$ 1,285.6
CAPITALIZATION RATIOS (E)					
Stockholders' equity	**46.7%**	55.5%	54.3%	50.5%	46.9%
Long-term debt	**53.3%**	44.5%	45.7%	49.5%	53.1%
RATIO OF EARNINGS TO					
FIXED CHARGES (F)					
Ratio of earnings to fixed charges	**3.50**	4.65	4.28	3.37	3.23

(A) The Company adopted SFAS No. 123(R) 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.
(C) Includes net property, plant and equipment related to discontinued operations of approximately $169.3 million and $34.9 million during the years ended December 31, 2004 and 2005, respectively.
(D) Amounts for years 2004 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 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, 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. ("OGE Energy" and 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 LLC and its subsidiaries ("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 former subsidiary, OGE Energy Resources, Inc. ("OERI"). 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. Also, Enogex holds a 50 percent ownership interest in the Atoka Midstream, LLC joint venture through Enogex Atoka LLC ("Atoka"), a wholly owned subsidiary of Enogex.

Effective April 1, 2008, Enogex Inc. converted from an Oklahoma corporation to a Delaware limited liability company. Also, effective April 1, 2008, Enogex Products Corporation ("Products"), a wholly owned subsidiary of Enogex, converted from an Oklahoma corporation to an Oklahoma limited liability company.

In September 2008, OGE Energy and Energy Transfer Partners, L.P. ("ETP") entered into an agreement to form a joint venture combining Enogex's midstream business with ETP's interstate operations as well as its midstream operations in the Rocky Mountains. One of the conditions to completing the joint venture was obtaining financing that met the minimum specified terms the parties had agreed to in the joint venture agreement. Under the terms of the agreement, if OGE Energy and ETP did not complete the financing and close the joint venture by March 31, 2009, either OGE Energy or ETP could terminate the contribution agreement relating to the formation of the joint venture. Due to the significant downturn in the national economy and resulting uncertainty in the capital markets, the parties determined that obtaining the financing and completing the formation of the joint venture was not feasible and not in their best interests. Accordingly, on February 12, 2009, the parties terminated the agreement to form the joint venture.

In light of the September 28, 2008 announcement of the proposed joint venture as well as market conditions, OGE Enogex Partners, L.P., a partnership formed by the Company to further develop Enogex's natural gas midstream assets and operations, which had previously filed a registration statement with the SEC for a proposed initial public offering of its common units, has determined not to proceed with the offering contemplated by the registration statement and withdrew the registration statement on September 23, 2008.

In July 2008, OGE Energy and Electric Transmission America, a joint venture of subsidiaries of American Electric Power and MidAmerican Energy Holdings Co., formed a transmission joint venture to construct high-capacity transmission line projects in western Oklahoma. The Company will own 50 percent of the joint venture. The joint venture is intended to allow the companies to lead development of renewable wind by sharing capital costs associated with the planned transmission construction. Work on the joint venture projects is scheduled to begin in late 2009 and is targeted for completion by the end of 2013. The joint venture's initial projects will include 765 kilovolt lines from Woodward 120 miles northwest to Guymon in the Oklahoma Panhandle and from Woodward 50 miles north to the Kansas border. A Southwest Power Pool ("SPP") study estimates cost for the two projects to be approximately $500 million, of which OGE Energy's portion will be approximately $250 million. For additional information regarding this joint venture, see Note 15 of Notes to Consolidated Financial Statements.

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 natural 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, leverage unique geographic position to develop renewable energy resources for wind and transmission, 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 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;
- OGE Energy and Electric Transmission America, a joint venture of subsidiaries of American Electric Power and MidAmerican Energy Holdings Co., formed a transmission joint venture in July 2008 to construct high-capacity transmission line projects in western Oklahoma which is intended to allow the companies to lead development of renewable wind with the planned transmission construction from Woodward northwest to Guymon in the Oklahoma Panhandle and from Woodward north to the Kansas border;
- OG&E signed contracts on July 31, 2008 for approximately 101 MWs of wind turbine generators and certain related balance of plant engineering, procurement and construction services associated with a future wind project ("OU Spirit") in western Oklahoma which is expected to be in service by the end of 2009;
- OG&E purchased a 51 percent interest in the 1,230 MW natural gas-fired, combined-cycle power generation facility in Luther, Oklahoma (the "Redbud Facility") in September 2008;
- OG&E issued a request for proposal ("RFP") for wind power in December 2008 for up to 300 MWs of new capability which OG&E intends to add to its power-generation portfolio no later than the end of 2010; and
- OG&E's construction initiative from 2009 to 2014 includes approximately $2.7 billion in major projects designed to expand capacity, enhance reliability and improve environmental performance. This construction initiative also includes strengthening and expanding the electric transmission, distribution and substation systems and replacing aging infrastructure.

OG&E continues to pursue additional renewable energy and the construction of associated transmission facilities required to support this renewable expansion. In 2008, OG&E established a "Quick Start" Demand Side Management program to encourage more efficient use of electricity. OG&E also announced a "Positive Energy SmartPower" initiative (commonly referred to in the industry as "Smart Grid" technologies) that will empower customers to proactively manage their energy consumption during periods of peak demand. If these initiatives are successful, OG&E believes it may be able to defer the construction of any incremental fossil fuel generation capacity until 2020.

The increase in wind power generation and the building of the transmission lines are 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 16 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 construction of new facilities and expansion of existing facilities and its interest in the Atoka joint venture; 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 15 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 2008 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

Prior to January 1, 2008, Enogex had engaged in natural gas marketing through OERI. On January 1, 2008, Enogex distributed the stock of OERI to OGE Energy. Accordingly, in the discussions below regarding the results of Enogex, the results of OERI are only included for the years ended December 31, 2007 and 2006.

2008 compared to 2007. The Company reported net income of approximately $231.4 million, or $2.49 per diluted share, in 2008 as compared to approximately $244.2 million, or $2.64 per diluted share, in 2007. The decrease in net income of approximately $12.8 million, or $0.15 per diluted share, during 2008 as compared to 2007 was primarily due to:

- a decrease in net income at OG&E of approximately $18.7 million, or $0.21 per diluted share of the Company's common stock, in 2008 as compared to 2007 primarily due to higher operation and maintenance expense, higher depreciation and amortization expense, higher other expense and higher interest expense partially offset by a higher gross margin on revenues ("gross margin") due to increased rates from various regulatory riders implemented during 2008 and lower income tax expense;
- an increase in net income at Enogex of approximately $5.0 million, or $0.05 per diluted share of the Company's common stock, in 2008 as compared to 2007 primarily due to a higher gross margin partially offset by higher operation and maintenance expense, higher depreciation and amortization expense, lower interest income, higher other expense and higher income tax expense. Net income for Enogex in 2007 included net income of approximately $10.9 million, or $0.12 per diluted share, attributable to OERI;
- net income at OERI of approximately $4.4 million, or $0.05 per diluted share of the Company's common stock, in 2008; and
- an increase in the net loss at OGE Energy of approximately $3.4 million, or $0.03 per diluted share of the Company's common stock, in 2008 compared to 2007 primarily due to higher operation and maintenance expense related to the write-off of transaction costs incurred related to the proposed joint venture between OGE Energy and ETP that has subsequently been terminated and transaction costs associated with the formation of OGE Enogex Partners, L.P. of approximately $8.8 million, partially offset by lower interest expense due to lower advances from subsidiaries and a higher income benefit due to a higher net loss.

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 and amortization 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.

Timing Items. Enogex's net income for 2007 was approximately $86.2 million, which included a loss of approximately $2.2 million resulting from recording OERI's 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 and second quarters of 2008.

Recent Developments and Regulatory Matters

Changes in the Capital, Credit and Commodity Markets

As a result of recent volatile conditions in global capital markets, including the bankruptcy filing of Lehman Brothers Holdings, Inc. ("Lehman"), general liquidity in short-term credit markets has been constrained despite several pro-active intervention measures undertaken by the Federal Reserve, the Department of the Treasury, the United States Congress and the President of the United States. As explained in more detail below, OGE Energy and OG&E historically have maintained access to short-term liquidity through the A2/P2 commercial paper market and utilization of direct borrowings on certain committed credit agreements, although the ability to access the commercial paper market has been more limited in recent months.

The recent volatility in global capital markets has lead to a reduction in the current value of long-term investments held in OGE Energy's pension trust and post-retirement benefit plan trusts. The recent decline in asset value for the plans, if it continues for any length of time, could require additional future funding requirements.

On September 15, 2008, Lehman filed for bankruptcy protection and has not funded their portion of OGE Energy's and OG&E's revolving credit agreements. At December 31, 2008, approximately $4 million and $11 million, respectively, of OGE Energy's and OG&E's revolving credit agreements are not available as this portion was assigned to Lehman. The Company has no direct credit exposure in its short-term wholesale and commodity trading activity to Lehman or its subsidiaries.

Enogex's gathering and processing margins generally improve when NGL prices are high relative to the price of natural gas (sometimes referred to as high commodity spreads). For much of the first nine months of 2008, commodity spreads were relatively high. Recently, commodity spreads have been significantly lower. If this trend continues, Enogex's results for 2009 will be affected as its 2008 results were affected. See 2009 Outlook below. Also, prices of natural gas and NGLs have been extremely volatile, and Enogex expects this volatility to continue.

Acquisition of Redbud Power Plant

On September 29, 2008, OG&E acquired a 51 percent interest in the Redbud Facility for approximately $434.5 million. OG&E will jointly own the Redbud Facility with the Oklahoma Municipal Power Authority ("OMPA") and the Grand River Dam Authority ("GRDA"), and OG&E will act as the operations manager and perform the day-to-day operation and maintenance of the Redbud Facility. Each of the joint owners will be entitled to its respective portion of the output and will pay its pro rata share of all costs of operating and maintaining the Redbud Facility. OG&E implemented a rider at the end of September 2008 to recover the Oklahoma jurisdiction revenue requirement until new rates are implemented that include Redbud's net investment, operation and maintenance expense, depreciation expense and ad valorem taxes. For additional information regarding the acquisition of the Redbud Facility, see Note 16 of Notes to Consolidated Financial Statements.

Cancelled Red Rock Power Plant and Storm Cost Recovery Rider

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 coal-fired power plant project. 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. On June 27, 2008, OG&E filed an application requesting a Storm Cost Recovery Rider ("SCRR") for the years 2007 through 2009 to recover excess storm damage costs ($35.9 million at December 31, 2007) and, at the same time, filed a motion to consolidate for hearing the Red Rock application and the SCRR application. On July 24, 2008, a settlement agreement was signed by all the parties involved in the two cases. Under the terms of the settlement agreement, OG&E will: (i) recover approximately $7.2 million, or 50 percent, of the Oklahoma jurisdictional portion of the Red Rock power plant deferred costs through a regulatory asset, (ii) amortize the Red Rock regulatory asset over a 27-year amortization period and earn the OCC's authorized rate of return beginning with OG&E's next rate case, (iii) accrue carrying costs on the debt portion of the Red Rock regulatory asset from October 1, 2007 until the date OG&E begins to recover the regulatory asset through the base rates established in OG&E's next rate case, (iv) recover the OCC Staff and Attorney General consulting fees of approximately $0.3 million related to the Red Rock pre-approval case, in OG&E's next rate case by amortizing this over a two-year period, (v) recover approximately $33.7 million of the 2007 storm costs regulatory asset, which resulted in a write-down of approximately $1.5 million, (vi) implement the SCRR to recover OG&E's actual storm expense for the four-year period from 2006 through 2009, (vii) retain the first $3.4 million from the sale of excess sulfur dioxide ("SO2") allowances, (viii) reduce storm costs recovered through the SCRR by the proceeds from the sale of SO2 allowances above the amount retained by OG&E and (ix) earn the most recent OCC authorized return on the unrecovered storm cost balance through the SCRR. On August 22, 2008, the OCC issued an order approving the settlement agreement and the SCRR was implemented in September 2008. In June 2008, OG&E wrote down the Red Rock deferred cost and the storm costs to their net present value, which resulted in a pre-tax charge of approximately $9.0 million, which is currently included in Deferred Charges and Other Assets with an offset in Other Expense on the Company's Consolidated Financial Statements.

OG&E Arkansas Rate Case Filing

On August 29, 2008, OG&E filed with the APSC an application for an annual rate increase of approximately $26.4 million to recover, among other things, costs for investments including the Redbud Facility and improvements in its system of power lines, substations and related equipment to ensure that OG&E can reliably meet growing customer demand for electricity, and a return on equity of 12.25 percent. In January 2009, the APSC Staff recommended a $12.0 million rate increase based on a 10.5 percent return on equity. The Attorney General's consultant recommended a return on equity at the current authorized level of 10.0 percent and stated that his analysis identified at least $10.9 million in reductions to OG&E's rate increase request. A hearing is scheduled for April 7, 2009. An order from the APSC is expected in June 2009 with new rates targeted for implementation in July 2009.

OG&E 2009 Oklahoma Rate Case Filing

Beginning in October 2008, OG&E began developing a rate case filing for the Oklahoma jurisdiction. On January 20, 2009, OG&E notified the OCC that it will make its planned Oklahoma rate case filing on or about February 26, 2009. OG&E is finalizing the preparation of the rate case and expects to request an increase of between $100 million and $110 million. The case is expected to proceed through the first half of 2009. If an increase is approved by the OCC, electric rates would likely be implemented in September 2009 at the earliest.

OG&E Proposed Wind Power Project

OG&E signed contracts on July 31, 2008 for approximately 101 MWs of wind turbine generators and certain related balance of plant engineering, procurement and construction services associated with the future OU Spirit wind project in western Oklahoma. OG&E will seek regulatory recovery from the OCC and plans to have this project in-service by the end of 2009. Capital expenditures associated with this project are expected to be approximately $260 million.

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, on December 8, 2008, OG&E issued an RFP to wind developers for construction of up to 300 MWs of new capability. OG&E intends to add the new capacity to its power-generation portfolio no later than the end of 2010.

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. Since the pipeline was put in service, Enogex has completed the construction of five new gas gathering compressor stations totaling approximately 26,500 horsepower of compression, and several miles of gathering pipe, including a new 16-inch line that extends the original pipeline project an additional 20 miles to the west. Enogex is continuing to expand in the Wheeler and Hemphill counties in Texas and expects to add another 16,000 horsepower of low pressure compression to the Wheeler area by October 2009.

Southeastern Oklahoma / East Side Expansions

In February 2008, Enogex completed construction of a new 20-mile pipeline project that connects 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 75 million cubic feet per day ("MMcf/d") for customers desiring low-pressure services. The pipeline was complemented by approximately 16,000 horsepower of new gathering compression which was completed in the third quarter of 2008. Also, Enogex is planning to add approximately 16 miles of 20-inch steel pipe and 60 MMcf/d of additional treating facilities. Under the assumed operating conditions, the gathering pipe is expected to have throughput capacity of approximately 300 MMcf/d and is expected to be in service by June 2009. The capital expenditures associated with the additional pipe and treating facilities are expected to be approximately $20 million.

Enogex Additional Processing Capacity

Enogex will consider building or acquiring additional processing capacity in areas where the capacity is needed. Enogex completed construction of a new 100 MMcf/d refrigeration dew point conditioning plant in Roger Mills County of Oklahoma, which became operational in August 2008. In addition, Enogex is constructing 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 by mid-2009. Also, Enogex has placed an order for a cryogenic processing plant that is scheduled for delivery in the fourth quarter of 2009, which is expected to add another 120 MMcf/d of processing capacity to Enogex's system.

2009 Outlook

The Company's 2009 earnings guidance remains unchanged at $2.30 to $2.60 per average diluted share. The Company currently projects 2009 earnings to be towards the lower half of the range primarily due to lower commodity prices in Enogex's business. The key factors and assumptions underlying this guidance are risk-adjusted to determine the ranges described below. Therefore, the ranges by component may not add to the total. The key factors and assumptions underlying this guidance have been updated to reflect current economic conditions and other developments. Management will monitor its assumptions throughout the year and will seek to take appropriate actions to offset any adverse change in its assumptions.

(In millions, except per share data)	Dollars	Diluted EPS
OG&E	$ 177 - $ 191	$ 1.83 - $ 1.98
Enogex	$ 51 - $ 68	$ 0.53 - $ 0.70
Holding Company & OERI	$ (10) -$ (5)	$ (0.10) - $ (0.05)
Consolidated	$ 220 - $250	$ 2.30 - $ 2.60

Key factors and assumptions for 2009 include:

Consolidated

- Between 96 million and 97 million average diluted shares outstanding;
- An effective tax rate of approximately 31 percent; and
- A projected loss at the holding company of between $5 million and $10 million, or $0.05 to $0.10 per diluted share, primarily due to interest expense relating to long and short-term debt borrowings.

OG&E

- Normal weather patterns are experienced for the year;
- Gross margin on weather-adjusted, retail electric sales increases approximately one percent;
- A reasonable regulatory outcome in the Oklahoma rate case with new rates in effect before the end of the third quarter of 2009;
- Arkansas annual rate increase of approximately $12 million to $14 million implemented in mid-2009;
- Storm cost recovery rider of approximately $8 million to $10 million;
- Operating expenses of approximately $595 million to $610 million;
- Interest expense of approximately $95 million to $98 million; and
- An effective tax rate of approximately 30 percent.

OG&E has significant seasonality in its earnings. OG&E typically shows minimal earnings or slight losses in the first and fourth quarters with a majority of earnings in the third quarter due to the seasonal nature of air conditioning demand.

Enogex

- Total Enogex anticipated gross margin of approximately $335 million to $375 million consisting of:
  - Transportation and storage gross margin contribution of approximately $145 million to $155 million;
  - Gathering and processing gross margin contribution of approximately $190 million to $220 million. Key factors affecting the gathering and processing gross margin forecast are:
    - Assumed increase of ten percent in gathered volumes over 2008;
    - Assumed natural gas prices of $3.50 to $4.13 per million British thermal unit ("MMBtu") in 2009;
    - Assumed realized commodity spreads of $2.38 to $2.91 per MMBtu in 2009. The realized commodity spread takes into account that 83 percent of non-ethane processing volumes that bear price risk are hedged and the amortized cost of the hedges is included in the realized commodity spread calculation;
    - Assumed weighted average NGL prices of $0.58 to $0.79 per gallon in 2009;
- Operating expenses of approximately $215 million to $225 million;
- Interest expense of approximately $35 million to $40 million; and
- An effective tax rate of approximately 39 percent.

The foregoing would result in estimated Earnings before Interest, Taxes, Depreciation and Amortization ("EBITDA") at Enogex of between $190 million to $220 million.

Reconciliation of projected EBITDA to projected net cash provided from operating activities

(In millions)	**Twelve Months Ended December 31, 2009 (A)**
Net cash provided by operating activities	**$ 155.0**
Interest expense, net	**37.0**
Changes in operating working capital which provided (used) cash:	
Accounts receivable	**(3.8)**
Accounts payable	**3.9**
Other, including changes in noncurrent assets and liabilities	**12.9**
EBITDA	**$ 205.0**

(A) Based on midpoint of 2009 guidance.

Reconciliation of projected EBITDA to projected net income

(In millions)	**Twelve Months Ended December 31, 2009 (A)**
Net Income	**$ 59.0**
Add:	
Interest expense, net	**37.0**
Income tax expense	**38.0**
Depreciation and amortization	**71.0**
EBITDA	**$ 205.0**

(A) Based on midpoint of 2009 guidance.

For a discussion of the reasons for the use of EBITDA, as well as the limitations of EBITDA as an analytical tool, see "Enogex's Non-GAAP Financial Measures" below.

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 December 2008 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 $0.3550 per share from $0.3475 per share effective with the Company's first quarter 2009 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, 2008, 2007 and 2006 and the Company's consolidated financial position at December 31, 2008 and 2007. 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)*	**2008**	2007	2006
Operating income	**$ 462.1**	$ 455.3	$ 432.7
Net income	**$ 231.4**	$ 244.2	$ 262.1
Basic average common shares outstanding	**92.4**	91.7	91.0
Diluted average common shares outstanding	**92.8**	92.5	92.1
Basic earnings per average common share	**$ 2.50**	$ 2.66	$ 2.88
Diluted earnings per average common share	**$ 2.49**	$ 2.64	$ 2.84
Dividends declared per share	**$ 1.3975**	$ 1.3675	$ 1.3375

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)*	**2008**	2007	2006
OG&E (Electric Utility)	**$ 278.3**	$ 292.0	$ 293.9
Enogex (Natural Gas Pipeline)			
Transportation and storage	**67.8**	55.0	54.7
Gathering and processing	**117.4**	91.4	79.8
OERI (Natural Gas Marketing) (A)	**6.4**	17.1	4.3
Other Operations (B)	**(7.8)**	(0.2)	---
Consolidated operating income	**$ 462.1**	$ 455.3	$ 432.7

(A) On January 1, 2008, Enogex distributed the stock of OERI to OGE Energy, and as a result, OERI is no longer a subsidiary of Enogex.
(B) Other Operations primarily includes the operations of the holding company and 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)*	**2008**	2007	2006
Operating revenues	**$ 1,959.5**	$ 1,835.1	$ 1,745.7
Cost of goods sold	**1,114.9**	1,025.1	950.0
Gross margin on revenues	**844.6**	810.0	795.7
Other operation and maintenance	**351.6**	320.7	316.5
Depreciation and amortization	**155.0**	141.3	132.2
Taxes other than income	**59.7**	56.0	53.1
Operating income	**278.3**	292.0	293.9
Interest income	**4.4**	---	1.9
Allowance for equity funds used during construction	**---**	---	4.1
Other income	**3.6**	5.0	4.0
Other expense	**11.8**	7.2	9.7
Interest expense	**79.1**	54.9	60.1
Income tax expense	**52.4**	73.2	84.8
Net income	**$ 143.0**	$ 161.7	$ 149.3
Operating revenues by classification			
Residential	**$ 751.2**	$ 706.4	$ 698.8
Commercial	**479.0**	450.1	428.3
Industrial	**219.8**	221.4	215.7
Oilfield	**151.9**	140.9	129.3
Public authorities and street light	**190.3**	181.4	171.0
Sales for resale	**64.9**	68.8	65.4
Provision for rate refund	**(0.4)**	0.1	(0.9)
System sales revenues	**1,856.7**	1,769.1	1,707.6
Off-system sales revenues	**68.9**	35.1	2.7
Other	**33.9**	30.9	35.4
Total operating revenues	**$ 1,959.5**	$ 1,835.1	$ 1,745.7
MWH (A) sales by classification *(in millions)*			
Residential	**9.0**	8.7	8.7
Commercial	**6.5**	6.3	6.2
Industrial	**4.0**	4.2	4.4
Oilfield	**2.9**	2.8	2.7
Public authorities and street light	**3.0**	3.0	2.9
Sales for resale	**1.4**	1.4	1.5
System sales	**26.8**	26.4	26.4
Off-system sales	**1.4**	0.7	---
Total sales	**28.2**	27.1	26.4
Number of customers	**770,088**	762,234	754,840
Average cost of energy per KWH (B) - cents			
Natural gas	**8.455**	6.872	6.829
Coal	**1.153**	1.143	1.114
Total fuel	**3.337**	3.173	3.003
Total fuel and purchased power	**3.710**	3.523	3.366
Degree days (C)			
Heating - Actual	**3,394**	3,175	2,746
Heating - Normal	**3,650**	3,631	3,631
Cooling - Actual	**2,081**	2,221	2,485
Cooling - Normal	**1,912**	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.

2008 compared to 2007. OG&E's operating income decreased approximately $13.7 million in 2008 as compared to 2007 primarily due to higher operating expenses, higher depreciation and amortization expense and higher taxes other than income partially offset by a higher gross margin.

Gross Margin

Gross margin was approximately $844.6 million in 2008, as compared to approximately $810.0 million in 2007, an increase of approximately $34.6 million, or 4.3 percent. The gross margin increased primarily due to:

- new revenues from the Redbud Facility rider and the storm cost recovery rider, which increased the gross margin by approximately $21.1 million;
- new customer growth in OG&E's service territory, which increased the gross margin by approximately $8.4 million; and
- increased demand and related revenues by non-residential customers in OG&E's service territory, which increased the gross margin by approximately $5.0 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 $857.2 million in 2008 as compared to approximately $756.1 million in 2007, an increase of approximately $101.1 million, or 13.4 percent, primarily due to higher 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 2008, OG&E's fuel mix was 68 percent coal, 30 percent natural gas and two percent wind. In 2007, OG&E's fuel mix was 62 percent coal, 36 percent natural gas and two percent wind. Purchased power costs were approximately $257.0 million in 2008 as compared to approximately $268.6 million in 2007, a decrease of approximately $11.6 million, or 4.3 percent. This decrease was primarily due to lower purchases from the energy imbalance service market partially offset by capacity payments made to Redbud due to the purchase power agreement in effect prior to OG&E's purchase of the Redbud Facility.

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 fuel adjustment clauses. The 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 Expenses

Other operation and maintenance expenses were approximately $351.6 million in 2008 as compared to approximately $320.7 million in 2007, an increase of approximately $30.9 million, or 9.6 percent. The increase in other operation and maintenance expenses was primarily due to:

- an increase of approximately $9.5 million due to a correction of the over-capitalization of certain payroll, benefits, other employee related costs and overhead costs in previous years, as discussed in Note 14 of Notes to Consolidated Financial Statements;
- a decrease in capitalized work of approximately $14.0 million primarily related to costs related to the 2007 ice storm that were deferred as a regulatory asset;
- an increase of approximately $6.9 million in salaries and wages expense primarily due to hiring additional employees to support OG&E's operations as well as salary increases in 2008;
- an increase of approximately $6.6 million in contract services and approximately $1.5 million in materials and supplies primarily attributable to overhaul expenses at several of OG&E's power plants;
- an increase of approximately $5.3 million due to increased spending on vegetation management;
- an increase of approximately $2.2 million in fleet transportation charges primarily due to higher fuel and maintenance costs; and
- an increase of approximately $1.3 million in professional services expense primarily due to higher engineering consulting services during 2008 as compared to 2007.

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

- lower allocations from OGE Energy of approximately $9.0 million due to lower pension and medical costs and lower incentive compensation accruals;
- a decrease of approximately $4.0 million primarily due to overtime worked during the 2007 ice storm; and

- a decrease of approximately $3.0 million due to a lower bad debt expense.

Depreciation and amortization expense was approximately $155.0 million in 2008 as compared to approximately $141.3 million in 2007, an increase of approximately $13.7 million or 9.7 percent. The increase was primarily due to additional assets, including the Redbud Facility, being placed into service in 2008 and amortization of the Arkansas storm costs that are currently recorded as a regulatory asset (see Note 1 of Notes to the Consolidated Financial Statements).

Taxes other than income were approximately $59.7 million in 2008 as compared to approximately $56.0 million in 2007, an increase of approximately $3.7 million, or 6.6 percent, primarily due to higher ad valorem and payroll taxes.

Additional Information

Interest Income. Interest income was approximately $4.4 million in 2008. There was less than $0.1 million of interest income in 2007. The increase in interest income was primarily due to interest from customers related to the fuel under recovery balance during 2008 and interest income from short-term investments.

Other Income. Other income includes, among other things, contract work performed, non-operating rental income and miscellaneous non-operating income. Other income was approximately $3.6 million in 2008 as compared to approximately $5.0 million in 2007, a decrease of approximately $1.4 million, or 28 percent, primarily due to a lower gain on the guaranteed flat bill tariff due to warmer than normal weather with more customers participating in this plan.

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 $11.8 million in 2008 as compared to approximately $7.2 million in 2007, an increase of approximately $4.6 million or 63.9 percent. The increase in other expense was primarily due to:

- a write-down of deferred costs associated with the Red Rock power plant of approximately $7.5 million; and
- a write-down of approximately $1.5 million associated with the 2007 and 2006 storm costs related to a settlement with the OCC. See Note 16 of Notes to Consolidated Financial Statements for a discussion of these matters.

These increases in other expense were partially offset by a write-off of approximately $3.1 million associated with the Red Rock power plant for the Arkansas and the FERC jurisdictions during 2007.

Interest Expense. Interest expense was approximately $79.1 million in 2008 as compared to approximately $54.9 million in 2007, an increase of approximately $24.2 million, or 44.1 percent. The increase in interest expense was primarily due to:

- an increase of approximately $16.4 million in interest expense related to the issuances of long-term debt in January, September and December 2008;
- an increase of approximately $7.2 million due to a settlement with the Internal Revenue Service ("IRS") resulting in a reversal of interest expense in 2007; and
- an increase of approximately $2.9 million in interest expense related to interest on short-term debt primarily due to increased commercial paper borrowings and revolving credit borrowings to fund the purchase of the Redbud Facility and daily operational needs of the Company.

These increases in interest expense were partially offset by a decrease of approximately $3.1 million in interest expense associated with the interest due to customers related to the fuel over recovery balance in 2007.

Income Tax Expense. Income tax expense was approximately $52.4 million in 2008 as compared to approximately $73.2 million in 2007, a decrease of approximately $20.8 million, or 28.4 percent, primarily due to lower pre-tax income during 2008 as compared to 2007 as well as a lower overall effective income tax rate primarily due to an increase in Federal renewable energy credits and additional state income tax credits in 2008 as compared 2007.

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 operation and maintenance expenses, higher depreciation and amortization expense and higher taxes other than income 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 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.

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 SO2 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 1 of Notes to Consolidated Financial Statements for a further discussion).

Operating Expenses

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 and amortization 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 less than $0.1 million of interest income in 2007. Interest income was 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 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 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 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.

Enogex – Continuing Operations

Year Ended December 31, 2008	Transportation and Storage	Gathering and Processing	Eliminations	Total
(In millions)				
Operating revenues	$ **625.9**	$ **1,053.2**	$ **(575.9)**	$ **1,103.2**
Cost of goods sold	**479.7**	**806.4**	**(575.9)**	**710.2**
Gross margin on revenues	**146.2**	**246.8**	---	**393.0**
Other operation and maintenance	**48.2**	**87.3**	---	**135.5**
Depreciation and amortization	**17.5**	**37.1**	---	**54.6**
Impairment of assets	---	**0.4**	---	**0.4**
Taxes other than income	**12.7**	**4.6**	---	**17.3**
Operating income	$ **67.8**	$ **117.4**	$ ---	$ **185.2**

Year Ended December 31, 2007		Transportation and Storage		Gathering and Processing		Marketing		Eliminations		Total
(In millions)										
Operating revenues	$	529.1	$	799.4	$	1,541.2	$	(804.5)	$	2,065.2
Cost of goods sold		396.4		603.5		1,513.4		(801.2)		1,712.1
Gross margin on revenues		132.7		195.9		27.8		(3.3)		353.1
Other operation and maintenance		48.5		72.1		10.1		(3.3)		127.4
Depreciation and amortization		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	$	508.7	$	704.3	$	1,941.3	$	(786.5)	$	2,367.8
Cost of goods sold		383.1		536.7		1,927.1		(786.5)		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 and amortization		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

Operating Data – Continuing Operations

Year Ended December 31	**2008**	2007	2006
New well connects (includes wells behind central receipt points) (A)	**357**	374	362
New well connects (excludes wells behind central receipt points)	**203**	178	206
Gathered volumes – TBtu/d (B)	**1.16**	1.05	0.98
Incremental transportation volumes – TBtu/d	**0.41**	0.47	0.46
Total throughput volumes – TBtu/d	**1.57**	1.52	1.44
Natural gas processed – TBtu/d	**0.66**	0.57	0.54
Natural gas liquids sold (keep-whole) – million gallons	**181**	252	244
Natural gas liquids sold (purchased for resale) – million gallons	**222**	117	113
Natural gas liquids sold (percent-of-liquids) – million gallons	**23**	16	14
Total natural gas liquids sold – million gallons	**426**	385	371
Average sales price per gallon	**$ 1.255**	$ 1.048	$ 0.902
Estimated realized keep-whole spreads (C)	**$ 6.15**	$ 5.35	$ 3.99

(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.
(B) Incremental transportation volumes (reported in trillion British thermal units per day) consist of natural gas moved only on the transportation pipeline.
(C) The estimated realized keep-whole spread is an approximation of the spread between the weighted-average sales price of the retained NGL commodities and the purchase price of the replacement natural gas shrink. The spread is based on the market commodity spread less any gains or losses realized from keep-whole hedging transactions. The market commodity spread is estimated using the average of the Oil Price Information Service daily average posting at the Conway, Kansas market for the NGL and the Inside FERC monthly index posting for Panhandle Eastern Pipe Line Co., Texas, Oklahoma, for the forward month contract for natural gas prices.

2008 compared to 2007. Enogex's operating income increased approximately $21.7 million in 2008 as compared to 2007 primarily due to a higher gross margin in both the gathering and processing business and the transportation and storage business partially offset by higher operating expenses in both segments.

Gross Margin

Enogex's consolidated gross margin increased approximately $39.9 million in 2008 as compared to 2007. The increase resulted from a $50.9 million higher gross margin in the gathering and processing business and a $13.5 million higher gross margin in the transportation and storage business. Gross margin in 2007 included approximately $27.8 million attributable to OERI.

The transportation and storage business contributed approximately $146.2 million of Enogex's consolidated gross margin in 2008 as compared to approximately $132.7 million in 2007, an increase of approximately $13.5 million, or 10.2 percent. The transportation operations contributed approximately $115.8 million of Enogex's consolidated gross margin in 2008 as compared to approximately $97.8 million in 2007. The storage operations contributed approximately $30.4 million of Enogex's consolidated gross margin in 2008 as compared to approximately $34.9 million in 2007. The transportation and storage gross margin increased primarily due to:

- a decreased imbalance liability, net of fuel recoveries and natural gas length positions, associated with the transportation operations in 2008, which increased the gross margin by approximately $16.3 million;
- increased crosshaul revenues as a result of a contract change in January 2008, that transferred revenues that had previously been classified as high pressure gathering revenues in 2007 as well as increased customer production in 2008, which increased the gross margin by approximately $4.9 million;
- administrative service fees received from OERI in 2008, which increased the gross margin by approximately $3.4 million; and
- increased low pressure revenues as a result of increased volumes primarily due to several new projects which began production in 2008, which increased the gross margin by approximately $2.1 million.

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

- Enogex's transportation operations moving from an under-recovered position to an over-recovered position under its FERC-approved fuel tracker in the East Zone in 2008, which resulted in a loss compared to a gain in 2007, which decreased the gross margin by approximately $8.0 million;
- lower gross margins on realized operational storage hedges in 2008 as compared to 2007, which decreased the gross margin by approximately $2.9 million;
- lower gross margins on commodity and interruptible storage fees resulting from the loss of a contract in 2008 and decreased activity due to changes in the marketplace, which decreased the gross margin by approximately $1.2 million; and
- the removal of a liability associated with a throughput contract which was transferred to the gathering and processing segment during 2007 with no comparable item recorded in 2008, which increased the 2007 gross margin by approximately $1.2 million.

The gathering and processing business contributed approximately $246.8 million of Enogex's consolidated gross margin in 2008 as compared to approximately $195.9 million in 2007, an increase of approximately $50.9 million, or 26.0 percent. The gathering operations contributed approximately $90.9 million of Enogex's consolidated gross margin in 2008 as compared to approximately $89.4 million in 2007. The processing operations contributed approximately $155.9 million of Enogex's consolidated gross margin in 2008 as compared to approximately $106.5 million in 2007. The gathering and processing gross margin increased primarily due to:

- an increase in keep-whole margins associated with the processing operations in 2008 as compared to 2007 primarily due to higher commodity spreads throughout the majority of 2008, which increased the gross margin by approximately $18.6 million;
- increased condensate margin associated with the processing operations due to higher prices and a 15.8 percent increase in volumes in 2008 as compared to 2007, which increased the gross margin by approximately $17.1 million;
- increased percent-of-liquids gross margin associated with the processing operations due to: (i) favorable pricing for NGLs, as well as a 28.3 percent increase in volumes retained by Enogex, which increased the gross margin by approximately $10.8 million and (ii) new volumes from the Atoka joint venture processing operations which began operations in August 2007, which increased the gross margin by approximately $3.2 million;
- higher compression and dehydration fees associated with the gathering operations resulting from new projects, including Atoka, in 2007 and 2008, which increased the gross margin by approximately $7.9 million;

- sales of residue gas, condensate and additional retained NGLs associated with the processing operations of the Atoka joint venture, which began operations in August 2007, which increased the gross margin by approximately $6.8 million;
- an increase of natural gas processed under new and renegotiated fixed fee processing contracts, which increased the gross margin by approximately $4.0 million;
- increased low pressure gathering fees associated with new projects, including Atoka, which increased the gross margin by approximately $4.0 million; and
- the recognition of the liability associated with a throughput contract which was transferred from the transportation and storage segment in 2007 with no comparable item recorded 2008, which decreased the 2007 gross margin by approximately $1.9 million.

These increases in the gathering and processing business were partially offset by:

- Enogex moving from an under-recovered position to an over-recovered position in the East and West Zones in 2008, which resulted in a loss compared to the gain recognized in 2007, which decreased the gross margin approximately $7.2 million;
- an increased imbalance liability, net of fuel recoveries and natural gas length positions in 2008, which decreased the gross margin by approximately $3.9 million; and
- increased costs for electric compression primarily due to the installation of a new compressor at one of Enogex's processing plants in 2008, which decreased the gross margin by approximately $3.5 million.

Operating Expenses

The aggregate of other operation and maintenance expenses, depreciation and amortization expense, impairment of assets and taxes other than income was approximately $18.2 million higher in 2008 as compared to 2007. The variances in depreciation and amortization expense on both a consolidated basis and by segment reflects increased levels of depreciable plant in service during 2008. The $8.1 million increase in other operation and maintenance expenses on a consolidated basis was primarily due to an increase in expenses for non-capitalized system projects, an increase in salaries, wages and benefits and increased allocations for overhead costs from OGE Energy and administrative service fees from OERI in 2008 as compared to 2007.

Specifically, by segment, other operation and maintenance expenses for the transportation and storage business were approximately $0.3 million, or 0.6 percent, lower in 2008 as compared to 2007 primarily due to:

- higher internal allocations for overhead costs of approximately $3.0 million to the other Enogex segments, which decreased operation and maintenance expense for the transportation and storage segment;
- lower contract professional, technical services and materials and supplies expense of approximately $1.3 million due to lower expenses on line remediation and non-capital pipeline integrity projects in 2008; and
- lower service expenses of approximately $1.1 million charged to the transportation and storage segment in 2008 by OERI due to a portion of the service fee being allocated to the gathering and processing segment in 2008.

These increases were partially offset by higher salaries, wages and other employee benefits expense of approximately $5.1 million primarily due to higher incentive compensation and hiring additional employees to support business growth.

Other operation and maintenance expenses for the gathering and processing business were approximately $15.2 million, or 21.1 percent, higher in 2008 as compared to 2007 primarily due to:

- higher allocations for overhead and labor costs from the transportation and storage segment of approximately $6.6 million in 2008;
- higher contract professional services and materials and supplies expense of approximately $3.7 million due to an increase in non-capitalized system projects in 2008; and
- higher costs for compressor and equipment rental of approximately $1.7 million due to increased business in 2008.

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Interest Income. Enogex's consolidated interest income was approximately $2.5 million in 2008 as compared to approximately $9.2 million in 2007, a decrease of approximately $6.7 million, or 72.8 percent, primarily due to a decrease in interest earned as the balance of advances to OGE Energy decreased due to dividends and capital expenditures.

Other Expense. Enogex's consolidated other expense was approximately $7.5 million in 2008 as compared to approximately $2.3 million in 2007, an increase of approximately $5.2 million primarily due to an increase in the minority interest in the earnings of the Atoka joint venture, which began operations in August 2007.

Income Tax Expense. Enogex's consolidated income tax expense was approximately $57.3 million in 2008 as compared to approximately $53.5 million in 2007, an increase of approximately $3.8 million, or 7.1 percent, primarily due to higher pre-tax income in 2008 as compared to 2007.

Timing Items. In 2007, Enogex's consolidated net income was approximately $86.2 million, which included a loss of approximately $2.2 million resulting from recording OERI's 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 and second quarters of 2008. On January 1, 2008, Enogex distributed its shares of common stock of OERI to OGE Energy.

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 and amortization expense.

Gross Margin

Enogex's consolidated gross margin increased approximately $45.7 million in 2007 as compared to 2006. The increase resulted from a $28.3 million higher gross margin in the gathering and processing business, a $7.1 million higher gross margin in the transportation and storage business and $13.6 million higher gross margin in the marketing business.

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 operations contributed approximately $97.8 million of Enogex's consolidated gross margin in 2007. The storage operations 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 operations contributed approximately $89.4 million of Enogex's consolidated gross margin in 2007. The processing operations 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 the 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 $27.8 million of Enogex's consolidated gross margin in 2007 as compared to approximately $14.2 million in 2006, an increase of approximately $13.6 million, or 95.8 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;
- 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; and
- increased gains from origination and other marketing and trading activity in 2007, which increased the gross margin by approximately $1.3 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; and
- 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.

Operating Expenses

The aggregate of other operation and maintenance expenses, depreciation and amortization expense, impairment of assets and taxes other than income was approximately $21.0 million higher in 2007 as compared to 2006. The variances in depreciation and amortization 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:

- higher 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 $0.8 million, or 8.6 percent, higher in 2007 as compared to 2006 primarily due to 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.

Timing Items. In 2007, Enogex's consolidated net income was approximately $86.2 million, which included a loss of approximately $2.2 million resulting from recording OERI's 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 and second quarters of 2008. On January 1, 2008, Enogex distributed its shares of common stock of OERI to OGE Energy.

In 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 a loss of approximately $6.3 million resulting from recording natural gas storage inventory held by OERI at the lower of cost or market value on December 31, 2006. The offsetting gains from the sale of withdrawals from inventory were realized during the first three months 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.

OERI

Year Ended December 31*(In millions)*	**2008**	2007
Operating revenues	**$ 1,529.4**	$ 1,541.2
Cost of goods sold	**1,509.5**	1,513.4
Gross margin on revenues	**19.9**	27.8
Other operation and maintenance	**12.9**	10.1
Depreciation and amortization	**0.2**	0.2
Taxes other than income	**0.4**	0.4
Operating income	**$ 6.4**	$ 17.1

2008 compared to 2007. OERI's operating income decreased approximately $10.7 million in 2008 as compared to 2007 primarily due to a lower gross margin and higher operation and maintenance expense.

Gross Margin

Gross margin was approximately $19.9 million in 2008 as compared to approximately $27.8 million in 2007, a decrease of approximately $7.9 million, or 28.4 percent. The gross margin decreased primarily due to:

- lower realized gains associated with various transportation contracts in 2008 as compared to 2007, which decreased the gross margin by approximately $12.5 million;
- increased losses on economic hedges associated with various transportation contracts from recording these hedges at market value, which decreased the gross margin by approximately $6.8 million;
- a lower of cost or market adjustment of approximately $6.2 million for natural gas storage inventory at December 31, 2008 as compared to a lower of cost or market adjustment of approximately $3.6 million at December 31, 2007, which decreased the gross margin by approximately $2.6 million; and
- lower gains on physical sales of natural gas storage inventory activity partially offset by lower storage fees paid by OERI, which decreased the gross margin by approximately $2.5 million.

These decreases in the gross margin were partially offset by:

- gains on economic hedges of storage from recording these hedges at market value on December 31, 2008 as compared to losses from recording these hedges at market value on December 31, 2007, which increased the gross margin by approximately $12.6 million; and
- increased gains from origination and other marketing and trading activity in 2008 as compared to 2007, which increased the gross margin by approximately $3.8 million.

Operating Expenses

Other operation and maintenance expenses were approximately $12.9 million in 2008 as compared to approximately $10.1 million in 2007, an increase of approximately $2.8 million, or 27.7 percent, primarily due to a higher bad debt expense of approximately $1.5 million.

Additional Information

Income Tax Expense. Income tax expense was approximately $2.9 million in 2008 as compared to approximately $6.9 million in 2007, a decrease of approximately $4.0 million, or 58.0 percent, primarily due to lower pre-tax income in 2008 as compared to 2007.

Timing Items. In 2007, OERI's net income was approximately $10.9 million, which included a loss of approximately $2.2 million resulting from recording its 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 and second quarters of 2008.

Enogex's Non-GAAP Financial Measures

Enogex has included in this Form 10-K the non-GAAP financial measure EBITDA. Enogex defines EBITDA as net income before interest, income taxes and depreciation and amortization. EBITDA is used as a supplemental financial measure by external users of the Company's financial statements such as investors, commercial banks and others, to assess:

- the financial performance of Enogex's assets without regard to financing methods, capital structure or historical cost basis;
- Enogex's operating performance and return on capital as compared to other companies in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and capital expenditure projects and the overall rates of return on alternative investment opportunities.

The economic substance behind the use of EBITDA is to measure the ability of Enogex's assets to generate cash sufficient to pay interest costs, support indebtedness and pay dividends to OGE Energy.

Enogex provides a reconciliation of EBITDA to its most directly comparable financial measures as calculated and presented in accordance with generally accepted accounting principles ("GAAP"). The GAAP measures most directly comparable to EBITDA are net cash provided from operating activities and net income. The non-GAAP financial measure of EBITDA should not be considered as an alternative to GAAP net cash provided from operating activities and GAAP net income. EBITDA is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. EBITDA should not be considered in isolation or as a substitute for analysis of Enogex's results as reported under GAAP. Because EBITDA excludes some, but not all, items that affect net income and net cash provided from operating activities and is defined differently by different companies in Enogex's industry, Enogex's definition of EBITDA may not be comparable to similarly titled measures of other companies.

To compensate for the limitations of EBITDA as an analytical tool, Enogex believes it is important to review the comparable GAAP measures and understand the differences between the measures.

Reconciliation of EBITDA to net cash provided from operating activities

Year Ended December 31 *(In millions)*	**2008**	2007
Net cash provided from operating activities (A)	**$ 242.0**	$ 107.8
Interest expense, net	**30.2**	22.4
Changes in operating working capital which provided (used) cash:		
Accounts receivable	**(24.8)**	(0.8)
Accounts payable	**(28.5)**	(5.0)
Other, including changes in noncurrent assets and liabilities	**14.4**	83.6
EBITDA (B)	**$ 233.3**	$ 208.0

(A) Approximately $10.7 million of OERI's net cash used by operating activities is included in the net cash provided by operating activities in 2007.
(B) Approximately $17.4 million of EBITDA in 2007 was attributable to OERI.

Reconciliation of EBITDA to net income

Year Ended December 31 *(In millions)*	**2008**	2007
Net income (C)	**$ 91.2**	$ 86.2
Add:		
Interest expense, net	**30.2**	22.4
Income tax expense	**57.3**	53.5
Depreciation and amortization	**54.6**	45.9
EBITDA	**$ 233.3**	$ 208.0

(C) Approximately $10.9 million of net income in 2007 was attributable to OERI.

There are no results for OERI included in the above tables for 2008 because, as of January 1, 2008, Enogex distributed the stock of OERI to OGE Energy.

Enogex - Discontinued Operations

In May 2006, Enogex's wholly owned subsidiary, Enogex Gas Gathering LLC, 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.

The Consolidated Financial Statements of the Company have been reclassified to reflect the above sale as a discontinued operation. Accordingly, revenues, costs and expenses and cash flows from this sale 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 sale occurred prior to 2007, there are no results of operations for discontinued operations during 2007 and 2008. Results for these discontinued operations are summarized and discussed below.

Year Ended December 31 *(In millions)*	**2008**	2007	2006
Operating revenues	**$** ---	$ ---	$ 9.4
Cost of goods sold	---	---	4.9
Gross margin on revenues	---	---	4.5
Other operation and maintenance	---	---	1.0
Depreciation and amortization	---	---	0.3
Taxes other than income	---	---	0.1
Operating income	---	---	3.1
Interest income	---	---	---
Other income	---	---	56.0
Other expense	---	---	---
Interest expense	---	---	---
Income before taxes	---	---	59.1
Income tax expense	---	---	23.1
Net income	**$** ---	$ ---	$ 36.0

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.

Financial Condition

The balance of Cash and Cash Equivalents was approximately $174.4 million and $8.8 million at December 31, 2008 and 2007, respectively, an increase of approximately $165.6 million primarily due to the need for the Company to have adequate liquidity due to the volatility of the commercial paper and capital markets.

The balance of Accounts Receivable was approximately $288.1 million and $334.4 million at December 31, 2008 and 2007, respectively, a decrease of approximately $46.3 million, or 13.8 percent, primarily due to a decrease in natural gas prices and volumes at OERI partially offset by an increase in OG&E's billings to its customers and increased rates from the Redbud Facility rider and storm cost recovery rider.

The balance of Accumulated Deferred Tax Assets was approximately $14.9 million and $38.1 million at December 31, 2008 and 2007, respectively, a decrease of approximately $23.2 million, or 60.9 percent, primarily due to a change in the position of the Company's deferred hedging activities during 2008.

The balance of Property, Plant and Equipment in Service was approximately $7.7 billion and $6.8 billion at December 31, 2008 and 2007, respectively, an increase of approximately $0.9 billion, or 13.2 percent, primarily due to the purchase of the Redbud Facility as well as other projects for transmission and distribution at OG&E and various gathering and transportation projects at Enogex.

The balance of Construction Work in Process was approximately $399.0 million and $179.8 million at December 31, 2008 and 2007, respectively, an increase of approximately $219.2 million primarily due to costs associated with the OU Spirit wind project in western Oklahoma for OG&E and various transportation, gathering and processing projects at Enogex.

The balance of Regulatory Asset – SFAS No. 158 was approximately $344.7 million and $174.6 million at December 31, 2008 and 2007, respectively, an increase of approximately $170.1 million or 97.4 percent. The increase was primarily due to an increase in the pension plan, restoration of retirement income plan and postretirement benefit plan obligations due to a decrease in the fair value of plan assets in 2008.

The balance of non-current Price Risk Management Assets was approximately $22.0 million and $0.3 million at December 31, 2008 and 2007, respectively, an increase of approximately $21.7 million, primarily due to NGLs and keep-whole hedges moving from a liability to an asset due to a decrease in NGL spreads in 2008.

The balance of Other Deferred Charges was approximately $63.2 million and $85.6 million at December 31, 2008 and 2007, respectively, a decrease of approximately $22.4 million, or 26.2 percent, primarily due to write-downs of the deferred costs associated with the cancellation of the Red Rock power plant project and 2007 ice storm costs and amortization of the regulatory asset for deferred pension costs.

The balance of Accounts Payable was approximately $279.7 million and $399.3 million at December 31, 2008 and 2007, respectively, a decrease of approximately $119.6 million, or 30.0 percent, primarily due to timing of outstanding checks clearing the bank, payments made in the first quarter of 2008 for the December 2007 ice storm, a decrease in the payable for gas purchases for OG&E and a decrease in volumes purchased from third parties at OERI.

The balance of current Price Risk Management Liabilities was approximately $2.3 million and $20.6 million at December 31, 2008 and 2007, respectively, a decrease of approximately $18.3 million, or 88.8 percent, primarily due to a decrease in NGL spreads in 2008.

The balance of Other Current Liabilities was approximately $62.2 million and $38.2 million at December 31, 2008 and 2007, respectively, an increase of approximately $24.0 million, or 62.8 percent, primarily due to an accrual for a margin payment to an OERI counterparty, an increase in the weighted-average cost of inventory valuation under a certain storage agreement at OERI and an increase in the liability for the OG&E off-system sales credit to other utilities and power marketers.

The balance of Long-Term Debt was approximately $2.2 billion and $1.3 billion at December 31, 2008 and 2007, respectively, an increase of approximately $0.9 billion, or 69.2 percent, primarily due to borrowings by Enogex under its revolving credit agreement in the third quarter of 2008 and the issuance of long-term debt by OG&E in January, September and December 2008.

The balance of Accrued Benefit Obligations was approximately $350.5 million and $156.2 million at December 31, 2008 and 2007, respectively, an increase of approximately $194.3 million, primarily due to plan changes for prior service cost and net loss for the pension plan, restoration of retirement income plan and postretirement benefit plan partially offset by pension plan contributions in 2008.

The balance of Accumulated Deferred Income Taxes was approximately $996.9 million and $853.6 million at December 31, 2008 and 2007, respectively, an increase of approximately $143.3 million, or 16.8 percent, primarily due to accelerated bonus tax depreciation which resulted in higher Federal and state deferred tax accruals.

The balance of Accumulated Other Comprehensive Loss was approximately $13.7 million and $81.0 million at December 31, 2008, and 2007, respectively, a decrease of approximately $67.3 million, or 83.1 percent, primarily due to hedging gains at Enogex partially offset by plan changes for prior service cost and net loss for the pension plan, restoration of retirement income plan and postretirement benefit plan.

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 ("FIN") 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 FIN 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.

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. In April 2008, OG&E amended its contract to add 55 new railcars for approximately $3.5 million. 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 $31.5 million. See Note 15 of Notes to Consolidated Financial Statements for a further discussion.

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 expected to be primarily related to maturing debt, operating lease obligations, hedging activities, delays in recovering unconditional fuel purchase obligations, fuel clause under and over recoveries and other general corporate purposes. 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. However, OGE Energy's and OG&E's ability to access the commercial paper market was adversely impacted by the market turmoil that began in September 2008. Accordingly, in order to ensure the availability of funds, OGE Energy and OG&E utilized borrowings under their revolving credit agreements, which generally bear a higher interest rate and a minimum 30-day maturity compared to commercial paper, which has historically been available at lower interest rates and on a daily basis. However, in late 2008, OGE Energy's and OG&E's revolving credit borrowings had a lower interest rate than commercial paper due to disruptions in the credit markets. In December 2008, OG&E repaid the outstanding borrowings under its revolving credit agreement with a portion of the proceeds received from the issuance of long-term debt in December. OG&E intends to utilize commercial paper in the commercial paper market when available. OGE Energy expects to repay the borrowings under its revolving credit agreement and begin utilizing the commercial paper market when available.

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

(In millions)	Total	Less than 1 year (2009)	1 - 3 years (2010-2011)	3 - 5 years (2012-2013)	More than 5 years
OG&E capital expenditures including AFUDC (A)	$2,736.5	$ 611.5	$ 865.8	$ 825.5	$ 433.7
Enogex capital expenditures including capitalized interest	980.0	230.0	300.0	300.0	150.0
Other Operations capital expenditures	382.3	30.5	108.6	219.6	23.6
Total capital expenditures	4,098.8	872.0	1,274.4	1,345.1	607.3
Maturities of long-term debt	2,165.3	---	400.0	120.0	1,645.3
Interest payments on long-term debt	1,739.3	143.9	233.5	213.1	1,148.8
Pension funding obligations	190.0	50.0	70.0	70.0	---
Total capital requirements	8,193.4	1,065.9	1,977.9	1,748.2	3,401.4
Operating lease obligations					
OG&E railcars	45.7	3.9	41.8	---	---
Enogex noncancellable operating leases	8.7	4.2	4.1	0.4	---
Total operating lease obligations	54.4	8.1	45.9	0.4	---
Other purchase obligations and commitments					
OG&E cogeneration capacity payments	416.9	86.8	168.1	162.0	N/A
OG&E fuel minimum purchase commitments	527.3	320.7	179.3	7.8	19.5
Other	36.2	5.4	10.8	11.9	8.1
Total other purchase obligations and commitments	980.4	412.9	358.2	181.7	27.6
Total capital requirements, operating lease obligations and other purchase obligations and commitments	9,228.2	1,486.9	2,382.0	1,930.3	3,429.0
Amounts recoverable through fuel adjustment clause (B)	(989.9)	(411.4)	(389.2)	(169.8)	(19.5)
Total, net	$8,238.3	$1,075.5	$1,992.8	$1,760.5	$3,409.5

(A) Under current environmental laws and regulations, OG&E may be required to spend approximately $110 million in capital expenditures on its power plants related to regional haze projects. Until the compliance plan is approved as discussed below, the total cost of compliance, including capital expenditures, cannot be estimated by OG&E with a reasonable degree of certainty.
(B) Includes expected recoveries of costs incurred for OG&E's railcar operating lease obligations and OG&E's unconditional fuel purchase obligations.
N/A – not available

Variances in the actual cost of fuel used in electric generation (which includes the operating lease obligations for OG&E's railcar leases shown above) and certain purchased power costs, as compared to the fuel component included in the cost-of-service for ratemaking, are passed through to OG&E's customers through 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 fuel adjustment clauses and have little, if any, impact on net capital requirements and future contractual obligations. The fuel adjustment clauses are subject to periodic review by the OCC, the APSC and the FERC.

2008 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 $1,377.2 million and contractual obligations, net of recoveries through fuel adjustment clauses, were approximately $8.6 million resulting in total net capital requirements and contractual obligations of approximately $1,385.8 million in 2008. Approximately $4.4 million of the 2008 capital requirements were to comply with environmental regulations. This compares to net capital requirements of approximately $676.5 million and net contractual obligations of approximately $9.7 million totaling approximately $686.2 million in 2007, of which approximately $9.3 million was to comply with environmental regulations. During 2008, the Company's sources of capital were cash generated from operations and long-term borrowings. 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.

Issuance of Long-Term Debt

In January 2008, OG&E issued $200 million of 6.45% senior notes due February 1, 2038. The proceeds from the issuance were used to repay commercial paper borrowings.

On April 1, 2008, Enogex entered into a $250 million unsecured five-year revolving credit facility. Subject to certain limitations, the facility provides Enogex with the option, exercisable annually, to extend the maturity of the facility for an additional year and, upon the expiration of the revolving term, an option to convert the outstanding balance under the facility to a one-year term loan. The facility provides the option for Enogex to increase the borrowing limit by up to an additional $250 million (to a maximum of $500 million) upon the agreement of the lenders (or any additional lender) and the satisfaction of other specified conditions. At December 31, 2008, there was $120.0 million outstanding under the facility. These borrowings are not expected to be repaid within the next 12 months, therefore, they are classified as long-term debt for financial reporting purposes.

In September 2008, OG&E issued $250 million of 6.35% senior notes due September 1, 2018. The proceeds from the issuance were used to fund a portion of the acquisition of the Redbud Facility. Pending such use, the proceeds were used to temporarily repay a portion of OG&E's outstanding commercial paper borrowings, as well as short-term borrowings from OGE Energy, both of which were incurred in part to fund OG&E's daily operational needs.

In December 2008, OG&E issued $250 million of 8.25% senior notes due January 15, 2019. The proceeds from the issuance were used to repay borrowings under OG&E's term loan agreement with UBS AS, Stamford Branch and UBS Securities LLC, as discussed in Note 12 of Notes to Consolidated Financial Statements, and the Company's and OG&E's revolving credit agreements, which were used to fund OG&E's daily operational needs as well as OG&E's acquisition of the Redbud Facility.

Long-Term Debt Maturities

Other than the January 2010 maturity of Enogex's long-term debt discussed below, there are no maturities of the Company's long-term debt during 2010. Also, there are no maturities of the Company's long-term debt in years 2009, 2011 or 2012. Other than any outstanding balance under Enogex's revolving credit facility, which matures in 2013, there are no maturities of the Company's long-term debt during 2013. At December 31, 2008, there was $120.0 million outstanding under Enogex's revolving credit facility.

At December 31, 2008, the Company had approximately $174.4 million of cash on hand. At December 31, 2008, the Company had approximately $816.7 million of net available liquidity under its revolving credit agreements.

Cash Flows

Year Ended December 31*(In millions)*	**2008**	2007	2006
Net cash provided from operating activities	**$ 625.0**	$ 328.5	$ 569.5
Net cash used in investing activities	**(1,184.1)**	(556.3)	(483.5)
Net cash provided from (used in) financing activities	**724.7**	188.7	(137.4)

The increase of approximately $296.5 million in net cash provided from operating activities in 2008 as compared to 2007 was primarily due to: (i) a decrease in accounts payable due to payments in the first quarter of 2008 related to the December 2007 ice storm and a decrease in volumes purchased from third parties at OERI, (ii) an increase in price risk management assets and liabilities due to net cash collateral received from counterparties related to the Company's existing derivative positions, (iii) an increase in fuel clause recoveries due to higher fuel recoveries in 2008 as compared to 2007 and (iv) an increase in accounts receivable at OERI primarily due to a decrease in natural gas prices and volumes partially offset by a decrease at OG&E due to higher billed sales in 2008. The reduction of approximately $241.0 million in net cash provided from operating activities in 2007 as compared to 2006 was primarily related to lower fuel recoveries from OG&E customers partially offset by changes to other working capital.

The increase of approximately $627.8 million in net cash used in investing activities in 2008 as compared to 2007 related to higher level of capital expenditures primarily related to the purchase of the Redbud Facility and a higher level of capital expenditures at Enogex. 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 $536.0 million in net cash provided from financing activities in 2008 as compared to 2007 primarily related to proceeds received from the issuance of long-term debt in January, September and December 2008 and an increase in proceeds from the line of credit primarily related to Enogex capital expenditures and the payment of a dividend to OGE Energy. 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.

Future Capital Requirements and Financing Activities

Capital Expenditures

The Company's current 2009 to 2014 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: 2009 - $872.0 million, 2010 - $593.4 million, 2011 - $681.0 million, 2012 - $652.8 million, 2013 - $692.3 million and 2014 - $607.3 million. These capital expenditures include expenditures related to: (i) the proposed transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma, (ii) OGE Energy's portion of the proposed transmission projects as part of a newly formed transmission joint venture, (iii) OG&E's proposed 101 MW OU Spirit wind power project in western Oklahoma, (iv) OG&E's proposed system hardening plan and (v) OG&E's transmission/substation SPP project (see Note 16 of Notes to Consolidated Financial Statements for a further discussion). These capital expenditures exclude any environmental expenditures associated with Best Available Retrofit Technology ("BART") requirements. As discussed in Note 15 of Notes to Consolidated Financial Statements, due to comments from the U.S. Environmental Protection Agency ("EPA") that OG&E's proposed initial BART compliance plan would not satisfy the applicable requirements, OG&E completed additional analysis. On May 30, 2008, OG&E filed the results with the Oklahoma Department of Environmental Quality ("ODEQ") for the affected generating units. In the May 30, 2008 filing, OG&E indicated its intention to install low nitrogen oxide ("NOX") combustion technology at its affected generating stations and to continue to burn low sulfur coal at its four coal-fired generating units at its Muskogee and Sooner generating stations. The capital expenditures associated with the installation of the low NOX combustion technology are expected to be approximately $110 million. OG&E believes that these control measures will achieve visibility improvements in a cost-effective manner. OG&E did not propose the installation of scrubbers at its four coal-fired generating units because OG&E concluded that, consistent with the EPA's regulations on BART, the installation of scrubbers (at an estimated cost of $1.7 billion) would not be cost-effective. OG&E previously reported an expectation that a compliance plan would be approved by the EPA by December 31, 2008; however, submission of the overall compliance plan by the ODEQ (which will include OG&E's compliance plan previously submitted to the ODEQ) has been delayed and the current timing of the EPA approval cannot be reasonably predicted. In a letter dated November 4, 2008, the EPA notified the ODEQ that they had completed their review of BART applications for all affected sources in Oklahoma, which included OG&E. The EPA did not approve or disapprove the applications, however, additional information was requested from the ODEQ by the EPA regarding OG&E's plan. The Company cannot predict what action the EPA or the ODEQ will take in response to OG&E's May 30, 2008 filing or the November 4, 2008 letter from the EPA. Until the compliance plan is approved, the total cost of compliance, including capital expenditures, cannot be estimated by OG&E with a reasonable degree of certainty. Due to this uncertainty regarding BART costs, the Company has excluded any BART costs from its foregoing capital expenditure estimates. OG&E also has approximately 440 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.

Refinancing of Long-Term Debt

In late 2009, Enogex intends to refinance its $400.0 million medium-term notes which mature in January 2010. Due to uncertainty in the current credit markets, at this time, Enogex cannot predict how interest rates will affect its ability to obtain financing on favorable terms

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 2008, actual asset returns for the Company's defined benefit pension plan were negatively affected by the slowdown in growth in the equity markets. At December 31, 2008, approximately 45 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 2008, asset returns on the pension plan decreased approximately 25.1 percent as compared to an increase of approximately 4.4 percent in 2007. During the same time, corporate bond yields, which are used in determining the discount rate for future pension obligations, have continued to decline.

During both 2008 and 2007, the Company made contributions to its pension plan of approximately $50.0 million. 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. During 2009, the Company may contribute up to $50.0 million to its pension plan.

In accordance with Statement of Financial Accounting Standards ("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, 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 a pension settlement charge and a retirement restoration plan settlement charge in 2007. The Company did not record a pension settlement charge during 2008. The pension settlement charge 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 Charge:				
2007	$ 13.3	$ 0.5	$ 2.9	$ 16.7
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 13 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, 2008, the projected benefit obligation and fair value of assets of the Company's pension plan and restoration of retirement income plan was approximately $554.3 million and $389.9 million, respectively, for an underfunded status of approximately $164.4 million. Also, at December 31, 2008, the accumulated postretirement benefit obligation and fair value of assets of the Company's postretirement benefit plans was approximately $234.3 million and $57.0 million, respectively, for an underfunded status of approximately $177.3 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, 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.

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 alters the manner in which pension plan assets and liabilities are valued for purposes of calculating required pension contributions, 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 were 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. See Note 13 of Notes to Consolidated Financial Statements for a further discussion of changes made to the Company's plans in order to comply with the Pension Protection Act.

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 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.

Short-Term Debt

Short-term borrowings generally are used to meet working capital requirements. At December 31, 2008, the Company had approximately $298.0 million in outstanding borrowings under its revolving credit agreements and no outstanding commercial paper borrowings. At December 31, 2007, the Company had approximately $295.0 million in outstanding commercial paper borrowings and no outstanding borrowings under its revolving credit agreements. The following table shows the Company's revolving credit agreements and available cash at December 31, 2008.

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

Entity	Aggregate Commitment	Amount Outstanding	Weighted-Average Interest Rate	Maturity
OGE Energy	$ 596.0	$ 298.0	0.75%	December 6, 2012
OG&E	389.0	---	---	December 6, 2012
Enogex	250.0	120.0	1.86%	March 31, 2013
	1,235.0	418.0	1.07%	
Cash	174.4	N/A	N/A	N/A
Total	$ 1,409.4	$ 418.0	1.07%	

OGE Energy's and OG&E's ability to access the commercial paper market was adversely impacted by the market turmoil that began in September 2008. Accordingly, in order to ensure the availability of funds, OGE Energy and OG&E

utilized borrowings under their revolving credit agreements, which generally bear a higher interest rate and a minimum 30-day maturity compared to commercial paper, which has historically been available at lower interest rates and on a daily basis. However, in late 2008, OGE Energy's and OG&E's revolving credit borrowings had a lower interest rate than commercial paper due to disruptions in the credit markets. In December 2008, OG&E repaid the outstanding borrowings under its revolving credit agreement with a portion of the proceeds received from the issuance of long-term debt in December. OG&E intends to utilize commercial paper in the commercial paper market when available. OGE Energy expects to repay the borrowings under its revolving credit agreement and begin utilizing the commercial paper market when available. 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, 2009 and ending December 31, 2010. See Note 12 of Notes to the Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

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 ("ARO"), 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 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 13 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	+/- $19.5 million
Discount rate	+/- 0.25 percent	+/- $16.7 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 2008, 2007 or 2006.

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 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 15 and 16 of Notes to Consolidated Financial Statements and Item 3 in this Form 10-K.

Asset Retirement Obligations

In accordance with FIN No. 47, “Accounting for Conditional Asset Retirement Obligations,” an entity was required to recognize a liability for the fair value of an 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 2008; 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 and OG&E’s power plant 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 risk management objectives. 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 and NGL hedges. During 2008, 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 NGL hedges. Maturities of Enogex’s commodity hedging positions at December 31, 2008 occur in 2009 through 2011. OERI utilized hedge accounting to manage commodity exposure for certain transportation and natural gas inventory hedges. Maturities of OERI’s commodity hedging positions at December 31, 2008 do not extend beyond the first quarter of 2009. 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 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 2006 and 2007 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, 2008, 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 $0.3 million. At December 31, 2008 and 2007, Accrued Unbilled Revenues were approximately $47.0 million and $45.7 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, 2008, if the provision rate were to increase or decrease by ten percent, this would cause a change in the uncollectible expense recognized of approximately $0.2 million. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Consolidated Balance Sheets and is included in Other Operation and Maintenance Expense on the Consolidated Statements of Income. The allowance for uncollectible accounts receivable was approximately $2.3 million and $3.4 million at December 31, 2008 and 2007, respectively.

Natural Gas Transportation and Storage and Gathering and Processing 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.

The Company recognizes revenue from natural gas gathering, processing, transportation and storage services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold.

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.

Natural Gas Inventory

Natural gas inventory is held by Enogex through its transportation and storage business. The transportation and storage business maintains natural gas inventory to provide operational support for its pipeline deliveries. In an effort to mitigate market price exposures, Enogex enters into contracts or hedging instruments to protect the cash flows associated with its inventory. All natural gas inventory held by Enogex is recorded at the lower of cost or market. During 2008, Enogex recorded a write-down to market value related to natural gas storage inventory of approximately $0.7 million. Enogex did not record a write-down to market value related to natural gas storage inventory during 2007. The amount of Enogex's natural gas inventory was approximately $16.2 million and $37.7 million at December 31, 2008 and 2007, respectively, which included approximately $20.9 million of OERI inventory at December 31, 2007. 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 and gathering and processing segments was approximately $0.9 million and $0.4 million at December 31, 2008 and 2007, respectively.

Marketing Segment

Operating Revenues

OERI engages in energy marketing, trading and hedging activities related to the purchase and sale of natural gas as well as hedging activity related to natural gas and NGLs on behalf of Enogex. Contracts utilized in these activities generally include purchases and sales for physical delivery of natural gas, over-the-counter forward swap and option contracts and exchange traded futures and options. OERI's activities are accounted for in accordance with SFAS No. 133 and Emerging issues Task Force ("EITF") Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading Risk Management Activities." In accordance with SFAS No. 133, contracts that qualify as derivatives are reflected at fair value with the resulting unrealized gains and losses recorded as Price Risk Management Assets or Liabilities in the Consolidated Balance Sheets, classified as current or long-term based on their anticipated settlement, 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 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. 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 as Operating Revenues or Cost of Goods Sold depending on whether the contract to the sale or purchase of the commodity.

Operating revenues for physical delivery of natural gas are recorded the month of physical delivery 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. 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.

Purchase and Sale Contracts

OERI utilizes energy purchases and sales for physical delivery of natural gas and financial instruments including over-the-counter forward swap and option contracts and exchange traded futures and options. The majority of these activities qualify as derivatives pursuant to SFAS No. 133 and are recorded at fair market value in accordance with SFAS No. 157, "Fair Value Measurements." OERI portfolio is marked to estimated fair market value on a daily basis. When available, actual 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 position for which market prices are not available, models based n 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 location. Actual experience can vary significantly from these estimates and assumptions.

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, 2008, unrealized mark-to-market gains were approximately $24.9 million, which included approximately $0.2 million of unrealized mark-to-market gains that were calculated utilizing models. At December 31, 2008, 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 less than $0.1 million.

Natural Gas Inventory

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. All natural gas inventory held by OERI is recorded at the lower of cost or market. During 2008 and 2007, OERI recorded a write-down to market value related to natural gas storage inventory of approximately $6.2 million and $3.6 million, respectively. The amount of OERI's natural gas inventory was approximately $15.9 million at December 31, 2008. 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 was less than $0.1 million at December 31, 2008.

Accounting Pronouncements

See Notes 1, 2, 3, 4, 6, 9 and 13 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 for the time being, if such efforts were renewed, retail competition and the unbundling of regulated energy service could have a significant financial impact on the Company due to possible impairments 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 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 15 and 16 of Notes to Consolidated Financial Statements and Item 3 of Part I in this 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 and OERI. This committee's purpose is to develop and maintain risk policies for the unregulated entities, to provide oversight and guidance for existing and prospective unregulated business activities and to provide governance regarding compliance with unregulated 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, 2008 were as follows:

	Commodity	Notional Volume (A)	Maturity	Fair Value
	(dollars and volumes in millions)			
Trading				
Price Risk Management Assets				
Physical Purchases	Natural Gas	8.4	2009	$ 2.2
Physical Purchases	Natural Gas	0.9	2010	0.2
Total Physical Purchases				2.4
Physical Sales	Natural Gas	17.4	2009	5.1
Short Physical Options	Natural Gas	26.5	2009	0.9
Short Physical Options	Natural Gas	1.4	2010	0.1
Short Physical Options	Natural Gas	1.4	2011	0.1
Short Physical Options	Natural Gas	1.4	2012	0.1
Short Physical Options	Natural Gas	0.8	2013	0.1
Total Short Physical Options				1.3
Short Financial Swaps/Futures (fixed)	Natural Gas	0.4	2009	1.5
Long Basis Positions	Natural Gas	2.5	2009	0.4
Total Trading Price Risk Management Assets				$10.7
Non-Trading				
Long Financial Swaps/Futures (fixed)	Natural Gas	0.5	2010	$ 1.8
Short Financial Swaps/Futures (fixed)	NGL	1.4	2009	23.7
Short Financial Swaps/Futures (fixed)	NGL	1.3	2010	17.2
Total Short Financial Swaps/Futures (fixed)				40.9
Long Financial Options	NGL	1.3	2009	18.1
Long Financial Options	NGL	1.3	2010	41.0
Long Financial Options	NGL	1.3	2011	44.9
Total Long Financial Options				104.0
Total Non-Trading Price Risk Management Assets				$146.7
Total Price Risk Management Assets				$157.4
Amounts offset in Price Risk Management through Master Netting Agreements				($123.5)
Net Price Risk Management Assets				$ 33.9
Trading				
Price Risk Management Liabilities				
Physical Purchases	Natural Gas	6.0	2009	$ 0.7
Physical Sales	Natural Gas	5.9	2009	0.6
Long Financial Swaps/Futures (fixed)	Natural Gas	0.8	2009	0.6
Short Financial Swaps/Futures (fixed)	Natural Gas	0.5	2009	0.2
Long Basis Positions	Natural Gas	1.8	2009	0.4
Short Basis Positions	Natural Gas	1.0	2009	0.1
Total Trading Price Risk Management Liabilities				$ 2.6
Non-Trading				
Long Financial Swaps/Futures (fixed)	Natural Gas	9.1	2009	$ 32.3
Long Financial Swaps/Futures (fixed)	Natural Gas	10.6	2010	18.4
Long Financial Swaps/Futures (fixed)	Natural Gas	5.2	2011	17.7
Total Long Financial Swaps/Futures (fixed)				68.4
Long Basis Positions	Natural Gas	0.5	2009	0.1
Short Basis Positions	Natural Gas	1.4	2009	0.1
Short Basis Positions	Natural Gas	0.3	2010	0.1
Total Short Basis Positions				0.2
Long Financial Swaps/Futures (fixed)	NGL	0.1	2009	0.2
Total Non-Trading Price Risk Management Liabilities				$ 68.9
Total Price Risk Management Liabilities				$ 71.5
Amounts offset in Price Risk Management through Master Netting Agreements				($ 65.4)
Net Price Risk Management Liabilities				$ 6.1

(A) Natural gas in MMBtu; NGLS in barrels.

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 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.

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, 2008, 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)	2009	2010	2011	2012	2013	Thereafter	Total	12/31/08 Fair Value
Fixed-rate debt (A)								
Principal amount	$ ---	$400.0	$ ---	$ ---	$ ---	$ 1,510.0	$ 1,910.0	$ 1,857.0
Weighted-average interest rate	---	8.13%	---	---	---	6.52%	6.85%	---
Variable-rate debt (B)								
Principal amount	---	---	---	---	$ 120.0	$ 135.3	$ 255.3	$ 255.3
Weighted-average interest rate	---	---	---	---	2.97%	2.41%	2.67%	---

(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 $2.6 million annually.

Commodity Price Risk

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

Trading Activities

The trading activities of OERI 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 20 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, 2008.

(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 20 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, 2008.

(In millions)	Non-Trading
Commodity market risk, net	$6.6

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 LLC; (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 and OERI, credit risk is the risk of financial loss if counterparties fail to perform their contractual obligations. Enogex and OERI maintain 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 and OERI also monitor 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)*	**2008**	2007	2006
OPERATING REVENUES			
Electric Utility operating revenues	**$ 1,959.5**	$ 1,835.1	$ 1,745.7
Natural Gas Pipeline operating revenues	**2,111.2**	1,962.5	2,259.9
Total operating revenues	**4,070.7**	3,797.6	4,005.6
COST OF GOODS SOLD (exclusive of depreciation and amortization shown below)			
Electric Utility cost of goods sold	**1,061.2**	977.8	902.5
Natural Gas Pipeline cost of goods sold	**1,756.8**	1,656.9	2,000.0
Total cost of goods sold	**2,818.0**	2,634.7	2,902.5
Gross margin on revenues	**1,252.7**	1,162.9	1,103.1
Other operation and maintenance	**492.2**	436.8	416.6
Depreciation and amortization	**217.5**	195.3	181.4
Impairment of assets	**0.4**	0.5	0.3
Taxes other than income	**80.5**	75.0	72.1
OPERATING INCOME	**462.1**	455.3	432.7
OTHER INCOME (EXPENSE)			
Interest income	**6.7**	2.1	6.2
Allowance for equity funds used during construction	---	---	4.1
Other income	**15.4**	17.4	16.3
Other expense	**(31.6)**	(23.7)	(16.7)
Net other income (expense)	**(9.5)**	(4.2)	9.9
INTEREST EXPENSE			
Interest on long-term debt	**103.0**	87.8	87.4
Allowance for borrowed funds used during construction	**(4.0)**	(4.0)	(4.5)
Interest on short-term debt and other interest charges	**21.0**	6.4	13.1
Interest expense	**120.0**	90.2	96.0
INCOME FROM CONTINUING OPERATIONS BEFORE TAXES	**332.6**	360.9	346.6
INCOME TAX EXPENSE	**101.2**	116.7	120.5
INCOME FROM CONTINUING OPERATIONS	**231.4**	244.2	226.1
DISCONTINUED OPERATIONS (NOTE 7)			
Income from discontinued operations	---	---	59.1
Income tax expense	---	---	23.1
Income from discontinued operations	---	---	36.0
NET INCOME	**$ 231.4**	$ 244.2	$ 262.1
BASIC AVERAGE COMMON SHARES OUTSTANDING	**92.4**	91.7	91.0
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**92.8**	92.5	92.1
BASIC EARNINGS PER AVERAGE COMMON SHARE			
Income from continuing operations	**$ 2.50**	$ 2.66	$ 2.48
Income from discontinued operations, net of tax	---	---	0.40
NET INCOME	**$ 2.50**	$ 2.66	$ 2.88
DILUTED EARNINGS PER AVERAGE COMMON SHARE			
Income from continuing operations	**$ 2.49**	$ 2.64	$ 2.45
Income from discontinued operations, net of tax	---	---	0.39
NET INCOME	**$ 2.49**	$ 2.64	$ 2.84
DIVIDENDS DECLARED PER SHARE	**$ 1.3975**	$ 1.3675	$ 1.3375

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

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS

December 31 *(In millions)*	**2008**	2007
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 174.4**	$ 8.8
Accounts receivable, less reserve of $3.2 and $3.8, respectively	**288.1**	334.4
Accrued unbilled revenues	**47.0**	45.7
Fuel inventories	**88.7**	82.0
Materials and supplies, at average cost	**72.1**	63.6
Price risk management	**11.9**	7.7
Gas imbalances	**6.2**	6.7
Accumulated deferred tax assets	**14.9**	38.1
Fuel clause under recoveries	**24.0**	27.3
Prepayments	**9.0**	8.0
Other	**8.3**	7.2
Total current assets	**744.6**	629.5
OTHER PROPERTY AND INVESTMENTS, at cost	**42.2**	44.5
PROPERTY, PLANT AND EQUIPMENT		
In service	**7,722.4**	6,809.2
Construction work in progress	**399.0**	179.8
Total property, plant and equipment	**8,121.4**	6,989.0
Less accumulated depreciation	**2,871.6**	2,742.7
Net property, plant and equipment	**5,249.8**	4,246.3
DEFERRED CHARGES AND OTHER ASSETS		
Income taxes recoverable from customers, net	**14.6**	17.4
Regulatory asset – SFAS No. 158	**344.7**	174.6
Price risk management	**22.0**	0.3
McClain Plant deferred expenses	**6.2**	12.4
Unamortized loss on reacquired debt	**17.7**	18.9
Unamortized debt issuance costs	**13.5**	8.3
Other	**63.2**	85.6
Total deferred charges and other assets	**481.9**	317.5
TOTAL ASSETS	**$ 6,518.5**	$ 5,237.8

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

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS (Continued)

December 31 *(In millions)*	**2008**	2007
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 298.0**	$ 295.8
Accounts payable	**279.7**	399.3
Dividends payable	**33.2**	31.9
Customer deposits	**58.8**	55.5
Accrued taxes	**26.8**	40.0
Accrued interest	**48.7**	37.0
Accrued compensation	**45.2**	53.9
Long-term debt due within one year	**---**	1.0
Price risk management	**2.3**	20.6
Gas imbalances	**24.9**	11.1
Fuel clause over recoveries	**8.6**	4.2
Other	**62.2**	38.2
Total current liabilities	**888.4**	988.5
LONG-TERM DEBT	**2,161.8**	1,344.6
COMMITMENTS AND CONTINGENCIES (NOTE 15)		
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued benefit obligations	**350.5**	156.2
Accumulated deferred income taxes	**996.9**	853.6
Accumulated deferred investment tax credits	**17.3**	22.0
Accrued removal obligations, net	**150.9**	139.7
Price risk management	**3.8**	11.3
Other	**52.1**	41.0
Total deferred credits and other liabilities	**1,571.5**	1,223.8
STOCKHOLDERS' EQUITY		
Common stockholders' equity	**802.9**	756.2
Retained earnings	**1,107.6**	1,005.7
Accumulated other comprehensive loss, net of tax	**(13.7)**	(81.0)
Total stockholders' equity	**1,896.8**	1,680.9
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 6,518.5**	$ 5,237.8

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 *(In millions)*			**2008**		2007
STOCKHOLDERS' EQUITY					
Common stock, par value $0.01 per share; authorized 125.0 shares;					
and outstanding 93.5 and 91.8 shares, respectively		**$**	**0.9**	$	0.9
Premium on capital stock			**802.0**		755.3
Retained earnings			**1,107.6**		1,005.7
Accumulated other comprehensive loss, net of tax			**(13.7)**		(81.0)
Total stockholders' equity			**1,896.8**		1,680.9
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			**(0.5)**		(0.6)
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
6.35%	Senior Notes, Series Due September 1, 2018		**250.0**		---
8.25%	Senior Notes, Series Due January 15, 2019		**250.0**		---
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
6.45%	Senior Notes, Series Due February 1, 2038		**200.0**		---
Other Bonds - OG&E					
1.40% - 8.35%	Garfield Industrial Authority, January 1, 2025		**47.0**		47.0
1.24% - 8.14%	Muskogee Industrial Authority, January 1, 2025		**32.4**		32.4
1.35% - 7.75%	Muskogee Industrial Authority, June 1, 2027		**55.9**		56.0
Unamortized discount			**(3.9)**		(2.0)
Enogex					
7.07%	Medium-Term Notes, Series Due 2008		**---**		1.0
8.125%	Medium-Term Notes, Series Due 2010		**400.0**		400.0
0.31% - 4.67%	Enogex Revolving Credit Facility Due 2013		**120.0**		---
Unamortized swap monetization			**0.9**		1.8
Total long-term debt			**2,161.8**		1,345.6
Less long-term debt due within one year			**---**		1.0
Total long-term debt (excluding long-term debt due within one year)			**2,161.8**		1,344.6
Total Capitalization		**$**	**4,058.6**	$	3,025.5

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, 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, net of tax ($147.5 pre-tax)	---	---	---	90.4	90.4
Minimum pension liability adjustment - SFAS No. 158, net of tax ($1.1 pre-tax)	---	---	---	0.7	0.7
Deferred hedging gains, net of tax ($4.1 pre-tax)	---	---	---	2.5	2.5
Amortization of cash flow hedge, net of tax ($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 No. 158, net of tax					
Defined benefit pension plan and restoration of retirement income 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 No. 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 and restoration of retirement income 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 losses, net of tax (($100.0) pre-tax)	---	---	---	(61.3)	(61.3)
Amortization of cash flow hedge, net of tax ($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**
Comprehensive income					
Net income for 2008	---	---	**231.4**	---	**231.4**
Other comprehensive income, net of tax					
Defined benefit pension plan and restoration of retirement income plan:					
Net loss, net of tax (($42.2) pre-tax)	---	---	---	**(25.8)**	**(25.8)**
Prior service cost, net of tax ($0.5 pre-tax)	---	---	---	**0.3**	**0.3**
Defined benefit postretirement plans:					
Net loss, net of tax (($2.6) pre-tax)	---	---	---	**(1.6)**	**(1.6)**
Net transition obligation, net of tax ($0.3 pre-tax)	---	---	---	**0.2**	**0.2**
Prior service cost, net of tax ($0.3 pre-tax)	---	---	---	**0.2**	**0.2**
Deferred hedging gains, net of tax ($153.3 pre-tax)	---	---	---	**93.8**	**93.8**
Amortization of cash flow hedge, net of tax ($0.4 pre-tax)	---	---	---	**0.2**	**0.2**
Other comprehensive income	---	---	---	**67.3**	**67.3**
Comprehensive income	---	---	**231.4**	**67.3**	**298.7**
Dividends declared on common stock	---	---	**(129.5)**	---	**(129.5)**
Issuance of common stock	---	**46.7**	---	---	**46.7**
Balance at December 31, 2008	**$ 0.9**	**$ 802.0**	**$ 1,107.6**	**$ (13.7)**	**$ 1,896.8**

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOW

Year ended December 31 *(In millions)*	**2008**	2007	2006
CASH FLOWS FROM OPERATING ACTIVITIES			
Income from continuing operations	**$ 231.4**	$ 244.2	$ 226.1
Adjustments to reconcile income from continuing operations to net cash provided from operating activities			
Minority interest income	**6.1**	1.0	---
Depreciation and amortization	**217.5**	195.3	181.4
Impairment of assets	**0.4**	0.5	0.3
Deferred income taxes and investment tax credits, net	**123.4**	16.1	32.3
Allowance for equity funds used during construction	**---**	---	(4.1)
Loss (gain) on sale of assets	**0.1**	(0.1)	(1.6)
Loss on retirement and abandonment of fixed assets	**0.2**	3.8	6.0
Write-down of regulatory assets	**9.2**	---	---
Stock-based compensation expense	**4.3**	3.6	3.8
Excess tax benefit on stock-based compensation	**(1.9)**	(2.8)	(1.4)
Price risk management assets	**(25.9)**	32.0	58.2
Price risk management liabilities	**126.9**	(74.3)	(83.5)
Other assets	**5.1**	(24.8)	(73.7)
Other liabilities	**(22.9)**	(61.5)	18.1
Change in certain current assets and liabilities			
Funds on deposit	**---**	32.0	(32.0)
Accounts receivable, net	**46.3**	9.9	247.1
Accrued unbilled revenues	**(1.3)**	(6.0)	2.1
Fuel, materials and supplies inventories	**(15.2)**	(21.3)	(4.4)
Gas imbalance assets	**0.5**	(3.9)	29.2
Fuel clause under recoveries	**3.3**	(27.3)	101.1
Other current assets	**(2.2)**	5.4	9.3
Accounts payable	**(119.6)**	104.3	(215.4)
Customer deposits	**3.3**	2.1	5.6
Accrued taxes	**(9.0)**	(13.5)	(7.2)
Accrued interest	**11.7**	(7.0)	5.8
Accrued compensation	**(8.7)**	7.9	5.7
Gas imbalance liabilities	**13.8**	---	(24.9)
Fuel clause over recoveries	**4.4**	(92.1)	96.3
Other current liabilities	**23.8**	5.0	(10.7)
Net Cash Provided from Operating Activities	**625.0**	328.5	569.5
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures (less allowance for equity funds used during construction)	**(1,184.5)**	(557.7)	(486.6)
Proceeds from sale of assets	**0.8**	1.4	3.2
Capital contribution to unconsolidated affiliate	**(0.3)**	---	---
Other investing activities	**(0.1)**	---	(0.1)
Net Cash Used in Investing Activities	**(1,184.1)**	(556.3)	(483.5)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from long-term debt	**743.0**	---	217.5
Proceeds from line of credit	**145.0**	---	---
Issuance of common stock	**36.4**	8.2	14.5
Increase (decrease) in short-term debt, net	**2.2**	295.8	(250.0)
Excess tax benefit on stock-based compensation	**1.9**	2.8	1.4
Contributions from partners	**0.5**	9.7	---
Repayment of line of credit	**(25.0)**	---	---
Retirement of long-term debt	**(51.1)**	(3.1)	---
Dividends paid on common stock	**(128.2)**	(124.7)	(120.8)
Net Cash Provided From (Used in) Financing Activities	**724.7**	188.7	(137.4)
DISCONTINUED OPERATIONS			
Net cash used in operating activities	**---**	---	(19.9)
Net cash provided from investing activities	**---**	---	92.8
Net Cash Provided from Discontinued Operations	**---**	---	72.9
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**165.6**	(39.1)	21.5
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**8.8**	47.9	26.4
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 174.4**	$ 8.8	$ 47.9

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

1. Summary of Significant Accounting Policies

Organization

OGE Energy Corp. ("OGE Energy" and 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 LLC and its subsidiaries ("Enogex") is 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 former subsidiary, OGE Energy Resources, Inc. ("OERI"). 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. Also, Enogex holds a 50 percent ownership interest in the Atoka Midstream, LLC joint venture through Enogex Atoka LLC ("Atoka"), a wholly owned subsidiary of Enogex.

Effective April 1, 2008, Enogex Inc. converted from an Oklahoma corporation to a Delaware limited liability company. Also, effective April 1, 2008, Enogex Products Corporation ("Products"), a wholly owned subsidiary of Enogex, converted from an Oklahoma corporation to an Oklahoma limited liability company.

In July 2008, OGE Energy and Electric Transmission America, a joint venture of subsidiaries of American Electric Power and MidAmerican Energy Holdings Co., formed a transmission joint venture to construct high-capacity transmission line projects in western Oklahoma. The Company will own 50 percent of the joint venture. The joint venture is intended to allow the companies to lead development of renewable wind by sharing capital costs associated with the planned transmission construction. Work on the joint venture projects is scheduled to begin in late 2009 and is targeted for completion by the end of 2013.

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)*	**2008**	2007
Regulatory Assets		
Regulatory asset – SFAS No. 158	**$ 344.7**	$ 174.6
Deferred storm expenses	**32.2**	35.9
Fuel clause under recoveries	**24.0**	27.3
Unamortized loss on reacquired debt	**17.7**	18.9
Income taxes recoverable from customers, net	**14.6**	17.4
Deferred pension plan expenses	**14.6**	24.8
Red Rock deferred expenses	**7.4**	14.7
McClain Plant deferred expenses	**6.2**	12.4
Cogeneration credit rider under recovery	**1.4**	3.9
Miscellaneous	**1.5**	0.8
Total Regulatory Assets	**$ 464.3**	$ 330.7
Regulatory Liabilities		
Accrued removal obligations, net	**$ 150.9**	$ 139.7
Fuel clause over recoveries	**8.6**	4.2
Miscellaneous	**4.5**	4.3
Total Regulatory Liabilities	**$ 164.0**	$ 148.2

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 following table is a summary of the components of the SFAS No. 158 regulatory asset at December 31:

December 31 *(In millions)*	**2008**	2007
Defined benefit pension plan and restoration of retirement income plan:		
Net loss	**$ 259.8**	$ 112.3
Prior service cost	**3.5**	4.8
Defined benefit postretirement plans:		
Net loss	**70.4**	42.5
Net transition obligation	**10.2**	12.7
Prior service cost	**0.8**	2.3
Total	**$ 344.7**	$ 174.6

The following amounts in the SFAS No. 158 regulatory asset at December 31, 2008 are expected to be recognized as components of net periodic benefit cost in 2009:

(In millions)		
Defined benefit pension plan and restoration of retirement income plan:		
Net loss	$	**20.4**
Prior service cost		**1.2**
Defined benefit postretirement plans:		
Net loss		**3.6**
Net transition obligation		**2.5**
Prior service cost		**1.5**
Total	$	**29.2**

Fuel clause under recoveries are generated from under recoveries from OG&E's customers when OG&E's cost of fuel exceeds the amount billed to its customers. Fuel clause over recoveries are generated from over recoveries from OG&E's customers when the amount billed to its customers exceeds OG&E's cost of fuel. OG&E's fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result, OG&E under recovers fuel costs in periods of rising fuel prices above the baseline charge for fuel and over recovers fuel costs 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.

For a discussion of regulatory matters related to the deferred storm expenses and deferred Red Rock expenses and related reductions in the amounts previously recorded, see Note 16.

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.

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, 2008, there was approximately $14.6 million of expenses exceeding this level primarily related to pension settlement charge recorded by the Company during 2007 (see Note 13 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.

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.

As a result of the acquisition of a 77 percent interest in the 520 megawatt ("MW") natural gas-fired combined cycle NRG McClain Station (the "McClain Plant") completed on July 9, 2004, and consistent with the 2002 agreed-upon settlement of an OG&E rate case 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, 2008, the McClain Plant regulatory asset was approximately $6.2 million which is being recovered over the remaining one-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 has been updated and approved by the OCC in December of each year through December 2007 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's current cogeneration credit rider expires on December 31, 2009. The balance of the cogeneration credit rider under recovery was approximately $1.4 million and $3.9 million, respectively, at December 31, 2008 and 2007. 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.

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 ("ARO"), 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 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.

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 $3.2 million and $3.8 million at December 31, 2008 and 2007, 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 and OERI, credit risk is the risk of financial loss if counterparties fail to perform their contractual obligations. Enogex and OERI maintain 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 and OERI also monitor 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. Historically, OG&E has used the last-in, first-out ("LIFO") method of accounting for inventory removed from storage or stockpiles. Effective January 1, 2008, OG&E began using the weighted-average cost method to value inventory that is physically added to or withdrawn from storage or stockpiles in accordance with Oklahoma Senate Bill No. 609 ("SB 609") that was adopted in Oklahoma in 2007. SB 609 requires that electric utilities record fuel or natural gas removed from storage or stockpiles using the weighted-average cost method of accounting for inventory. In addition to satisfying the requirements of SB 609, management believes that the change from LIFO to weighted-average cost is also preferable because it provides for a more meaningful presentation in the financial statements taken as a whole and reduces the volatility associated with fuel price fluctuations on OG&E's customers. The majority of electric utility companies use the weighted-average cost method.

SFAS No. 154, "Accounting Changes and Error Corrections, a replacement of Accounting Principles Board ("APB") Opinion No. 20 and FASB Statement No. 3," requires that an entity report a change in accounting principle through retrospective application of the new principle to all prior periods unless it is impractical to do so. However, SFAS No. 71 requires that changes in accounting methods for regulated entities that affect allowable costs for rate-making purposes should be implemented in the same way that such an accounting change would be implemented for rate-making purposes. In accordance with an order from the OCC, OG&E's change in accounting method for inventory affected allowable costs for rate-making purposes, on a prospective basis only beginning January 1, 2008. Therefore the change in accounting was implemented prospectively for purposes of generally accepted accounting principles ("GAAP") and OG&E did not restate previously issued financial statements. Also, in accordance with the order from the OCC, on January 1, 2008, OG&E recorded an increase in Fuel Inventories of approximately $7.9 million with a corresponding offset recorded in Fuel Clause Under and Over Recoveries on the Company's Consolidated Financial Statements. OG&E began recovering costs from its customers using the weighted-average cost method for inventory on January 1, 2008.

The change in accounting for fuel inventory to the weighted-average cost method resulted in a higher fuel inventory balance of approximately $0.4 million at December 31, 2008. The change in accounting for fuel inventory to the weighted-average cost method did not impact the income statement for the year ended December 31, 2008 as OG&E's fuel costs are passed through to its customers through fuel adjustment clauses.

The amount of fuel inventory was approximately $56.6 million and $44.3 million at December 31, 2008 and 2007, respectively. The estimated replacement cost of fuel inventories was higher than the stated LIFO cost by approximately $7.4 million for 2007 based on the average cost of fuel purchased.

Enogex

Natural gas inventory is held by Enogex through its transportation and storage business. The transportation and storage business maintains natural gas inventory to provide operational support for its pipeline deliveries. In an effort to mitigate market price exposures, Enogex enters into contracts or hedging instruments to protect the cash flows associated with its inventory. All natural gas inventory held by Enogex is recorded at the lower of cost or market. During 2008, Enogex recorded a write-down to market value related to natural gas storage inventory of approximately $0.7 million. Enogex did not record a write-down to market value related to natural gas storage inventory during 2007. The amount of Enogex's natural gas inventory was approximately $16.2 million and $37.7 million at December 31, 2008 and 2007, respectively, which included approximately $20.9 million of OERI inventory at December 31, 2007. 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.

OERI

Natural gas inventory is held by OERI. 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, OERI enters into contracts or hedging instruments to protect the cash flows associated with its inventory. All natural gas inventory held by OERI is recorded at the lower of cost or market. During 2008 and 2007, OERI recorded write-downs to market value related to natural gas storage inventory of approximately $6.2 million and $3.6 million, respectively. The amount of OERI's natural gas inventory was approximately $15.9 million at December 31, 2008. 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.

The below table presents OG&E's ownership interest in the jointly-owned McClain Plant and the jointly-owned 1,230 MW natural gas-fired, combined-cycle power generation facility in Luther, Oklahoma (the "Redbud Facility"), and, as disclosed below, only OG&E's ownership interest is reflected in the property, plant and equipment and accumulated depreciation balances in this table. The owners of the remaining interests in the McClain Plant and the Redbud Facility are responsible for providing their own financing of capital expenditures. Also, only OG&E's proportionate interests of any direct expenses of the McClain Plant and the Redbud Facility such as fuel, maintenance expense and other operating expenses are included in the applicable financial statements captions in the Consolidated Statements of Income.

December 31, 2008 *(In millions)*	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
McClain Plant	77	**$ 181.0**	**$ 44.6**	**$ 136.4**
Redbud Facility	51	**$ 496.6 (A)**	**$ 63.9 (B)**	**$ 432.7**

(A) This amount includes a plant acquisition adjustment of approximately $153.7 million.

(B) This amount includes accumulated amortization of the plant acquisition adjustment of approximately $1.5 million.

December 31, 2007 *(In millions)*	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
McClain Plant	77	$ 181.0	$ 35.4	$ 145.6

Enogex

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.

Enogex owns a 50 percent membership interest in the Atoka joint venture and acts as the managing member and operator of the facilities owned by the joint venture. The Atoka joint venture 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. The below table presents 100 percent of the Atoka property, plant and equipment and accumulated depreciation balances as it is accounted for as a minority interest in the Company's consolidated financial statements.

December 31, 2008 *(In millions)*	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
Atoka processing plant	50	$ 32.4	$ 1.5	$ 30.9

December 31, 2007 *(In millions)*	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
Atoka processing plant	50	$ 18.3	$ 0.3	$ 18.0

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.

OGE Energy Consolidated

The Company's property, plant and equipment and related accumulated depreciation are divided into the following major classes at December 31, 2008 and 2007, respectively.

December 31, 2008 *(In millions)*	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
OGE Energy (holding company and OERI)			
Holding company property, plant and equipment	**$ 101.4**	**$ 68.8**	**$ 32.6**
OERI property, plant and equipment	**7.3**	**7.0**	**0.3**
OGE Energy property, plant and equipment	**108.7**	**75.8**	**32.9**
OG&E			
Distribution assets	**2,551.5**	**824.8**	**1,726.7**
Electric generation assets	**2,623.8**	**1,095.4**	**1,528.4**
Transmission assets	**846.1**	**299.8**	**546.3**
Intangible plant	**26.8**	**18.4**	**8.4**
Other property and equipment	**222.0**	**76.3**	**145.7**
OG&E property, plant and equipment	**6,270.2**	**2,314.7**	**3,955.5**
Enogex			
Transportation and storage assets	**822.0**	**208.6**	**613.4**
Gathering and processing assets	**920.5**	**272.5**	**648.0**
Enogex property, plant and equipment	**1,742.5**	**481.1**	**1,261.4**
Total property, plant and equipment	**$ 8,121.4**	**$ 2,871.6**	**$ 5,249.8**

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 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
OERI property, plant, and equipment	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

Depreciation and Amortization

OG&E

The provision for depreciation, which was approximately 2.7 percent of the average depreciable utility plant for both 2008 and 2007, 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 2009, the provision for depreciation is projected to be approximately 2.8 percent of the average depreciable utility plant. Amortization of intangibles is computed using the straight-line method. Approximately 6.3 percent of the remaining amortizable intangible plant balance at December 31, 2008 will be amortized over three years with approximately 37 percent of the remaining amortizable intangible plant balance at December 31, 2008 being amortized over their respective lives ranging from four to 25 years. Amortization of plant acquisition adjustments is provided on a straight-line basis over the estimated remaining service life on the acquired asset. Plant acquisition adjustments include approximately $153.7 million for the Redbud Facility, which will be amortized over a 27-year life and approximately $0.5 million for certain substation facilities in OG&E's service territory, which will be amortized over a 26 to 59-year period.

Enogex

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. 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.

OERI

Depreciation is computed principally on the straight-line method using estimated useful lives of three to 20 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, "Accounting for Asset Retirement Obligations," for periods subsequent to the initial measurement of an 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 ("FIN") 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. The Company did not recognize any new AROs during 2008; 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 and OG&E's power plant sites, have indefinite lives.

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 2008, 2007 or 2006.

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 3.58 percent, 5.78 percent and 7.79 percent for the years 2008, 2007 and 2006, respectively. The decrease in the AFUDC rates in 2008 was primarily due to lower interest rates on short-term borrowings.

Collection of Sales Tax

In the course of its operations, OG&E collects sales tax from its customers. OG&E records a current liability from sales taxes when it bills 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

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 ("NGL") 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 NGLs is recognized when the production is sold.

OERI

OERI engages in energy marketing, trading and hedging activities related to the purchase and sale of natural gas as well as hedging activity related to natural gas and NGLs on behalf of Enogex. Contracts utilized in these activities generally include purchases and sales for physical delivery of natural gas, over-the-counter forward swap and option contracts and exchange traded futures and options. OERI's activities are accounted for in accordance with SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," and Emerging Issues Task Force ("EITF") Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." In accordance with SFAS No. 133, contracts 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 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. 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 as Operating Revenues or Cost of Goods Sold depending on whether the contract relates to the sale or purchase of the commodity.

Operating revenues for physical delivery of natural gas are recorded the month of physical delivery 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. Estimated operating revenues are reflected in Accounts Receivable on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income.

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 fuel adjustment clauses, which are subject to periodic review by the OCC, the APSC and the FERC.

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, 2008 and 2007 are as follows:

December 31 *(In millions)*		**2008**		2007
Defined benefit pension plan and restoration of retirement income plan:				
Net loss, net of tax (($71.6) and ($29.4) pre-tax, respectively)	**$**	**(43.8)**	$	(18.0)
Prior service cost, net of tax (($0.8) and ($1.1) pre-tax, respectively)		**(0.5)**		(0.8)
Defined benefit postretirement plans:				
Net loss, net of tax (($8.6) and ($6.0) pre-tax, respectively)		**(5.3)**		(3.7)
Net transition obligation, net of tax (($0.8) and ($1.0) pre-tax, respectively)		**(0.5)**		(0.7)
Prior service cost, net of tax (($0.3) and ($0.7) pre-tax, respectively)		**(0.2)**		(0.4)
Deferred hedging gains (losses), net of tax ($62.4 and ($90.9) pre-tax, respectively)		**38.1**		(55.7)
Settlement and amortization of cash flow hedge, net of tax (($2.4) and ($2.7) pre-tax, respectively)		**(1.5)**		(1.7)
Total accumulated other comprehensive loss, net of tax	**$**	**(13.7)**	$	(81.0)

Approximately $12.8 million of the deferred hedging losses at December 31, 2008 are expected to be recognized into earnings during 2009.

Defined Benefit Pension and Restoration of Retirement Income and Postretirement Plans

The Company is required to disclose the amounts in accumulated other comprehensive loss at December 31, 2008 that are expected to be recognized as components of net periodic benefit cost in 2009 which are as follows:

(In millions)		
Defined benefit pension plan and restoration of retirement income plan:		
Net loss, net of tax ($5.5 pre-tax)	**$**	**3.4**
Prior service cost, net of tax ($0.3 pre-tax)		**0.2**
Defined benefit postretirement plans:		
Net loss, net of tax ($0.8 pre-tax)		**0.5**
Prior service cost, net of tax ($0.4 pre-tax)		**0.2**
Net transition obligation, net of tax ($0.2 pre-tax)		**0.1**
Total	**$**	**4.4**

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.

2. Accounting Pronouncements

In December 2007, the FASB issued SFAS No. 141 (Revised), "Business Combinations," which is intended to improve the relevance, representational faithfulness and comparability of the information that a reporting entity provides in its financial reports about a business combination and its effects. SFAS No. 141(R) replaces SFAS No. 141, "Business Combinations," and establishes principles and requirements for how the acquirer: (i) recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree; (ii) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase; and (iii) determines what information to disclose to enable users of the financial statements to evaluate the nature and financial effects

of the business combination. SFAS No. 141(R) applies to all transactions or other events in which an entity obtains control of one or more businesses and combinations achieved without the transfer of consideration. SFAS No. 141(R) also applies to all business entities, including mutual entities that previously used the pooling-of-interests method of accounting for some business combinations. SFAS No. 141(R) does not apply to: (i) the formation of a joint venture; (ii) the acquisition of an asset or a group of assets that does not constitute a business; (iii) a combination between entities or businesses under common control; or (iv) a combination between not-for-profit organizations or the acquisition of a for-profit business by a not-for-profit organization. SFAS No. 141(R) also amends SFAS No. 109, "Accounting for Income Taxes," to require the acquirer to recognize changes in the amount of its deferred tax benefits that are recognizable because of a business combination either in income from continuing operations in the period of the combination or directly in contributed capital, depending on the circumstances. SFAS No. 141(R) is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The provisions of SFAS No. 141(R) are to be applied prospectively to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008. The Company adopted this new standard effective January 1, 2009. In anticipation of the adoption of this new standard, the Company wrote off approximately $4.3 million in 2008 related to transaction costs incurred related to the proposed joint venture between OGE Energy and ETP that has subsequently been terminated.

In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements," which is intended to improve the relevance, comparability and transparency of the financial information that a reporting entity provides in its consolidated financial statements by establishing accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS No. 160 applies to all entities that prepare consolidated financial statements, except not-for-profit organizations. SFAS No. 160 amends Accounting Research Bulletin ("ARB") No. 51, "Consolidated Financial Statements," to establish accounting and reporting standards for the noncontrolling interest in a subsidiary and for the deconsolidation of a subsidiary. SFAS No. 160 also amends certain of ARB No. 51 consolidation procedures for consistency with the requirements of SFAS No. 141(R). SFAS No. 160 is effective for fiscal years, and interim periods within those fiscal years, beginning on or after December 15, 2008. The provisions of SFAS No. 160 are to be applied prospectively as of the beginning of the fiscal year in which it is initially adopted, except for the presentation and disclosure requirements, which are to be applied retrospectively for all periods presented. The Company adopted this new standard effective January 1, 2009. The adoption of this new standard will change the presentation of noncontrolling interests in the Company's consolidated financial statements for the Atoka joint venture.

In March 2008, the FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities," which requires enhanced disclosures about an entity's derivative and hedging activities and is intended to improve the transparency of financial reporting. SFAS No. 161 applies to all entities. SFAS No. 161 applies to all derivative instruments, including bifurcated derivative instruments and related hedging items accounted for under SFAS No. 133. SFAS No. 161 amends and expands the disclosure requirements of SFAS No. 133 with the intent to provide users of financial statements with an enhanced understanding of: (i) how and why an entity uses derivative instruments, (ii) how derivative instruments and related hedged items are accounted for under SFAS No. 133 and its related interpretations and (iii) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS No. 161 is effective for fiscal years and interim periods beginning after November 15, 2008. The Company adopted this new standard effective January 1, 2009. The adoption of this new standard will change the disclosure related to derivative and hedging activities in the Company's consolidated financial statements.

3. Fair Value Measurements

In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which defines fair value, establishes a framework for measuring fair value in GAAP and establishes a hierarchical framework for disclosing the observability of the inputs utilized in measuring assets and liabilities at fair value. 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 EITF Issue No. 02-3. SFAS No. 157 also amends SFAS No. 133 to remove the guidance similar to that nullified in EITF Issue No. 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 following table is a summary of the Company's assets and liabilities that are measured at fair value on a recurring basis in accordance with SFAS No. 157.

(In millions)		December 31, 2008		Level 1		Level 2		Level 3
Assets								
Gross derivative assets	**$**	**243.7**	$	83.9	$	38.6	$	121.2
Gas imbalance assets		**6.2**		---		6.2		---
Total	**$**	**249.9**	$	83.9	$	44.8	$	121.2
Liabilities								
Gross derivative liabilities	**$**	**141.8**	$	67.7	$	74.1	$	---
Gas imbalance liabilities (A)		**13.1**		---		13.1		---
Asset retirement obligations		**5.2**		---		---		5.2
Total	**$**	**160.1**	$	67.7	$	87.2	$	5.2

(A) Gas imbalance liabilities excludes fuel reserves for over/under retained fuel due to/from shippers of approximately $11.8 million, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

The three levels defined by the SFAS No. 157 hierarchy and examples of each are as follows:

Level 1 inputs are quoted prices in active markets for identical assets or liabilities that the reporting entity has the ability to access at the measurement date. An active market for the asset or liability is a market in which transactions for the asset or liability occur with sufficient frequency and volume to provide pricing information on an ongoing basis. An example of instruments that may be classified as Level 1 includes futures transactions for energy commodities traded on the New York Mercantile Exchange (“NYMEX”).

Level 2 inputs are inputs other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. If the asset or liability has a specified (contractual) term, a Level 2 input must be observable for substantially the full term of the asset or liability. Level 2 inputs include the following: (i) quoted prices for similar assets or liabilities in active markets; (ii) quoted prices for identical or similar assets or liabilities in markets that are not active; (iii) inputs other than quoted prices that are observable for the asset or liability; or (iv) inputs that are derived principally from or corroborated by observable market data by correlation or other means. An example of instruments that may be classified as Level 2 includes energy commodity purchase or sales transactions in a market such that the pricing is closely related to the NYMEX pricing.

Level 3 inputs are unobservable inputs for the asset or liability. Unobservable inputs shall be used to measure fair value to the extent that observable inputs are not available. Unobservable inputs shall reflect the reporting entity’s own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk). Unobservable inputs shall be developed based on the best information available in the circumstances, which might include the reporting entity’s own data. The reporting entity’s own data used to develop unobservable inputs shall be adjusted if information is reasonably available that indicates that market participants would use different assumptions. An example of instruments that may be classified as Level 3 includes energy commodity purchase or sales transactions of a longer duration or in an inactive market or the valuation of ARO’s such that there are no closely related markets in which quoted prices are available.

The Company utilizes either NYMEX published market prices, independent broker pricing data or broker/dealer valuations in determining the fair value of its derivative positions. The valuations of derivatives with pricing based on NYMEX published market prices may be considered Level 1 if they are settled through a NYMEX clearing broker account with daily margining. Over-the-counter derivatives with NYMEX based prices are considered Level 2 due to the impact of counterparty credit risk. Valuations based on independent broker pricing or broker/dealer valuations may be classified as Level 2 only to the extent they may be validated by an additional source of independent market data for an identical or closely related, active market. Otherwise, they are considered Level 3.

The impact to the fair value of derivatives due to credit risk is calculated using the probability of default based on Standard & Poor’s Ratings Services (“Standard & Poor’s”) and/or internally generated ratings. The fair value of derivative assets is adjusted for credit risk. The fair value of derivative liabilities is adjusted for credit risk only if the impact is deemed material.

The following table is a reconciliation of the Company's total derivatives fair value to the Company's Consolidated Balance Sheet at December 31, 2008.

(In millions)		**December 31, 2008**
Assets		
Gross derivative assets	$	243.7
Less: Amounts held in clearing broker accounts reflected in Other Current Assets		86.3
Less: Amounts offset under master netting agreements in accordance with FIN No. 39-1		65.4
Less: Collateral payments received from counterparties netted in accordance with FIN No. 39-1		58.1
Net Price Risk Management Assets	$	33.9
Liabilities		
Gross derivative liabilities	$	141.8
Less: Amounts held in clearing broker accounts reflected in Other Current Assets		70.3
Less: Amounts offset under master netting agreements in accordance with FIN No. 39-1		65.4
Less: Collateral payments to counterparties netted in accordance with FIN No. 39-1		---
Net Price Risk Management Liabilities	$	6.1

The following table is a summary of the Company's assets and liabilities that are measured at fair value on a recurring basis in accordance with SFAS No. 157 using significant unobservable inputs (Level 3).

(In millions)	**Year Ended December 31, 2008**
Derivative Assets	
Beginning balance	$ 1.4
Total gains or losses (realized/unrealized)	
Included in earnings	---
Included in other comprehensive income .	2.4
Purchases, sales, issuances and settlements, net (A)	82.0
Transfers in and/or out of Level 3 (B)	35.4
Ending balance	$ 121.2
The amount of total gains or losses for the periods included in earnings attributable to the change in unrealized gains or losses relating to assets held at December 31, 2008	$ ---

(A) Enogex purchased NGL options to hedge a portion of the commodity price risk associated with its keep-whole and percent-of-liquids processing arrangements for 2011 and to reset the price level of a portion of the existing hedged volumes for 2010.

(B) The transfers into Level 3 are primarily due to NGL swaps and shorter-term NGL options being re-categorized as Level 3. These transactions were previously categorized as Level 2 based on corroboration to price data from a related, active market. The correlation between the markets deteriorated during the fourth quarter of 2008, resulting in the transactions being transferred to Level 3.

(In millions)	**Year Ended December 31, 2008**
Asset Retirement Obligations	
Beginning balance	$ 4.9
Total gains or losses (realized/unrealized)	
Included in earnings	0.3
Included in other comprehensive income	---
Purchases, sales, issuances and settlements, net	---
Transfers in and/or out of Level 3	---
Ending balance	$ 5.2
The amount of total gains or losses for the periods included in earnings attributable to the change in unrealized gains or losses relating to assets held at December 31, 2008	$ ---

Gains and losses (realized and unrealized) included in earnings for the year ended December 31, 2008 attributable to the change in unrealized gains or losses relating to assets and liabilities held at December 31, 2008, if any, are reported in operating revenues.

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:

	2008		2007	
December 31 *(In millions)*	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Price Risk Management Assets				
Energy Trading Contracts	**$ 33.9**	**$ 33.9**	$ 8.0	$ 8.0
Price Risk Management Liabilities				
Energy Trading Contracts	**$ 6.1**	**$ 6.1**	$ 30.2	$ 30.2
Interest Rate Swap	---	---	1.7	1.7
Long-Term Debt				
Senior Notes	**$ 1,505.6**	**$ 1,420.8**	$ 807.4	$ 825.3
Industrial Authority Bonds	**135.3**	**135.3**	135.4	135.4
Enogex Notes	**399.1**	**436.1**	402.8	436.8
Enogex Revolving Credit Facility	**120.0**	**120.0**	---	---

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

4. Stock-Based Compensation

On January 21, 1998, the Company adopted a Stock Incentive Plan (the "1998 Plan") and in 2003, the Company adopted another Stock Incentive Plan (the "2003 Plan" that replaced the 1998 Plan). In 2008, the Company adopted, and its shareowners approved, a new Stock Incentive Plan (the "2008 Plan" and together with the 1998 Plan and the 2003 Plan, the "Plans"). The 2008 Plan replaced the 2003 Plan and no further awards will be granted under the 2003 Plan or the 1998 Plan. As under the 2003 Plan and the 1998 Plan, under the 2008 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 2,750,000 shares under the 2008 Plan.

Effective January 1, 2006, the Company adopted SFAS No. 123 (Revised), "Share-Based Payment," 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.

The Company recorded compensation expense of approximately $4.3 million pre-tax ($2.7 million after tax, or $0.03 per basic and diluted share) and approximately $3.8 million pre-tax ($2.3 million after tax, or $0.03 per basic and diluted share) in 2008 and 2007, respectively, related to the Company's share-based payments. Also, during 2008, the Company converted 166,504 performance units based on a payout ratio of 147.33 percent of the target number of performance units granted in February 2005. One-third of the performance units were settled in cash for approximately $3.0 million and two-thirds of the performance units were settled in the Company's common stock.

The Company issues new shares to satisfy stock option exercises and payouts of earned performance units. During 2008, 2007 and 2006, there were 875,434 shares, 496,565 shares and 738,426 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 $15.0 million, $8.2 million and $14.5 million in 2008, 2007 and 2006, respectively, related to exercised stock options.

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 performance units granted based on total shareholder return ("TSR") are contingently awarded and will be payable in shares of the Company's common stock subject to the condition that the number of performance units, if any, earned by the employees upon the expiration of a three-year award cycle (i.e. three-year cliff vesting period) 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 shares of the Company's common stock based on the Company's EPS growth over a three-year award cycle (i.e. three-year cliff vesting period) compared to a target set at the time of the grant by the Compensation Committee of the Company's Board of Directors. All of the Company's performance units are classified as equity under SFAS No. 123(R). 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 2008, 2007 and 2006, the Company awarded 242,503, 162,730 and 239,856 performance units, respectively, to certain employees of the Company and its subsidiaries.

Performance Units – Total Shareholder Return

The Company recorded compensation expense of approximately $3.2 million pre-tax ($2.0 million after tax), $2.3 million pre-tax ($1.4 million after tax) and $6.5 million pre-tax ($4.0 million after tax) in 2008, 2007 and 2006, 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 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. 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.

	2008	2007	2006
Expected dividend yield	3.8%	3.6%	4.9%
Expected price volatility	18.7%	15.9%	16.8%
Risk-free interest rate	2.21%	4.47%	4.66%
Expected life of units (in years)	2.84	2.95	2.85
Fair value of units granted	$ 33.62	$ 24.18	$ 22.93

A summary of the activity for the Company's performance units based on TSR at December 31, 2008 and changes during 2008 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 all made 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 12/31/07	363,148	1:1	
Granted (B)	181,892	1:1	
Converted	(124,886)	1:1	$ 3.8
Forfeited	(43,538)	1:1	
Units Outstanding at 12/31/08	376,616	1:1	$ 4.9
Units Fully Vested at 12/31/08 (C)	128,755	1:1	$ 3.8

(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 2006 and became fully vested at December 31, 2008, were certified by the Compensation Committee of the Company's Board of Directors in February 2009.

A summary of the activity for the Company's non-vested performance units based on TSR at December 31, 2008 and changes during 2008 are summarized in the following table:

	Number of Units	Weighted-Average Grant Date Fair Value
Units Non-Vested at 12/31/07	238,262	$ 23.42
Granted (D)	181,892	$ 33.62
Vested (E)	(128,755)	$ 22.93
Forfeited	(43,538)	$ 27.20
Units Non-Vested at 12/31/08 (F)	247,861	$ 30.50

(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 2006 and became fully vested at December 31, 2008, were certified by the Compensation Committee of the Company's Board of Directors in February 2009.
(F) Of the 247,861 performance units not vested at December 31, 2008, 228,862 performance units are assumed to vest at the end of the applicable vesting period.

At December 31, 2008, there was approximately $4.0 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 1.83 years.

Performance Units – Earnings Per Share

The Company recorded compensation expense of approximately $1.2 million pre-tax ($0.7 million after tax), $1.5 million pre-tax ($0.9 million after tax) and $2.0 million pre-tax ($1.2 million after tax) in 2008, 2007 and 2006, 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 2006, 2007 and 2008 performance units was $28.00, $33.59 and $29.22, respectively.

A summary of the activity for the Company's performance units based on EPS at December 31, 2008 and changes during 2008 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 all made 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 12/31/07	120,982	1:1	
Granted (B)	60,611	1:1	
Converted	(41,618)	1:1	$ 2.3
Forfeited	(14,511)	1:1	
Units Outstanding at 12/31/08	125,464	1:1	$ 2.2
Units Fully Vested at 12/31/08 (C)	42,914	1:1	$ 2.2

(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 2006 and became fully vested at December 31, 2008, were certified by the Compensation Committee of the Company's Board of Directors in February 2009.

A summary of the activity for the Company's non-vested performance units based on EPS at December 31, 2008 and changes during 2008 are summarized in the following table:

	Number of Units	Weighted-Average Grant Date Fair Value
Units Non-Vested at 12/31/07	79,364	$ 30.21
Granted (D)	60,611	$ 29.22
Vested (E)	(42,914)	$ 28.00
Forfeited	(14,511)	$ 30.01
Units Non-Vested at 12/31/08 (F)	82,550	$ 30.66

(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 2006 and became fully vested at December 31, 2008, were certified by the Compensation Committee of the Company's Board of Directors in February 2009.
(F) Of the 82,550 performance units not vested at December 31, 2008, 76,274 performance units are assumed to vest at the end of the applicable vesting period.

At December 31, 2008, there was approximately $1.0 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 2.0 years.

Stock Options

The Company recorded no compensation expense in 2008 or 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.

A summary of the activity for the Company's options at December 31, 2008 and changes during 2008 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 12/31/07	1,138,917	$ 21.34		
Exercised	(713,670)	$ 20.96	$ 8.5	
Options Outstanding at 12/31/08	425,247	$ 21.98	$ 1.6	4.04 years
Options Fully Vested and Exercisable at 12/31/08	425,247	$ 21.98	$ 1.6	4.04 years

Restricted Stock

Under the Plans and in the third quarter of 2008, the Company issued restricted stock to certain existing non-officer employees as well as other executives upon hire to attract and retain individuals to be competitive in the marketplace. The restricted stock vests in one-third annual increments. Prior to vesting, each share of restricted stock is subject to forfeiture if the recipient ceases to render substantial services to the Company or a subsidiary for any reason other than death, disability or retirement. These shares may not be sold, assigned, transferred or pledged and are subject to a risk of forfeiture. During 2008, the Company awarded 56,798 shares of restricted stock.

The Company recorded compensation expense of approximately $0.3 million pre-tax ($0.2 million after tax) in 2008 related to the restricted stock. The fair value of the restricted stock was based on the closing market price of the Company's common stock on the grant date. Compensation expense for the restricted stock is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over a three-year vesting period. Also, the Company treats its restricted stock as multiple separate awards by recording compensation expense separately for each tranche whereby a substantial portion of the expense is recognized in the earlier years in the requisite service period. Dividends are accrued and paid during the vesting period and, therefore, are included in the fair value calculation. The expected life of the restricted stock 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 restricted stock. The weighted-average grant date fair value of the 2008 restricted stock was $30.84.

At December 31, 2008, there was approximately $1.5 million in unrecognized compensation cost related to non-vested restricted stock which is expected to be recognized over a weighted-average period of 2.74 years.

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 2008 and 2007, 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 Company recorded less than $0.1 million for hedge ineffectiveness of commodity cash flow hedges in 2008. 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 NGLs produced by its subsidiary, Products; (iii) electric power contracts by OG&E; and (iv) fuel procurement by OG&E.

During 2008, Enogex utilized non-trading price risk management instruments to manage commodity exposure for contractual length and operational storage natural gas, keep-whole natural gas and NGL hedges. Enogex's commodity hedging activity as of December 31, 2008 covers a three-year period from 2009 through 2011. OERI utilized non-trading price risk management instrument to manage commodity exposure for certain transportation and natural gas inventory hedges. OERI's commodity hedging activity as of December 31, 2008 does not extend beyond the first quarter of 2009.

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.

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, 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 accordance with FIN No. 39 (As Amended), "Offsetting of Amounts Related to Certain Contracts – an interpretation of APB Opinion No. 10 and FASB Statement No. 105," 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 Sheets. 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 $51.8 million and $35.4 million, respectively, at December 31, 2008, and non-current Price Risk Management assets and liabilities would be approximately $105.6 million and $36.2 million, respectively, at December 31, 2008. 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.

7. Enogex – Discontinued Operations

In May 2006, Enogex's wholly owned subsidiary, Enogex Gas Gathering LLC, sold certain gas gathering assets in the Kinta, Oklahoma area, 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.

The Consolidated Financial Statements of the Company have been reclassified to reflect the above sale as a discontinued operation. Accordingly, revenues, costs and expenses and cash flows from this sale 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 sale occurred prior to 2007, there are no results of operations for discontinued operations during 2007 or 2008. Summarized financial information for the discontinued operations as of December 31 is as follows:

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Year ended December 31 *(In millions)*	**2008**	2007	2006
Operating revenues from discontinued operations from discontinued operations	**$ ---**	$ ---	$ 9.4
Income from discontinued operations before taxes	---	---	59.1

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)*	**2008**	2007	2006
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Power plant long-term service agreement	**$ 3.5**	$ 0.7	$ ---
Capital lease for distribution equipment	**0.3**	---	---
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash Paid During the Period for			
Interest (net of interest capitalized of $7.6, $4.9, $5.4)	**$122.3**	$ 93.5	$ 85.5
Income taxes (net of income tax refunds)	---	86.6	122.7

9. Income Taxes

The items comprising income tax expense are as follows:

Year ended December 31 *(In millions)*	**2008**	2007	2006
Provision (Benefit) for Current Income Taxes from Continuing Operations			
Federal	**$ (18.6)**	$ 96.0	$ 96.0
State	**(0.8)**	3.9	(7.4)
Total Provision (Benefit) for Current Income Taxes from Continuing Operations	**(19.4)**	99.9	88.6
Provision for Deferred Income Taxes, net from Continuing Operations			
Federal	**126.9**	18.2	35.4
State	**1.2**	2.7	1.9
Total Provision for Deferred Income Taxes, net from Continuing Operations	**128.1**	20.9	37.3
Deferred Federal Investment Tax Credits, net	**(4.6)**	(4.8)	(5.0)
Income Taxes Relating to Other Income and Deductions	**(2.9)**	0.7	(0.4)
Total Income Tax Expense from Continuing Operations	**$ 101.2**	$ 116.7	$ 120.5

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 2005. In September 2008, the Internal Revenue Service (“IRS”) completed its audit of tax years 2005 and 2006. Income taxes are generally allocated to each company in the affiliated group based on its stand-alone 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. In addition, OG&E earns both Federal and Oklahoma state tax credits associated with the production from its 120 MW wind farm in northwestern Oklahoma ("Centennial") wind farm that further reduce the Company's effective tax rate. The following schedule reconciles the statutory Federal tax rate to the effective income tax rate:

Year ended December 31	**2008**	2007	2006
Statutory Federal tax rate	**35.0%**	35.0%	35.0%
Amortization of net unfunded deferred taxes	**0.7**	0.8	0.7
State income taxes, net of Federal income tax benefit	**0.2**	1.9	2.8
Medicare Part D subsidy	**(0.3)**	(0.3)	(0.7)
401(k) dividends	**(0.8)**	(1.2)	(0.9)
Federal investment tax credits, net	**(1.4)**	(1.3)	(1.4)
Federal renewable energy credit (A)	**(2.7)**	(2.0)	---
Other	**(0.3)**	(0.6)	(0.7)
Effective income tax rate as reported	**30.4%**	32.3%	34.8%

(A) These are credits OG&E began earning associated with the production from the Centennial wind farm that was placed in service during January 2007.

The Company adopted the provisions of FIN 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. 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 as discussed below. A reconciliation of the beginning and ending amounts of unrecognized tax benefits is as follows:

December 31*(In millions)*	**2008**	2007
Beginning Balance	**$ ---**	$ 66.4
Settlements with tax authorities	---	(66.4)
Ending Balance	**$ ---**	$ ---

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 $0.3 million in 2006 and $2.6 million in 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 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, 2008 and 2007, respectively, were as follows:

December 31 *(In millions)*	**2008**	2007
Current Accumulated Deferred Tax Assets		
Federal renewable energy credit	**$ 9.2**	$ ---
Accrued vacation	**7.2**	6.4
Accrued liabilities	**5.6**	6.3
Uncollectible accounts	**1.5**	1.6
Derivative instruments	---	19.3
Other	---	4.5
Total Current Accumulated Deferred Tax Assets	**23.5**	38.1
Current Accumulated Deferred Tax Liabilities		
Derivative instruments	**(7.0)**	---
Other	**(1.6)**	---
Total Current Accumulated Deferred Tax Liabilities	**(8.6)**	---
Current Accumulated Deferred Tax Assets, net	**$ 14.9**	$ 38.1
Non-Current Accumulated Deferred Tax Liabilities		
Accelerated depreciation and other property related differences	**$ 1,025.7**	$ 889.0
Company pension plan	**52.1**	60.6
Derivative instruments	**17.0**	---
Income taxes refundable to customers, net	**5.7**	6.7
Bond redemption-unamortized costs	**5.7**	6.1
Regulatory asset	**3.2**	7.7
Total Non-Current Accumulated Deferred Tax Liabilities	**1,109.4**	970.1
Non-Current Accumulated Deferred Tax Assets		
Regulatory liabilities	**(58.5)**	(54.7)
Postretirement medical and life insurance benefits	**(34.3)**	(34.3)
State tax credit carryforward	**(11.8)**	---
Deferred Federal investment tax credits	**(6.7)**	(8.5)
Derivative instruments	---	(18.9)
Other	**(1.2)**	(0.1)
Total Non-Current Accumulated Deferred Tax Assets	**(112.5)**	(116.5)
Non-Current Accumulated Deferred Income Tax Liabilities, net	**$ 996.9**	$ 853.6

The Company currently estimates a Federal tax operating loss for 2008 of approximately $32.0 million primarily caused by the accelerated tax depreciation provisions contained within the Economic Stimulus Act of 2008 ("Stimulus Act"). The Stimulus Act allows a current deduction for 50 percent of the cost of certain property placed into service during 2008. This loss results in an approximately $11.2 current income tax receivable related to the 2008 tax year. It is the Company's intent to carry this tax loss back to a prior period in order to obtain cash refunds. As noted above, the impact of deferred tax accounting will not cause this refund to impact the effective tax rate.

The Company has an Oklahoma investment tax credit carryover from 2007 of approximately $7.2 million. During 2008, additional Oklahoma tax credits of approximately $16.5 million were generated or purchased by the Company. The Company currently believes that approximately $5.6 million of these state tax credit amounts will be utilized in the 2008 tax year and approximately $18.1 million will be carried over to the 2009 tax year and later years. The Company's credits do not have an expiration date.

10. Common Equity

Automatic Dividend Reinvestment and Stock Purchase Plan

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"). Beginning in the third quarter of 2008, the Company began issuing authorized, but unissued shares of common stock to satisfy the common stock requirements of the DRIP/DSPP. During 2008, there were 262,193 shares of common stock issued to satisfy the common stock requirements of the DRIP/DSPP.

In November 2008, the Company filed a Form S-3 Registration Statement to register 5,000,000 shares of the Company's common stock pursuant to the Company's DRIP/DSPP and replace the July registration statement.

At December 31, 2008, there were 11,214,461 shares of unissued common stock reserved for issuance under various employee and Company stock plans.

Equity Issuances

On November 20, 2008, OGE Energy entered into a Distribution Agreement (the "Agreement") with J.P. Morgan Securities Inc. ("JPMS"). Under the terms of the Agreement, OGE Energy could offer and sell up to 2,500,000 shares of its common stock from time to time through JPMS as principal or agent. Sales of the Company's common stock, if any, could be made by means of ordinary brokers' transactions on the New York Stock Exchange at market prices and in such other manner as agreed upon by OGE Energy and JPMS. JPMS received from OGE Energy a commission of 1.5 percent based on the gross sales price for any shares sold to or through it as principal or agent under the Agreement. Since inception of the Agreement on November 20, 2008 through December 31, 2008, the Company has sold 548,657 shares of its common stock under the Agreement. The Company has received net proceeds from JPMS of approximately $13.7 million during this timeframe (after the JPMS commission of approximately $0.2 million) related to the sale of the Company's common stock. From January 1, 2009 through January 28, 2009, the Company has sold 1,086,100 shares of its common stock under the Agreement. The Company has received net proceeds from JPMS of approximately $26.9 million during this timeframe (after the JPMS commission of approximately $0.4 million) related to the sale of the shares of the Company's common stock. The Company has added the net proceeds from the sale of the shares of its common stock to its general funds and used those proceeds for general corporate purposes, including the repayment of outstanding revolving credit borrowings or other short-term debt. On January 28, 2009, the Company provided written notice to JPMS of the Company's intent to terminate the Agreement pursuant to the terms of the Agreement, which termination was effective on January 29, 2009.

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.

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

Year ended December 31 *(In millions)*	**2008**	2007	2006
Average Common Shares Outstanding			
Basic average common shares outstanding	**92.4**	91.7	91.0
Effect of dilutive securities:			
Employee stock options and unvested stock grants	**0.1**	0.3	0.3
Contingently issuable shares (performance units)	**0.3**	0.5	0.8
Diluted average common shares outstanding	**92.8**	92.5	92.1
Anti-dilutive shares excluded from EPS calculation	---	---	0.1

11. Long-Term Debt

A summary of the Company's long-term debt is included in the Consolidated Statements of Capitalization. At December 31, 2008, the Company was in compliance with all of its debt agreements**.**

Optional Redemption of Long-Term Debt

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

SERIES	DATE DUE	AMOUNT
1.40% - 8.35%(A)	Garfield Industrial Authority, January 1, 2025	**$ 47.0**
1.24% - 8.14%(A)	Muskogee Industrial Authority, January 1, 2025	**32.4**
1.35% - 7.75%(A)	Muskogee Industrial Authority, June 1, 2027	**55.9**
Total (redeemable during next 12 months)		**$ 135.3**

(A) During the first six months of 2008, the interest rates for the Bonds were between 1.24% and 3.45%. In September 2008, the interest rates for the Bonds significantly increased to a one-week high of 8.35%. Currently, the interest rates for the Bonds are between 0.55% and 0.95%.

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 except as discussed below. If the remarketing agent is unable to remarket any such Bonds, OG&E is obligated to repurchase such unremarketed Bonds. OG&E believes that it has sufficient long-term liquidity to meet these obligations.

In September 2008, OG&E received a request for repayment of approximately $0.1 million of principal related to a portion of OG&E’s Muskogee Industrial Authority variable-rate bonds, due June 1, 2027. In September 2008, approximately $0.1 million of principal and accrued interest were paid to the bondholder. The $0.1 million of variable-rate industrial authority bonds is being remarketed by the remarketing agent.

Long-Term Debt Maturities

Other than the January 2010 maturity of Enogex’s long-term debt discussed below, there are no maturities of the Company’s long-term debt during 2010. Also, there are no maturities of the Company’s long-term debt in years 2009, 2011 or 2012. Other than any outstanding balance under Enogex’s revolving credit facility (discussed below), which matures in 2013, there are no maturities of the Company’s long-term debt during 2013. At December 31, 2008, there was $120.0 million outstanding under Enogex’s revolving credit facility.

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 Long-Term Debt

In January 2008, OG&E issued $200 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.

On April 1, 2008, Enogex entered into a $250 million unsecured five-yearrevolving credit facility. Subject to certain limitations, the facility provides Enogex with the option, exercisable annually, to extend the maturity of the facility for an additional year and, upon the expiration of the revolving term, an option to convert the outstanding balance under the facility to a one-year term loan. The facility provides the option for Enogex to increase the borrowing limit by up to an additional $250 million (to a maximum of $500 million) upon the agreement of the lenders (or any additional lender) and the satisfaction of other specified conditions. At December 31, 2008, there was $120.0 million outstanding under the facility. These borrowings are not expected to be repaid within the next 12 months, therefore, they are classified as long-term debt for financial reporting purposes.

In September 2008, OG&E issued $250 million of 6.35% senior notes due September 1, 2018. The proceeds from the issuance were used to fund a portion of the acquisition of the Redbud Facility. Pending such use, the proceeds were used to temporarily repay a portion of OG&E's outstanding commercial paper borrowings, as well as short-term borrowings from OGE Energy, both of which were incurred in part to fund OG&E's daily operational needs.

In December 2008, OG&E issued $250 million of 8.25% senior notes due January 15, 2019. The proceeds from the issuance were used to repay borrowings under OG&E's term loan agreement with UBS AS, Stamford Branch and UBS Securities LLC, as discussed in Note 12, and the Company's and OG&E's revolving credit agreements, which were used to fund OG&E's daily operational needs as well as OG&E's acquisition of the Redbud Facility.

Refinancing of Long-Term Debt

In late 2009, Enogex intends to refinance its $400.0 million medium-term notes which mature in January 2010. Due to uncertainty in the current credit markets, at this time, Enogex cannot predict how interest rates will affect its ability to obtain financing on favorable terms

12. 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 $298.0 million and $295.8 million at December 31, 2008 and 2007, respectively, at a weighted-average interest rate of 0.75 percent and 5.54 percent, respectively. The following table shows the Company's revolving credit agreements and available cash at December 31, 2008.

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

Entity	Aggregate Commitment (A)	Amount Outstanding (B)	Weighted-Average Interest Rate	Maturity
OGE Energy (C)	$ 596.0	$ 298.0	0.75% (F)	December 6, 2012 (E)
OG&E (D)	389.0	---	---% (F)	December 6, 2012 (E)
Enogex (G)	250.0	120.0	1.86%	March 31, 2013 (G)
	1,235.0	418.0	1.07%	
Cash	174.4	N/A	N/A	N/A
Total	$ 1,409.4	$ 418.0	1.07%	

(A) All of the lenders that participate in OGE Energy's, OG&E's and Enogex's revolving credit agreements have funded their commitment, with the exception of Lehman Brothers Holdings, Inc. ("Lehman"), which filed for bankruptcy protection on September 15, 2008 and has not funded their portion of the revolving credit agreements. At December 31, 2008, approximately $4 million and $11 million, respectively, of OGE Energy's and OG&E's revolving credit agreements are not available as this portion was assigned to Lehman.

(B) Includes direct borrowings, outstanding commercial paper and letters of credit at December 31, 2008.

(C) This bank facility is available to back up OGE Energy'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, 2008, there was approximately $298.0 million in outstanding borrowings under this revolving credit agreement. There were no outstanding commercial paper borrowings at December 31, 2008.

(D) This bank facility is available to back up OG&E'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, 2008, there were no outstanding borrowings under this revolving credit agreement and approximately $0.3 million supporting letters of credit. There were no outstanding commercial paper borrowings at December 31, 2008.

(E) In December 2006, OGE Energy and OG&E amended and restated their revolving credit agreements to total in the aggregate $1.0 billion, $600 million for OGE Energy 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 upon agreement of all banks participating in the revolving credit agreements. In November 2007, OGE Energy 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 maturity to convert the outstanding balance to a one-year term loan.

(F) Represents the weighted-average interest rate for the outstanding borrowings under the revolving credit agreements.

(G) On April 1, 2008, Enogex entered into a $250 million unsecured five-year revolving credit facility. Subject to certain limitations, the facility provides Enogex with the option, exercisable annually, to extend the maturity of the facility for an additional year and, upon the expiration of the revolving term, an option to convert the outstanding balance under the facility to a one-year term loan. The facility provides the option for Enogex to increase the borrowing limit by up to an additional $250 million (to a maximum of $500 million) upon the agreement of the lenders (or any additional lender) and the satisfaction of other specified conditions. This bank facility is available to provide revolving credit borrowings. At December 31, 2008, Enogex had approximately $120.0 million outstanding under this facility. These borrowings are not expected to be repaid within the next 12 months, therefore, they are classified as long-term debt for financial reporting purposes.

OGE Energy's and OG&E's ability to access the commercial paper market has been adversely impacted by the market turmoil since September 2008. Accordingly, in order to ensure the availability of funds, OGE Energy and OG&E utilized borrowings under their revolving credit agreements, which generally bear a higher interest rate and a minimum 30-day maturity compared to commercial paper, which has historically been available at lower interest rates and on a daily basis. However, in late 2008, OGE Energy's and OG&E's revolving credit borrowings had a lower interest rate than commercial paper due to disruptions in the credit markets. OG&E also borrowed under the term loan agreements discussed below. In December 2008, OG&E repaid the outstanding borrowings under its revolving credit agreement with a portion of the proceeds received from the issuance of long-term debt in December. OG&E intends to utilize commercial paper in the commercial paper market when available. OGE Energy expects to repay the borrowings under its revolving credit agreement and begin utilizing the commercial paper market when available.

In addition to general market conditions, OGE Energy's and OG&E's ability to access the commercial paper market could also be adversely impacted by a credit ratings downgrade. 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 ratings of OGE Energy or OG&E 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 additional guarantees to support some of OERI's marketing operations.

The Company had a commercial paper arrangement with Lehman, which filed for bankruptcy protection on September 15, 2008. On September 22, 2008, Barclays Plc purchased the investment banking and capital markets operations of Lehman and replaced Lehman as the commercial paper dealer in the Company's commercial paper arrangement. Also, the Company has a commercial paper arrangement with Wachovia Bank, National Association, which merged with Wells Fargo & Company on December 31, 2008.

On September 26, 2008, OG&E entered into a 10-day $300 million term loan agreement with Royal Bank of Scotland PLC ("RBS"). On September 29, 2008, after OG&E purchased the entire partnership interest in the Redbud Facility, the Oklahoma Municipal Power Authority ("OMPA") and the Grand River Dam Authority ("GRDA") purchased their respective undivided interests in the Redbud Facility from OG&E for approximately $417.5 million. After the closing of the sale of the undivided interests in the Redbud Facility, OG&E used the $417.5 million in proceeds and repaid in full, on September 30, 2008, the $300 million borrowed from RBS and invested the remainder of the proceeds in short-term investments which were recorded as Cash and Cash Equivalents on the Company's Consolidated Balance Sheet.

On September 26, 2008, OG&E entered into a $200 million term loan agreement with UBS AS, Stamford Branch and UBS Securities LLC maturing March 26, 2010. This loan could be used for general corporate purposes and permitted acquisitions as defined in the loan agreement. On December 15, 2008, OG&E repaid the outstanding $50.0 million balance and terminated this loan agreement.

Unlike OGE Energy 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, 2009 and ending December 31, 2010.

Omnibus Agreement

Concurrent with the entry of the Enogex LLC credit facility on April 1, 2008, Enogex also entered into an omnibus agreement with OGE Energy. The omnibus agreement memorializes Enogex's obligation to reimburse OGE Energy for costs incurred on behalf of Enogex and its subsidiaries. Specifically, Enogex reimburses OGE Energy, subject to a maximum reimbursement, for: (i) the performance of general and administrative services for Enogex and its subsidiaries, such as legal, accounting, treasury, finance, investor relations, insurance administration and claims processing, risk management, health, safety and environmental, information technology, human resources, credit, payroll, internal audit, taxes, facilities, fleet management and media services; and (ii) the payment of certain operating expenses of Enogex and its subsidiaries, including for compensation and benefits of operating personnel. The reimbursement for certain operating expenses is not subject to the maximum reimbursement for general and administrative expenses.

Enogex Intercompany Borrowing Agreement

On April 1, 2008, Enogex amended its intercompany borrowing agreement with OGE Energy to decrease the maximum amount permitted to be borrowed by Enogex from $200 million to $100 million. This agreement has a termination date of April 1, 2015. At December 31, 2008, there were no outstanding intercompany borrowings.

13. 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 were effective for the year ended December 31, 2006 for the Company. Also, as part of SFAS No. 158, an employer is required to measure the fair value of the funded status of a plan as of the date of its year-end statement of financial position, with limited exceptions. The requirement to measure plan assets and benefit obligations at fair value in accordance with SFAS No. 157 as of the date of the employer’s fiscal year-end statement of financial position was effective for fiscal years ending after December 15, 2008. The Company adopted this additional provision of SFAS No. 158 effective December 31, 2008 which had no impact to the Company as its measurement date and its fiscal year-end statement of financial position were the same.

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 ten 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 both 2008 and 2007, the Company made contributions to its pension plan of approximately $50.0 million 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 2009, the Company may contribute up to $50.0 million to its pension plan. The expected contribution to the pension plan during 2009 would be a discretionary contribution, anticipated to be in the form of cash, 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, 2008, the projected benefit obligation and fair value of assets of the Company’s pension plan and restoration of retirement income plan was approximately $554.3 million and $389.9 million, respectively, for an underfunded status of approximately $164.4 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, 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.

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, 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 a pension settlement charge and a retirement restoration plan settlement charge in 2007. The Company did not record a pension settlement charge during 2008. The pension settlement charge 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 Charge:				
2007	$ 13.3	$ 0.5	$ 2.9	$ 16.7
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 alters the manner in which pension plan assets and liabilities are valued for purposes of calculating required pension contributions, 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 were 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. In order to be in compliance with the Pension Protection Act, the Company has implemented the following changes to its defined benefit pension plan and defined contribution plan, as applicable: (i) effective January 1, 2008, the Company's defined benefit pension plan and defined contribution plans were amended to incorporate clarifying provisions and changes relating to the Pension Protection Act notice requirements and allow a non-spouse beneficiary to directly rollover an eligible distribution to an eligible individual retirement account ("IRA") or to a Roth IRA; (ii) effective January 1, 2008, the Company's defined benefit pension plan and defined contribution plans were amended to provide 100 percent vesting after completing three years of service; (iii) for the Company's defined benefit pension plan, effective January 1, 2008, that plan was amended to incorporate the new Pension Protection Act applicable mortality table and applicable interest rate under Internal Revenue Code Section 417(e)(3) for determining the actuarial equivalent value of a benefit that is converted to a lump sum; (iv) for the Company's defined contribution plan, effective January 1, 2008, that plan was amended to provide, in accordance with the Pension Protection Act that participants under age 55 may diversify amounts held in his/her TRASOP account out of the OGE Energy Corp Common Stock Fund into other investment funds; and (v) for the Company's defined contribution plan, that plan was amended to implement an eligible automatic contribution arrangement and provide for a qualified default investment alternative consistent with the Department of Labor regulations. The Company has taken steps to ensure that its plans, as well as participants and outside administrators, are aware of the changes.

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, 2008 and 2007:

December 31	**2008**	2007
Equity securities	**45 %**	61 %
Debt securities	**53 %**	37 %
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 or Fitch Ratings. The portfolio may invest up to ten 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 (ten 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 $58.2 million in 2009, $59.6 million in 2010, $62.0 million in 2011, $65.2 million in 2012, $64.3 million in 2013 and an aggregate of approximately $289.2 million in years 2014 to 2018. 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 ten 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. Prior to January 1, 2008, 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. Effective January 1, 2008, all regular, full-time, active employees whose age and years of credited service total or exceed 80 or have attained age 55 with three 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, 2008, the accumulated postretirement benefit obligation and fair value of assets of the Company's postretirement benefit plans was approximately $234.3 million and $57.0 million, respectively, for an underfunded status of approximately $177.3 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, 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.

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 2009 with the rates decreasing in subsequent years by one percentage point per year through 2012. 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)*	**2008**	2007	2006
Effect on aggregate of the service and interest cost components	**$ 2.2**	$ 2.3	$ 2.2
Effect on accumulated postretirement benefit obligations	**28.3**	26.9	29.2

ONE-PERCENTAGE POINT DECREASE

Year ended December 31*(In millions)*	**2008**	2007	2006
Effect on aggregate of the service and interest cost components	**$ 1.8**	$ 1.9	$ 1.8
Effect on accumulated postretirement benefit obligations	**23.4**	22.2	24.0

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. Management expects that the accumulated plan benefit obligation ("APBO") for the Company with respect to its postretirement medical plan will be reduced by approximately $70.9 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 $5.6 million annually. The $5.6 million in annual savings is comprised of a reduction of approximately $2.4 million from amortization of the $70.9 million gain due to the reduction of the APBO, a reduction in the interest cost on the APBO of approximately $2.6 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 $13.2 million in 2009, $14.3 million in 2010, $15.5 million in 2011, $16.4 million in 2012, $17.3 million in 2013 and an aggregate of approximately $96.1 million in years 2014 to 2018. The Company expects to receive Federal subsidy receipts provided by the Medicare Act of approximately $1.6 million in 2009, $1.8 million in 2010, $2.0 million in 2011, $2.2 million in 2012, $2.3 million in 2013 and an aggregate of approximately $14.0 million in years 2014 to 2018. The Company received approximately $0.8 million in Federal subsidy receipts in 2008.

Obligations and Funded Status

The following table presents the status of the Company's pension plan, the restoration of retirement income plan and the postretirement benefit plans for 2008 and 2007. The benefit obligation for the Company's pension plan and the restoration of retirement income plan represents the projected benefit obligation, while the benefit obligation for the postretirement benefit plans represents the accumulated benefit obligation. The accumulated benefit obligation differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. The accumulated benefit obligation for the pension plan and the restoration of retirement income plan at December 31, 2008 was approximately $485.1 million and $4.8 million, respectively. The accumulated benefit obligation for the pension plan and the restoration of retirement income plan at December 31, 2007 was approximately $459.0 million and $2.9 million, respectively. The details of the funded status of the pension plan, 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)*	**2008**	2007	**2008**	2007	**2008**	2007
Change in Benefit Obligation						
Beginning obligations	**$ (518.0)**	$ (575.2)	**$ (4.0)**	$ (9.8)	**$ (216.8)**	$ (225.4)
Service cost	**(19.0)**	(20.6)	**(0.7)**	(0.6)	**(3.7)**	(4.0)
Interest cost	**(31.4)**	(31.8)	**(0.4)**	(0.5)	**(13.4)**	(12.4)
Plan changes	**---**	16.7	**---**	0.1	**---**	---
Participants' contributions	**---**	---	**---**	---	**(6.0)**	(5.5)
Actuarial gains (losses)	**(19.5)**	15.4	**(2.7)**	(1.4)	**(9.2)**	15.2
Benefits paid	**40.9**	77.5	**0.5**	8.2	**14.8**	15.3
Ending obligations	**(547.0)**	(518.0)	**(7.3)**	(4.0)	**(234.3)**	(216.8)
Change in Plans' Assets						
Beginning fair value	**514.2**	519.4	**---**	---	**78.5**	74.0
Actual return on plans' assets	**(133.4)**	22.3	**---**	---	**(19.2)**	5.6
Employer contributions	**50.0**	50.0	**0.5**	8.2	**6.5**	8.7
Participants' contributions	**---**	---	**---**	---	**6.0**	5.5
Benefits paid	**(40.9)**	(77.5)	**(0.5)**	(8.2)	**(14.8)**	(15.3)
Ending fair value	**389.9**	514.2	**---**	---	**57.0**	78.5
Funded status at end of year	**$ (157.1)**	$ (3.8)	**$ (7.3)**	$ (4.0)	**$ (177.3)**	$ (138.3)

Net Periodic Benefit Cost

	Pension Plan			Restoration of Retirement Income Plan			Postretirement Benefit Plans		
Year ended December 31 *(In millions)*	**2008**	2007	2006	**2008**	2007	2006	**2008**	2007	2006
Service cost	**$ 19.0**	$ 20.6	$ 19.7	**$ 0.8**	$ 0.6	$ 0.7	**$ 3.7**	$ 4.0	$ 3.7
Interest cost	**31.4**	31.8	30.3	**0.4**	0.5	0.5	**13.4**	12.4	11.9
Return on plan assets	**(43.7)**	(43.9)	(38.4)	**---**	---	---	**(6.5)**	(5.9)	(5.6)
Amortization of transition obligation	**---**	---	---	**---**	---	---	**2.7**	2.7	2.7
Amortization of net loss	**9.3**	10.5	16.5	**0.3**	0.2	0.2	**4.0**	6.1	8.7
Amortization of recognized prior service cost	**0.9**	5.2	5.2	**0.6**	0.6	0.7	**1.9**	2.1	2.1
Settlement	**---**	16.7	17.1	**---**	2.3	---	**---**	---	---
Net periodic benefit cost (A)	**$ 16.9**	$ 40.9	$ 50.4	**$ 2.1**	$ 4.2	$ 2.1	**$ 19.2**	$ 21.4	$ 23.5

(A) In addition to the $19.0 million and $45.1 million in SFAS No. 87 net periodic benefit cost recognized in 2008 and 2007, respectively, OG&E also recognized an expense of approximately $10.1 million and a gain of approximately $10.1 million, respectively, related to the reversal of a portion of the regulatory asset identified as Deferred Pension Plan Expenses (see Note 1). The capitalized portion of the net periodic pension benefit cost was approximately $4.0 million, $5.5 million and $7.6 million at December 31, 2008, 2007 and 2006, respectively. The capitalized portion of the net periodic postretirement benefit cost was approximately $4.6 million, $4.8 million and $5.0 million at December 31, 2008, 2007 and 2006, respectively.

Rate Assumptions

	Pension Plan and Restoration of Retirement Income Plan			Postretirement Benefit Plans		
Year ended December 31	**2008**	2007	2006	**2008**	2007	2006
Discount rate	**6.25%**	6.25%	5.75%	**6.25%**	6.25%	5.75%
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	**2014**	2013	2012

N/A - not applicable

The overall expected rate of return on plan assets assumption remained at 8.50 percent in 2007 and 2008 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 $2.1 million and $1.6 million at December 31, 2008 and 2007, 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, rollover 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, on any business day, by participants to other available investment options. The Company contributed approximately $8.6 million, $7.6 million and $6.8 million during 2008, 2007 and 2006, 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.

14. Report of Business Segments

The Company's business is divided into four segments for financial 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 and, as a result, OERI is no longer a subsidiary of Enogex. Other Operations primarily included the operations of the holding company. 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, 2008, 2007 and 2006.

2008	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
(In millions)							
Operating revenues	**$ 1,959.5**	**$ 625.9**	**$ 1,053.2**	**$ 1,529.4**	**$ ---**	**$ (1,097.3)**	**$ 4,070.7**
Cost of goods sold	**1,114.9**	**479.7**	**806.4**	**1,509.5**	**---**	**(1,092.5)**	**2,818.0**
Gross margin on revenues	**844.6**	**146.2**	**246.8**	**19.9**	**---**	**(4.8)**	**1,252.7**
Other operation and maintenance(A)	**351.6**	**48.2**	**87.3**	**12.9**	**(2.0)**	**(5.8)**	**492.2**
Depreciation and amortization	**155.0**	**17.5**	**37.1**	**0.2**	**7.7**	**---**	**217.5**
Impairment of assets	**---**	**---**	**0.4**	**---**	**---**	**---**	**0.4**
Taxes other than income	**59.7**	**12.7**	**4.6**	**0.4**	**3.1**	**---**	**80.5**
Operating income (loss)	**$ 278.3**	**$ 67.8**	**$ 117.4**	**$ 6.4**	**$ (8.8)**	**$ 1.0**	**$ 462.1**
Total assets	**$ 4,851.2**	**$ 1,265.9**	**$ 836.9**	**$ 235.1**	**$ 2,469.1**	**$ (3,139.7)**	**$ 6,518.5**
Capital expenditures	**$ 840.1**	**$ 93.3**	**$ 240.2**	**$ ---**	**$ 12.9**	**$ (2.0)**	**$ 1,184.5**

(A) In 2004, the Company adopted a standard costing model utilizing a fully loaded activity rate (including payroll, benefits, other employee related costs and overhead costs) to be applied to projects eligible for capitalization or deferral. In March 2008, the Company determined that the application of the fully loaded activity rates had unintentionally resulted in the over-capitalization of immaterial amounts of certain payroll, benefits, other employee related costs and overhead costs in prior years. To correct this issue, in March 2008, the Company recorded a pre-tax charge of approximately $9.5 million ($5.8 million after tax, or $0.06 per basic and diluted share) as an increase in Other Operation and Maintenance Expense in the Condensed Consolidated Statements of Income for the three months ended March 31, 2008 and a corresponding $8.6 million decrease in Construction Work in Progress and $0.9 million decrease in Other Deferred Charges and Other Assets related to the regulatory asset associated with storm costs in the Condensed Consolidated Balance Sheets as of March 31, 2008.

2007	Electric Utility	Transportation and Storage (B)	Gathering and Processing (B)	Marketing	Other Operations	Eliminations	Total
(In millions)							
Operating revenues	$ 1,835.1	$ 529.1	$ 799.4	$ 1,541.2	$ ---	$ (907.2)	**$** 3,797.6
Cost of goods sold	1,025.1	396.4	603.5	1,513.4	---	(903.7)	2,634.7
Gross margin on revenues	810.0	132.7	195.9	27.8	---	(3.5)	1,162.9
Other operation and maintenance	320.7	48.5	72.1	10.1	(11.3)	(3.3)	436.8
Depreciation and amortization	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 (B)	Gathering and Processing (B)	Marketing	Other Operations	Eliminations	Total
(In millions)							
Operating revenues	$ 1,745.7	$ 508.7	$ 704.3	$ 1,941.3	$ ---	$ (894.4)	**$** 4,005.6
Cost of goods sold	950.0	383.1	536.7	1,927.1	---	(894.4)	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 and amortization	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

(B) Beginning in 2008, Enogex began bifurcating intercompany natural gas purchase and sale transactions based upon the operational sources of the natural gas versus recognizing transactions on a net basis in 2006 and 2007. As a result, certain 2006 and 2007 transactions have been reclassified within the segment disclosure for consistency of presentation. However, certain 2006 and 2007 transactions have not been reclassified as the information is not available. As a result of this reclassification, there is no impact on the Company's consolidated Operating Revenues or Cost of Goods Sold.

15. 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)*	2009	2010	2011	2012	2013	2014 and Beyond
Operating lease obligations						
OG&E railcars	$ 3.9	$ 3.8	$ 38.0	$ ---	$ ---	$ ---
Enogex noncancellable operating leases	4.2	2.5	1.6	0.4	---	---
Total operating lease obligations	$ 8.1	$ 6.3	$ 39.6	$ 0.4	$ ---	$ ---

Payments for operating lease obligations were approximately $7.3 million, $6.7 million and $7.6 million in 2008, 2007 and 2006, 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 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. In April 2008, OG&E amended its contract to add 55 new railcars for approximately $3.5 million. 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 $31.5 million. In mid-February 2009, OG&E expects to enter into a new short-term lease agreement to add 270 new railcars for approximately $1.2 million to satisfy the requirements of its new coal transportation contracts with BNSF Railway and Union Pacific as discussed below. The expiration dates of the lease agreement are expected to be: (i) six months from the effective date of the lease agreement for 135 cars and (ii) one year from the effective date of the lease agreement for the other 135 cars. 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.

OG&E Coal Transportation Contracts

OG&E has transportation contracts for the transportation of coal to its coal-fired power plants. OG&E's transportation contracts expired on December 31, 2008. On December 19, 2008, OG&E entered into a new rail transportation agreement with the BNSF Railway for the movement of coal to OG&E's Sooner power plant. OG&E has also filed a complaint at the Surface Transportation Board ("STB") requesting the establishment of reasonable rates, practices and service terms for the transportation of coal from Union Pacific served mines in the southern Powder River Basin, Wyoming to OG&E's Muskogee power plant. The timing of the completion of this proceeding is uncertain at this time. The effect of the new BNSF Railway agreement and the anticipated rail rate prescription from the STB for rail transportation to OG&E's Sooner and Muskogee power plants is expected to cause an approximate 50 percent increase in OG&E's delivered coal prices.

Public Utility Regulatory Policy Act of 1978

At December 31, 2008, OG&E has agreements with two qualifying cogeneration facilities ("QF") having terms of 15 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 QF. The rate for such power to be paid by OG&E was approved by the OCC.

The rate generally consists of two components: one is a rate for actual electricity purchased from the QF by OG&E; the other is a capacity charge, which OG&E must pay the QF for having the capacity available. However, if no electrical power is made available to OG&E for a period of time (generally three months), OG&E's obligation to pay the capacity charge is suspended. The total cost of cogeneration payments is recoverable in rates from customers. 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 2008, 2007 and 2006, OG&E made total payments to cogenerators of approximately $152.8 million, $156.8 million and $162.6 million, respectively, of which approximately $84.4 million, $88.9 million and $94.9 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: 2009 – $86.8 million, 2010 – $85.0 million, 2011 – $83.1 million, 2012 – $81.0 million and 2013 – $81.0 million.

Fuel Minimum Purchase Commitments

OG&E purchased necessary fuel supplies of coal and natural gas for its generating units of approximately $215.1 million, $190.2 million and $195.1 million for the years ended December 31, 2008, 2007 and 2006, respectively. OG&E has entered into purchase commitments of necessary fuel supplies of approximately: 2009 – $320.7 million, 2010 – $114.1 million, 2011 – $65.2 million, 2012 – $3.9 million, 2013 – $3.9 million and 2014 and Beyond – $19.5 million.

Natural Gas Units

In August 2008, OG&E issued a request for proposal ("RFP") for gas supply purchases for periods from November 2008 through March 2009, which accounted for approximately 15 percent of its projected 2009 natural gas requirements. The contracts resulting from this RFP are tied to various gas price market indices that will expire in 2009. Additional gas supplies to fulfill OG&E's remaining 2009 natural gas requirements will be acquired through additional RFPs in early to mid-2009, along with monthly and daily purchases, all of which are expected to be made at market prices.

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 through 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 $5.4 million for each of the years 2009 through 2012; $6.5 million for each of the years 2013 and 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 ten 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 272 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 MEP project includes construction by MEP of a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. Enogex currently estimates that its capital expenditures related to this project will be approximately $94 million.

On July 25, 2008, the FERC issued its order approving the MEP project including the approval of a limited jurisdiction certificate authorizing the Enogex lease agreement to MEP. Further, the FERC order rejected all claims raised by protestors regarding the lease agreement. Accordingly, Enogex is proceeding with the construction of facilities necessary to implement this service. On August 25, 2008, one protestor filed a request for rehearing. The FERC has not yet ruled on the request for rehearing and the current timing of any FERC action cannot be reasonably predicted. The MEP project is currently expected to be in service during the second quarter of 2009.

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. Oral arguments were made to the Tenth Circuit on September 25, 2008. No ruling was made on the oral arguments and the court took the case under advisement. 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 the Fourth Amended Petition 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 Fourth Amended Petition of the Price I case. OG&E and Enogex Inc. were not named in this case, but two subsidiary entities of the Company were named in this 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.

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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.

OERI Self-Disclosure Matter

On November 13, 2007, OERI orally self-reported to the FERC Office of Enforcement ("OE") a 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 into the Transaction and in December 2007, at the OE's request, OERI provided a written report to the OE of that internal investigation. Subsequently, the OE advised OERI that it had commenced a preliminary, non-public investigation into compliance matters relating to the Transaction. In February 2008, the OE submitted to OERI discovery requests relating to various aspects of the Transaction and OERI's internal investigation. OERI responded to the discovery requests at the end of February 2008. OERI also informed the OE that it was continuing to review other transactions to determine whether any additional transactions may have violated the FERC's capacity release rules. On February 2, 2009, following informal conferences with the OE, OERI submitted a written summary of two additional transactions that presented possible compliance issues relating to the FERC's capacity release rules. The OE notified OERI on February 6, 2009 with a notification that it had decided to terminate its investigation without any remedial or other action regarding any of the three transactions reported. This matter is now considered closed.

Pipeline Rupture

On November 14, 2008, a natural gas gathering pipeline owned by Enogex ruptured in Grady County, near Alex, Oklahoma, resulting in a fire that caused injuries to one resident and destroyed three residential structures. The cause of the rupture is not known and an investigation of the incident is ongoing. The damaged pipeline has been repaired and the pipeline is back in service. It is anticipated that third-party damages related to this incident will not be material to the Company.

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. In September 2008, the plaintiffs filed an application with the OCC asking the OCC to modify its order which authorizes OG&E to collect the challenged franchise fee charges. A procedural schedule and notice requirements for the matter were established by the OCC on December 4, 2008. The OCC expects to hear arguments for a motion to dismiss on March 26, 2009. OG&E believes that this case is without merit.

Oxley Litigation

OG&E has been sued by John C. Oxley D/B/A Oxley Petroleum et al. in the District Court of Haskell County, Oklahoma. This case has been pending for more than 11 years. The plaintiffs' alleged that OG&E breached the terms of contracts covering several wells by failing to purchase gas from the plaintiff in amounts set forth in the contracts. The plaintiffs' most recent Statement of Claim describes approximately $2.7 million in take-or-pay damages (including interest) and approximately $36 million in contract repudiation damages (including interest), subject to the limitation described below. In 2001, OG&E agreed to provide the plaintiffs with approximately $5.8 million of consideration and the parties agreed to arbitrate the dispute. Consequently, OG&E will only be liable for the amount, if any, of an arbitration award in excess of $5.8 million. OG&E expects the arbitration to occur in the first half of 2009. While the Company cannot predict the precise outcome of the arbitration, based on the information known at this time, OG&E believes that this lawsuit will not have a material adverse effect on the Company's consolidated financial position or results of operations.

Potential Collateral Requirements

In the event Moody's or Standard & Poor's were to lower the Company's senior unsecured debt rating to a below investment grade rating, at December 31, 2008, the Company would have been required to post approximately $0.9 million of collateral to satisfy its obligation under its financial and physical contracts. In addition, the Company could be required to provide additional credit assurances in future dealings with third parties, which could include letters of credit or cash collateral.

Environmental Laws and Regulations

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. 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. OG&E and Enogex handle some materials subject to the requirements of the Federal Resource Conservation and Recovery Act and the Federal Water Pollution Control Act of 1972, as amended ("Clean Water Act") and comparable state statutes, prepare and file reports and documents pursuant to the Toxic Substance Control Act and the Emergency Planning and Community Right to Know Act and obtain 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 OG&E's or Enogex's facilities. Historically, OG&E's and 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 increase the cost of conducting business.

Approximately $1.6 million and $32.1 million, respectively of the Company's capital expenditures budgeted for 2009 and 2010 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 $40.0 million during 2009 as compared to approximately $40.7 million in 2008. The Company continues to evaluate its environmental management systems to ensure compliance with existing and proposed environmental legislation and regulations and to better position itself in a competitive market.

Air

On March 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. Various petitions and appeals related to this decision have been made and are not yet resolved. On February 6, 2009, the EPA filed a motion to dismiss their earlier request for the U.S. Supreme Court to review the 2008 decision. Industry interests are still seeking the U.S. Supreme Court review in the case. The EPA has stated that it intends to draft mercury rules under the Federal Clean Air Act. The Company cannot predict the outcome of the Federal litigation at this time. Until the rule was vacated, the CAMR required mercury monitoring to begin in 2009. Accordingly, OG&E installed mercury monitoring equipment on all five of its coal units. The cost of the monitoring equipment was approximately $5.0 million in 2007 and approximately $0.4 million in 2008. Because the CAMR litigation is ongoing, the cost to install mercury controls is uncertain at this time but may be significant, particularly if the EPA develops more stringent requirements. Because of the uncertainty caused by the litigation regarding the CAMR, the promulgation of an Oklahoma rule that would apply to existing facilities has been delayed. 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 Oklahoma Department of Environmental Quality ("ODEQ") informally notified affected utilities that they would be required to perform a study to determine their impact on visibility in 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 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 cost for this alternative compliance plan, including the BART compliance plan for the Seminole power plant (the alternative compliance plan and the BART compliance plan are collectively referred to herein as the "alternative plan"), was estimated at approximately $470 million in March 2007. The alternative plan included 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 comments to the ODEQ on OG&E's alternative plan. On November 16, 2007, the ODEQ notified OG&E that additional analysis would be required before the OG&E alternative plan could be accepted. On May 30, 2008, OG&E filed the results with the ODEQ for the affected generating units as well as withdrawing its alternative plan filed in March 2007. In the May 30, 2008 filing, OG&E indicated its intention to install low NOX combustion technology at its affected generating stations and to continue to burn low sulfur coal at its four coal-fired generating units at its Muskogee and Sooner generating stations. The capital expenditures associated with the installation of the low NOX combustion technology are expected to be approximately $110 million. OG&E believes that these control measures will achieve visibility improvements in a cost-effective manner. OG&E did not propose the installation of scrubbers at its four coal-fired generating units because OG&E concluded that, consistent with the EPA's regulations on BART, the installation of scrubbers (at an estimated cost of $1.7 billion) would not be cost-effective. OG&E previously reported an expectation that a compliance plan would be approved by the EPA by December 31, 2008; however, submission of the overall compliance plan by the ODEQ (which will include OG&E's compliance plan previously submitted to the ODEQ) has been delayed and the current timing of the EPA approval cannot be reasonably predicted. In a letter dated November 4, 2008, the EPA notified the ODEQ that they had completed their review of BART applications for all affected sources in Oklahoma, which included OG&E. The EPA did not approve or disapprove the applications, however, additional information was requested from the ODEQ by the EPA regarding OG&E's plan. The Company cannot predict what action the EPA or the ODEQ will take in response to OG&E's May 30, 2008 filing or the November 4, 2008 letter from the EPA. Until the compliance plan is approved, the total cost of compliance, including capital expenditures, cannot be estimated by OG&E with a reasonable degree of certainty. 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.

The original deadline for the ODEQ to submit a state implementation plan for regional haze that includes final BART determinations was December 17, 2007. The ODEQ did not meet this deadline. On January 15, 2009, the EPA published a rule that gives the ODEQ two years to complete the state implementation plan. If the ODEQ fails to meet this deadline, the EPA can issue a Federal implementation plan.

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 2008, 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 2008. Also, during 2008, OG&E received proceeds of approximately $0.4 million from the annual EPA spot (year 2008) and seven-year advance (year 2015) allowance auctions that were held in March 2008.

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. The regulations required that OG&E achieve a NOX emission level of 0.40 lbs/MMBtu for these boilers which began in 2008. OG&E's average NOX emissions from its coal-fired boilers for 2008 were approximately 0.32 lbs/MMBtu. 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.

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.

Currently, the EPA has designated Oklahoma “in attainment” with the ambient standard for ozone of 0.08 parts per million (“PPM”). In March 2008, the EPA lowered the ambient primary and secondary standards to 0.075 PPM. Oklahoma has until March 2009 to designate any areas of non-attainment within the state, based on ozone levels in 2006 through 2008. Following the state’s designation, the EPA is expected to determine a final designation by March 2010. States will be required to meet the ambient standards between 2013 and 2030, with deadlines depending on the severity of their ozone level. Oklahoma City and Tulsa are the most likely areas to be designated non-attainment in Oklahoma. The Company cannot predict the final outcome of this evaluation or its timing or affect on OG&E’s or Enogex’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. 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 of Oklahoma’s demonstration is currently unknown.

In July 2008, OG&E received a request for information from the EPA regarding Clean Air Act compliance at OG&E’s Muskogee and Sooner generating plants. In recent years, the EPA has issued similar requests to numerous other electric utilities seeking to determine whether various maintenance, repair and replacement projects should have required permits under the Clean Air Act’s new source review process. OG&E believes it has acted in full compliance with the Clean Air Act and new source review process and is cooperating with the EPA. On August 28, 2008, OG&E submitted information to the EPA and submitted additional information on October 31, 2008. OG&E cannot predict what, if any, further actions the EPA may take with respect to this matter.

At December 31, 2008, OG&E had received Title V permits for all of its generating stations and intends to continue to renew these permits as necessary. 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 and became effective July 1, 2008. Air permit fees for OG&E’s generating stations were approximately $0.8 million in 2008 and for Enogex’s facilities were approximately $0.3 million in 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. 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 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 2008, OG&E obtained refunds of approximately $2.2 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") renewal permits in February 2008 from the state of Oklahoma. OG&E filed an OPDES renewal application with the state of Oklahoma on August 4, 2008 for its Seminole power plant and received a draft permit for review on January 9, 2009. OG&E is currently reviewing this draft permit to determine if it is reasonable in its requirements and allows operational flexibility.

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. 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 required 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. Additionally, on April 14, 2008, the U.S. Supreme Court granted writs of certiorari and will review the question of whether the Section 316(b) rules authorize the EPA to compare costs with benefits in determining the best technology available for minimizing "adverse environmental impact" at cooling water intake structures. 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 comprehensive demonstration studies, capital and/or operating costs may increase at any affected OG&E generating facility. OG&E expects a ruling from the U.S. Supreme Court on the Section 316(b) rules in mid-2009.

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 16 below and in Item 3 of this 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.

16. 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, 2008, approximately 88 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, nine percent to the APSC and three 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

Acquisition of Redbud 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 were 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 owned the 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 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 were subject to an order from the FERC authorizing the contemplated transactions and an order from the OCC approving the prudence of the transactions and an appropriate reasonable recovery mechanism, and other customary conditions.

On September 16, 2008, the FERC issued an order approving the Redbud acquisition. In the order, the FERC concluded that the Redbud acquisition could harm horizontal competition by increasing market concentration. However, the FERC concluded that, since OG&E had committed to construct specific upgrades on the system, these would be adequate mitigation measures. Accordingly, the FERC conditioned its approval of the Redbud acquisition on OG&E's completion of these upgrades. OG&E is required to file quarterly updates describing the progress of the transmission upgrades, the first of which was filed December 16, 2008. OG&E also must notify the FERC of any change in circumstances regarding these projects. During the approximately 27-month period required to construct the transmission upgrades, the FERC did not require any interim mitigation beyond the limits of OG&E's market-based rate authority and the SPP market monitoring programs currently in place. In addition, the FERC found that the proposed transaction would have no adverse effects on vertical market power, on wholesale rates, or on state or Federal regulation. The FERC also determined that the transaction presented no cross-subsidy concerns. Finally, the FERC rejected various arguments raised by AES that sought to expand the scope of the FERC proceeding or to impose additional conditions on the Redbud acquisition. On September 24, 2008, the OCC issued an order approving the Redbud acquisition. OG&E closed on the Redbud acquisition on September 29, 2008. OG&E implemented a rider at the end of September 2008 to recover the Oklahoma jurisdiction revenue requirement until new rates are implemented that include Redbud's net investment, operation and maintenance expense, depreciation expense and ad valorem taxes.

Cancelled Red Rock Power Plant and Storm Cost Recovery Rider

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 coal-fired 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. Specifically, OG&E requested authorization to sell approximately $14.7 million of its SO2 allowances and to retain 100 percent of the proceeds to offset the $14.7 million of Red Rock costs. Under a prior order of the OCC, 90 percent of the proceeds from sales of SO2 allowances were to be credited to ratepayers. Any portion of the $14.7 million of deferred costs that the OCC did not approve for recovery by OG&E was to be expensed. In its response to OG&E's Red Rock cost recovery application, the OCC Staff recommended, among other things, that OG&E sell SO2 allowances and retain 100 percent of the proceeds from the sale to be used to offset OG&E's December 2007 ice storm costs. These ice storm costs were included as part of the regulatory asset balance of approximately $35.9 million at December 31, 2007 (see Note 1), in accordance with a prior order of the OCC, pending recovery in a future rate case. On June 27, 2008, OG&E filed an application requesting a Storm Cost Recovery Rider ("SCRR") for the years 2007 through 2009 to recover excess storm damage costs and, at the same time, filed a motion to consolidate for hearing the Red Rock application and the SCRR application. On July 24, 2008, a settlement agreement was signed by all the parties involved in the two cases. Under the terms of the settlement agreement, OG&E will: (i) recover approximately $7.2 million, or 50 percent, of the Oklahoma jurisdictional portion of the Red Rock power plant deferred costs through a regulatory asset, (ii) amortize the Red Rock regulatory asset over a 27-year amortization period and earn the OCC's authorized rate of return beginning with OG&E's next rate case, (iii) accrue carrying costs on the debt portion of the Red Rock regulatory asset from October 1, 2007 until the date OG&E begins to recover the regulatory asset through the base rates established in OG&E's next rate case, (iv) recover the OCC Staff and Attorney General consulting fees of approximately $0.3 million related to the Red Rock pre-approval case, in OG&E's next rate case by amortizing this over a two-year period, (v) recover approximately $33.7 million of the 2007 storm costs regulatory asset, which resulted in a write-down of approximately $1.5 million, (vi) implement the SCRR to recover OG&E's actual storm expense for the four-year period from 2006 through 2009, (vii) retain the first $3.4 million from the sale of excess SO2 allowances, (viii) reduce storm costs recovered through the SCRR by the proceeds from the sale of SO2 allowances above the amount retained by OG&E and (ix) earn the most recent OCC authorized return on the unrecovered storm cost balance through the SCRR. On August 22, 2008, the OCC issued an order approving the settlement agreement and the SCRR was implemented in September 2008. In June 2008, OG&E wrote down the Red Rock deferred cost and the storm costs to their net present value, which resulted in a pre-tax charge of approximately $9.0 million, which is currently included in Deferred Charges and Other Assets with an offset in Other Expense on the Company's Consolidated Financial Statements.

Renewable Energy Filing

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, on December 8, 2008, OG&E issued an RFP to wind developers for construction of up to 300 MWs of new capability. OG&E intends to add the new capacity to its power-generation portfolio no later than the end of 2010.

OG&E filed an application on May 19, 2008 with the OCC requesting pre-approval to recover from Oklahoma customers the cost to construct a transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma at a cost of approximately $211 million. This transmission line is a critical first step to increased wind development in western Oklahoma. In the application, OG&E also requested authorization to implement a recovery rider to be effective when the transmission line is completed and in service, which is expected during 2010. Finally, the application requested the OCC to approve new renewable tariff offerings to OG&E's Oklahoma customers. On July 11, 2008, the OCC Staff filed responsive testimony recommending approval of OG&E's renewable plan and the Oklahoma Industrial Energy Consumers opposed OG&E's request. A settlement agreement was signed by all parties in the matter on July 31, 2008. Under the terms of the settlement agreement, the parties agreed that the Company will: (i) receive pre-approval for construction of a transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma and a conclusion that the construction costs of the transmission line are prudent, (ii) receive a recovery rider for the revenue requirement of the $218 million in construction costs and AFUDC when the transmission line is completed and in service until new rates are implemented in a subsequent rate case and (iii) to the extent the construction costs and AFUDC for the transmission line exceed $218 million OG&E be permitted to show that such additional costs are prudent and allowed to be recovered. On September 11, 2008, the OCC issued an order approving the settlement agreement. Separately, on July 29, 2008, the SPP Board of Directors approved the proposed transmission line discussed above. On February 2, 2009, OG&E received SPP approval to begin construction of the transmission line and the associated Woodward Extra High Voltage substation.

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. In September 2008, the OCC issued an order approving the fuel, purchased power and purchase gas adjustment clause cost recoveries for calendar year 2006.

Pending Regulatory Matters

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. In July 2008, rates were implemented in an annual amount of approximately $2.4 million, subject to refund. Several settlement conferences have been held with the most recent being on November 17 and 18, 2008. Since the November 17 and 18, 2008 settlement conferences, the parties have continued to engage in settlement discussions.

OG&E Arkansas Rate Case Filing

On August 29, 2008, OG&E filed with the APSC an application for an annual rate increase of approximately $26.4 million to recover, among other things, costs for investments including the Redbud Facility and improvements in its system of power lines, substations and related equipment to ensure that OG&E can reliably meet growing customer demand for electricity, and a return on equity of 12.25 percent. In January 2009, the APSC Staff recommended a $12.0 million rate increase based on a 10.5 percent return on equity. The Attorney General's consultant recommended a return on equity at the current authorized level of 10.0 percent and stated that his analysis identified at least $10.9 million in reductions to OG&E's rate increase request. A hearing is scheduled for April 7, 2009. An order from the APSC is expected in June 2009 with new rates targeted for implementation in July 2009.

OG&E 2008 Storm Cost Filing

On October 30, 2008, OG&E filed an application with the APSC requesting authority to defer its 2008 storm costs that exceed the amount recovered in base rates. The application also requests the APSC to provide for recovery of the deferred 2008 storm costs in OG&E's pending rate case. On December 19, 2008, the APSC issued an order authorizing OG&E to defer approximately $0.6 million in 2008 for incremental storm costs in excess of the amount included in OG&E's rates. OG&E was also authorized to seek recovery in its pending rate case but was not guaranteed recovery. At December 31, 2008, these incremental storm costs were approximately $0.6 million, which has been recorded as a regulatory asset (see Note 1).

OG&E 2009 Oklahoma Rate Case Filing

Beginning in October 2008, OG&E began developing a rate case filing for the Oklahoma jurisdiction. On January 20, 2009, OG&E notified the OCC that it will make its planned Oklahoma rate case filing on or about February 26, 2009. OG&E is finalizing the preparation of the rate case and expects to request an increase of between $100 million and $110 million. The case is expected to proceed through the first half of 2009. If an increase is approved by the OCC, electric rates would likely be implemented in September 2009 at the earliest.

OG&E System Hardening Filing

In December 2007, a major ice storm affected OG&E's service territory which resulted in a large number of customer outages. The OCC requested its Staff to review and determine if a rulemaking was warranted. The OCC Staff issued numerous data requests and is in the process of determining if other regulatory jurisdictions have policies or rules requiring that electric transmission and distribution lines be placed underground. The OCC Staff also surveyed customers. On June 30, 2008, the OCC Staff submitted a report entitled, "Inquiry into Undergrounding Electric Facilities in the State of Oklahoma." OG&E formed a plan to place facilities underground (sometimes referred to as system hardening) with capital expenditures of approximately $115 million over five years for underground facilities, as well as $10 million annually for enhanced vegetation management. On December 2, 2008, OG&E filed an application with the OCC requesting approval of it proposed system hardening plan with a recovery rider. On February 5, 2009, a procedural schedule was set in this matter with a hearing scheduled for March 25, 2009. The Company expects to receive an order from the OCC in the second quarter of 2009, with a targeted implementation date for the program and rider in the third quarter of 2009.

Review of OG&E's Fuel Adjustment Clause for Calendar Year 2007

The OCC routinely audits activity in OG&E's fuel adjustment clause for each calendar year. In September 2008, the OCC Staff filed an application for a prudence review of OG&E's 2007 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 16, 2009, on which date the MFRs were submitted by OG&E. A procedural schedule has not been established in this matter.

Security Enhancements

On January 15, 2009, OG&E filed an application with the OCC to amend its security plan. OG&E is seeking approval of new security projects and cost recovery through the previously authorized security rider. The annual revenue requirement is approximately $0.9 million. OG&E expects to receive an order from the OCC in the third quarter of 2009. A procedural schedule has not been established in this matter.

Southwest Power Pool Transmission/Substation Project

In January 2009, OG&E received notification from the SPP to begin construction on approximately 50 miles of new 345kV transmission line and certain substation upgrades at OG&E's Sunnyside substation, among other projects. The line will extend from OG&E's Sunnyside substation near Ardmore, Oklahoma, to a point approximately one-half of the distance to the Hugo substation owned by the Western Farmers Electric Cooperative near Hugo, Oklahoma. The line and substation improvements are estimated to cost approximately $96 million. OG&E intends to begin preliminary line routing and acquisition of rights-of-way in early 2009. When construction is completed, which is expected in April 2012, the SPP will allocate a portion of the annual revenue requirement to OG&E customers according to the base-plan funding mechanism as provided in the SPP tariff for application to such improvements.

OGE Energy and Electric Transmission America Joint Venture

In July 2008, OGE Energy and Electric Transmission America, a joint venture of subsidiaries of American Electric Power and MidAmerican Energy Holdings Co., formed a transmission joint venture to construct high-capacity transmission line projects in western Oklahoma. The Company will own 50 percent of the joint venture. The joint venture is intended to allow the companies to lead development of renewable wind by sharing capital costs associated with the planned transmission construction. Work on the joint venture projects is scheduled to begin in late 2009 and is targeted for completion by the end of 2013. The joint venture projects are subject to creation by the SPP of a cost allocation method that would spread the total cost across the SPP region. The project also required approval from the FERC. OGE Energy filed an application with the FERC in October 2008 for cost recovery of these projects subject to SPP and FERC approval for these projects. On December 2, 2008, the FERC granted the joint venture's request for transmission rate incentives for the initial projects, established a base return on equity for initial projects, approved certain accounting treatments for the initial projects and set the formula rate and accompanying protocols for hearing and settlement discussions. The joint venture's initial projects will include 765 kilovolt lines from Woodward 120 miles northwest to Guymon in the Oklahoma Panhandle and from Woodward 50 miles north to the Kansas border. An SPP study estimates cost for the two projects to be approximately $500 million, of which OGE Energy's portion will be approximately $250 million.

Enogex 2009 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, Enogex 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, Enogex has filed for fixed fuel percentages for the East Zone and the West Zone, respectively. On November 21, 2008, Enogex made its annual filing to establish the fixed fuel percentages for its East Zone and West Zone for calendar year 2009 ("2009 Fuel Year"). The FERC accepted the proposed zonal fuel percentages for the 2009 Fuel Year by an order dated January 8, 2009.

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 also filed protests.

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. By order of February 28, 2008, the FERC extended the time period in this docket by 120 days and encouraged the parties to settle. No action has yet been taken by the FERC and the parties are currently in settlement negotiations.

On November 13, 2007, one of the protesting intervenors filed to consolidate the Enogex rate case with a separate Enogex application pending before the FERC allowing Enogex to lease firm capacity to MEP and with separate applications filed by MEP with the FERC for a certificate to construct and operate the new MEP pipeline and to lease firm capacity from Enogex. Additional pleadings were also filed by this intervenor after the initial protest and Enogex and MEP separately opposed this intervenor's assertions. By order dated July 25, 2008, the FERC approved the MEP project and denied the intervenors' request for consolidation of the MEP proceedings with the Enogex rate case. The intervenor has filed a request for rehearing in the MEP project and lease proceedings. The FERC has not yet acted on the request. Enogex has not, as of yet, placed the increased rates into effect while settlement negotiations continue. Enogex has a regulatory obligation to file its next rate case no later than October 1, 2010 to comply with the FERC's requirement for triennial filings, but plans to file a new rate case during the first half of 2009. While Enogex has yet to finalize various components of the new filing, Enogex is finalizing agreements with East Zone shippers interested in firm Section 311 service on the East Zone of its system and anticipates offering in the near-term a limited firm Section 311 service on the East Zone for the first time.

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, OG&E submitted: (i) a compliance filing containing the specified revisions to OG&E'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. On April 4, 2008, the FERC rejected OG&E's April 20, 2006 request for rehearing and approved in part and rejected in part OG&E's April 20, 2006 compliance filing. The April 4, 2008 order directed OG&E to evaluate whether any refunds are required to comply with the April 4, 2008 order and to: (i) make any necessary refunds, or (ii) file a report with the FERC stating that no refunds are due. Refunds would apply only to new market-based sales made or new market-based contracts entered into after the March 21, 2006 order. The April 4, 2008 order also directed OG&E to make another compliance filing to revise its market-based rate tariffs to adhere to the FERC's June 21, 2007 final rule that revised standards for market-based rate sales of electric energy, capacity and ancillary services. On May 5, 2008, OG&E submitted a compliance report stating that no refunds were due. On May 30, 2008, OG&E and OERI submitted to the FERC a change in status report notifying the FERC that OG&E had entered into a contract with Westar Energy under which

OG&E agreed to purchase 300 MWs of capacity and energy for the periods from May 1, 2008 through August 31, 2008, and from May 1, 2009 through August 31, 2009. OG&E and OERI explained that this purchase agreement was not material to the FERC's grant of market-based rate status to OG&E and OERI. The FERC has not yet acted on OG&E and OERI's May 30, 2008 change of status filing. On October 27, 2008, OG&E and OERI submitted to the FERC another change of status filing notifying FERC that OG&E had acquired a 51 percent interest in the Redbud Facility in Oklahoma, which increases the size of its generation resources by 610 MW. This filing indicated that: (i) OG&E's acquisition of the Redbud Facility does not reflect a material departure from the characteristics relied upon in granting OG&E/OERI market-based rate authority; (ii) OG&E/OERI continue to lack generation market power in first-tier markets; and (iii) OG&E's acquisition of the Redbud Facility does not effect OG&E's or OERI's previous analysis on transmission market power, affiliate abuse or barriers to entry. The FERC has not yet acted on OG&E's and OERI's October 27, 2008 change of status filing.

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 November 2008, OG&E completed its periodic NERC compliance audit. Resolution of any audit findings is expected in 2009; however, OG&E does not expect the resolution of any audit findings to have a material impact on its operations. The Company is subject to a NERC readiness evaluation and compliance audit every three years. The next readiness evaluation is scheduled for 2010 and the next compliance audit is scheduled for 2011.

National Legislative Initiatives

In October 2008, Congress enacted and the President signed into law the Emergency Economic Stabilization Act of 2008 which contains, among other things, provisions designed to provide programs to: (i) address the nation's credit liquidity problems; (ii) provide disaster relief for adversely affected communities; (iii) preserve the value of homes, retirement accounts and promote job creation; and (iv) implement a wide range of tax provisions, including several of particular interest to the investor-owned utility sector. Among the tax provisions benefiting the utility sector are the extension of tax credits for renewable energy production, carbon mitigation and clean coal technology, plug-in hybrid vehicles, increasing residential and commercial building energy efficiency, energy efficient appliances and accelerated depreciation for smart meters and smart grid systems. Of particular interest to the Company is the extension through 2009 of the renewable energy production tax credit that was scheduled to expire at the end of 2008, which plays a prominent role regarding the financing and economics of wind energy projects.

In December 2008, Congress enacted and the President signed into law legislation providing some relief for companies regarding mandatory pension payment obligations that had become complicated by the economic downturn. This legislation allowed companies greater latitude in meeting their pension obligations through temporary adjustments regarding mandatory minimum distributions and plan funding targets. The utility and natural gas midstream industries supported this legislation and is seeking broader temporary adjustments for pension plan funding in 2009.

State Legislative Initiatives

House Bill 2813 ("HB 2813") was signed into law in May 2008, at which time it became effective. HB 2813 was created in order to advance the development of Oklahoma's vast wind power potential. This law provides for additional financial certainty for transmission line projects deemed necessary for the development of wind energy. The costs associated with such transmission lines are to be presumed to be recoverable if the lines are in service within five years of the passage of the law and meet the necessary criteria. OG&E has announced its intentions to build transmission lines and substantially increase the amount of generation it produces by wind, and management believes that this legislation increases the likelihood of recovering the costs associated with the construction of transmission lines.

House Bill 1739 ("HB 1739") was signed into law in May 2008, with an effective date of January 1, 2009. HB 1739 creates a system whereby utilities can divide their territories with the proper government oversight. The bill only relates to new customers in the territory and does not allow switching of existing customers. The law also codifies the right of investor-owned utilities to be able to continue serving in annexed territories of cities with municipal electric systems, where they can demonstrate a prior right to be in the annexed territory. The law is retroactive to include previous annexations as well as those that may occur in the future. This law also clarifies which utilities can serve in a territory annexed by a city because duplication of infrastructure has caused problems over the years since it possesses a potential safety hazard to line workers.

The benefits of this law to OG&E include being able to reduce future duplication of power lines and other infrastructure as well as clearly establishing the right to serve in areas previously considered legally questionable by certain parties.

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.

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, 2008 and 2007, 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, 2008. 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, 2008 and 2007, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2008, 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, 2008, 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 11, 2009 expressed an unqualified opinion thereon.

As discussed in Notes 6 and 9 to the consolidated financial statements, 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 11, 2009

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*)		March 31	June 30	September 30	December 31	Total
Operating revenues	**2008**	**$ 994.7**	**$ 1,135.7**	**$ 1,254.3**	**$ 686.0**	**$ 4,070.7**
	2007	881.5	913.4	1,044.5	958.2	3,797.6
Operating income	**2008**	**$ 48.1**	**$ 122.7**	**$ 231.2**	**$ 60.1**	**$ 462.1**
	2007	46.2	117.2	218.3	73.6	455.3
Net income	**2008**	**$ 13.0**	**$ 57.1**	**$ 139.5**	**$ 21.8**	**$ 231.4**
	2007	17.2	62.6	126.8	37.6	244.2
Basic earnings per average common share	**2008**	**$ 0.14**	**$ 0.62**	**$ 1.51**	**$ 0.23**	**$ 2.50**
	2007	0.19	0.68	1.38	0.41	2.66
Diluted earnings per average common share	**2008**	**$ 0.14**	**$ 0.62**	**$ 1.50**	**$ 0.23**	**$ 2.49**
	2007	0.19	0.68	1.37	0.40	2.64

Dividends

COMMON STOCK

- Common quarterly dividends paid (as declared) in 2008 were $0.3475 each for the first three quarters of 2008 and was $0.3550 for the fourth quarter of 2008. 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 $0.3325 each for the first three quarters of 2006 and was $0.34 for the fourth quarter of 2006.
- Present rate – $0.3550
- 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, 2008. 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, 2008, 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
Peter B. Delaney, Chairman of the Board, President
and Chief Executive Officer

/s/ Danny P. Harris
Danny P. Harris, Senior Vice President
and Chief Officer

/s/ Scott Forbes
Scott Forbes, Controller, Chief Accounting Officer
and Interim Chief Financial 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, 2008, 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, 2008, 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, 2008 and 2007, 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, 2008 of OGE Energy Corp. and our report dated February 11, 2009 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 11, 2009

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.

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) 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, 2009. 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, 2008 and 2007
- Consolidated Statements of Capitalization at December 31, 2008 and 2007
- Consolidated Statements of Income for the years ended December 31, 2008, 2007 and 2006
- Consolidated Statements of Changes in Stockholders' Equity for the years ended December 31, 2008, 2007 and 2006
- Consolidated Statements of Cash Flows for the years ended December 31, 2008, 2007 and 2006
- 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

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

3. Exhibits

Exhibit No.	Description
2.01	Purchase Agreement, dated as of May 14, 1999, by and between Tejas Gas, LLC and Enogex Inc. (Filed as Exhibit 2.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 1999 (File No. 1-12579) and incorporated by reference herein)
2.02	Asset Purchase Agreement, dated as of August 18, 2003 by and between OG&E and NRG McClain LLC. (Certain exhibits and schedules were omitted and registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K 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 OGE Energy'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 OGE Energy'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 OGE Energy's Form 8-K filed January 25, 2008 (File No. 1-12579) and incorporated by reference herein)
2.17	Contribution Agreement dated as of September 22, 2008 between OGE Energy Corp. and Energy Transfer Partners, L.P. (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed September 26, 2008 (File No. 1-12579) and incorporated by reference herein) (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)
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)
4.12	Supplemental Indenture No. 9 dated as of September 1, 2008 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed September 9, 2008 (File No. 1-1097) and incorporated by reference herein)
4.13	Supplemental Indenture No. 10 dated as of December 1, 2008 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed December 11, 2008 (File No. 1-1097) and incorporated by reference herein)
10.01*	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)
10.02*	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)
10.03*	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)
10.04	Copy of Amended and Restated Rights Agreement, dated as of October 10, 2000 between OGE Energy Corp. and Chase Mellon Shareholder Services, LLC (now BNY Mellon Shareowner Services), 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)
10.05	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)
10.06	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)
10.07	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)

10.08	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)
10.09*	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)
10.10	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)
10.11	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)
10.12*	Form of Performance Unit Agreement under 2008 Stock Incentive Plan.
10.13*	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)
10.14	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 OGE Energy's Form 8-K filed December 12, 2006 (File No. 1-12579) and incorporated by reference herein)
10.15	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 OGE Energy's Form 8-K filed December 12, 2006 (File No. 1-12579) and incorporated by reference herein)
10.16*	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)
10.17*	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)
10.18	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)
10.19*	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)
10.20	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 OGE Energy's Form 8-K filed January 25, 2008 (File No. 1-12579) and incorporated by reference herein)
10.21*	Amendment No. 1 to OGE Energy Corp. Employees' Stock Ownership and Retirement Savings Plan, as amended and restated. (Filed as Exhibit 10.33 to OGE Energy's Form 10-K for the year ended December 31, 2007 (File No. 1-12579) and incorporated by reference herein)

10.22*	Amendment No. 2 to OGE Energy Corp. Employees' Stock Ownership and Retirement Savings Plan, as amended and restated. (Filed as Exhibit 10.34 to OGE Energy's Form 10-K for the year ended December 31, 2007 (File No. 1-12579) and incorporated by reference herein)
10.23	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. (Filed as Exhibit 10.35 to OGE Energy's Form 10-K for the year ended December 31, 2007 (File No. 1-12579) and incorporated by reference herein)
10.24	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. (Filed as Exhibit 10.36 to OGE Energy's Form 10-K for the year ended December 31, 2007 (File No. 1-12579) and incorporated by reference herein)
10.25	Credit Agreement dated as of April 1, 2008, by and among Enogex LLC, the Lenders thereto, Wachovia Bank, National Association, as Administrative Agent, The Royal Bank of Scotland plc, as Syndication Agent, and JPMorgan Chase Bank, N.A, Mizuho Corporate Bank, LTD. and Union Bank of California, as Co-Documentation Agents. (Filed as Exhibit 10.01 to OGE Energy's Form 8-K filed April 7, 2008 (File No. 1-12579) and incorporated by reference herein)
10.26*	Amendment No. 1 to the Company's 2003 Annual Incentive Compensation Plan. (Filed as Exhibit 10.02 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.27*	OGE Energy Corp. Supplemental Executive Retirement Plan, as amended and restated. (Filed as Exhibit 10.03 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.28*	OGE Energy Corp. Restoration of Retirement Income Plan, as amended and restated. (Filed as Exhibit 10.04 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.29*	OGE Energy Corp. Deferred Compensation Plan, as amended and restated. (Filed as Exhibit 10.05 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.30*	Amendment No. 3 to the Company's 2003 Stock Incentive Plan. (Filed as Exhibit 10.06 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.31*	Amendment No. 2 to the Company's 1998 Stock Incentive Plan. (Filed as Exhibit 10.07 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.32*	The Company's 2008 Stock Incentive Plan. (Filed as Annex A to OGE Energy's Proxy Statement for the 2008 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)
10.33*	The Company's 2008 Annual Incentive Compensation Plan. (Filed as Annex B to OGE Energy's Proxy Statement for the 2008 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)
10.34*	Amendment No. 3 to OGE Energy Corp. Employees' Stock Ownership and Retirement Savings Plan, as amended and restated. (Filed as Exhibit 10.04 to OGE Energy's Form 10-Q for the quarter ended June 30, 2008 (File No. 1-12579) and incorporated by reference herein)
10.35*	Form of Amended and Restated Change of Control Agreement with current officers of the Company. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2008 (File No. 1-12579) and incorporated by reference herein)
10.36*	Amended and Restated Change of Control Agreement with Peter B. Delaney. (Filed as Exhibit 10.02 to OGE Energy's Form 10-Q for the quarter ended June 30, 2008 (File No. 1-12579) and incorporated by reference herein)

10.37*	Form of Change of Control Agreement with future officers of the Company. (Filed as Exhibit 10.03 to OGE Energy's Form 10-Q for the quarter ended June 30, 2008 (File No. 1-12579) and incorporated by reference herein)
10.38*	Form of Restricted Stock Agreement under 2008 Stock Incentive Plan. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended September 30, 2008 (File No. 1-12579) and incorporated by reference herein)
10.39*	Directors' Compensation.
10.40*	Executive Officer Compensation.
10.41	Distribution Agreement, dated as of November 20, 2008, by and between OGE Energy Corp. and J.P. Morgan Securities Inc. (Filed as Exhibit 1.01 to OGE Energy's Form 8-K filed November 20, 2008 (File No. 1-12579) and incorporated by reference herein)
10.42	Term Loan Agreement dated as of September 26, 2008 by and between Oklahoma Gas and Electric Company, UBS AG, as Administrative Agent, and UBS Securities LLC, as Sole Arranger and as Syndication Agent. (Filed as Exhibit 10.01 to OGE Energy's Form 8-K filed October 2, 2008 (File No. 1-12579) and incorporated by reference herein)
10.43	Term Loan Agreement dated as of September 26, 2008 by and between Oklahoma Gas and Electric Company and Royal Bank of Scotland PLC, as Administrative Agent and as Syndication Agent. (Filed as Exhibit 10.02 to OGE Energy's Form 8-K filed October 2, 2008 (File No. 1-12579) and incorporated by reference herein)
12.01	Calculation of Ratio of Earnings to Fixed Charges.
18.01	Letter from Ernst & Young LLP related to a change in accounting principle. (Filed as Exhibit 18.01 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
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)

* Represents executive compensation plans and arrangements.

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, 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
Year Ended December 31, 2008					
Reserve for Uncollectible Accounts	$ 3.8	$ 5.0	$ ---	$ 5.6 (A)	$ 3.2

(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 13th day of February, 2009.

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 13, 2009
/ s / Scott Forbes Scott Forbes	Principal Financial Officer and Principal Accounting Officer	February 13, 2009
Wayne H. Brunetti	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; and	
J. D. Williams	Director.	
/ s / Peter B. Delaney By Peter B. Delaney (attorney-in-fact)		February 13, 2009

Exhibit 10.12

OGE ENERGY CORP.
FORM OF PERFORMANCE UNIT AGREEMENT
UNDER 2008 STOCK INCENTIVE PLAN

OGE Energy Corp. (the "Company") hereby awards, at target, to (____) (the "Participant") (#) Performance Units pursuant to the OGE Energy Corp. 2008 Stock Incentive Plan (the "Plan"), the definitions and provisions of which are incorporated herein by reference.

The specific terms and conditions of the award are set forth hereinafter.

1. Performance Units and Award Cycle. Each Performance Unit represents and is equal to the value of one share of Company Common Stock. Subject to the provisions of the Plan, the Performance Units awarded to the Participant may not be sold, assigned, transferred, pledged, hypothecated or otherwise encumbered or disposed of during the award cycle established with respect thereto beginning on _________ and ending on _________ (the "Award Cycle").

2. Performance Goal Condition. The Performance Units are contingently awarded subject to the condition that the number of Performance Units, if any, earned by the Participant upon the expiration of the Award Cycle is dependent (in the manner hereinafter set forth) on the performance of Company's total shareholder return relative to the total shareholder return of all of the companies (the "S&P Companies") comprising the Standard and Poor's Utilities Index as of January 1, 2009 (or their successors from a merger or other combination with another company listed in such Index). Total shareholder return ("TSR") for any company, including the Company, shall include both price appreciation (depreciation) and cash dividends, shall be calculated in the same manner that Standard and Poor's calculated total return as of _________ and shall be measured by the Company's total return that shareholders receive over the Award Cycle by investment at the first day of the Award Cycle.

   The number of Performance Units earned is dependent on the performance ranking of the Company's total shareholder return for the Award Cycle, as set forth below (expressed in terms of the Company's position among the S&P Companies when ranked by total shareholder return for the Award Cycle):

COMPANY TSR PERCENTILE RANKING VS. S&P COMPANIES	**PERCENT OF TARGET PERFORMANCE UNITS EARNED**
__th percentile	200%
__th percentile	175%
__th percentile	150%
__th percentile	125%
__th percentile	100%
__th percentile	75%
__th percentile	50%
__th percentile	25%
Below __th percentile	0%

   Performance Units earned for performance between the percentiles shown above will be determined by straight-line interpolation; provided, that, in all cases, the number of Performance Units which the Participant earns shall be a whole number (disregarding any fraction).

   Any Performance Units awarded hereunder that the Participant does not earn at the end of the Award Cycle pursuant to the foregoing schedule shall be forfeited.

   The provisions of this Section 2 shall not affect in any way any forfeiture under Section 4 below or Section 8(b) of the Plan or any provision regarding the earning of Performance Units at the 100% target level under Section 9 of the Plan upon the occurrence of a Change of Control.

3. Payout. Subject to Section 9 of the Plan, as soon as practicable following the end of the Award Cycle, but in no event later than the 15th day of the third month thereafter, the Committee shall determine and certify to the number of Performance Units earned hereunder and, after the Committee certifies in writing the number of Performance Units earned and that all other material terms of the award have been satisfied, earned Performance Units, if any,

will be paid to the Participant, or on the Participant's death, to the Participant's beneficiary under the Plan, by issuing a certificate for shares of Common Stock equal in number to the earned Performance Units (disregarding any fraction).

4. Forfeiture. All Performance Unit awards are subject to the terms and conditions of the Plan relating to Performance Units. If the Participant incurs a Termination of Employment for any reason on or before the end of the Award Cycle, all rights to or in respect of Performance Units awarded hereunder shall be forfeited except as provided in Section 8(b)(iii) or Section 9(a)(iii) of the Plan.

5. Acceptance of Award. By execution of this Agreement, the Participant accepts the award, acknowledges receipt of a copy of the Plan (a copy of which is attached as Annex I), and represents that the Participant is familiar with the terms and provisions thereof and agrees to be bound thereby. Participant further agrees to accept as binding, conclusive and final all decisions or interpretations of the Committee with respect to any questions arising under the Plan, including any calculation of, or in connection with, the total shareholder return of the Company or any other company for the Award Cycle.

6. Taxes and Other Matters.

(a) By execution of this Agreement, the Participant agrees to pay all withholding and other taxes payable by the Participant with respect to Performance Units earned under this Agreement at such times and in such manner as the Company may request, and the Participant further agrees to comply with all Federal and State securities laws.

(b) The Participant may elect, subject to approval of the Board of Directors or a committee composed of two or more non-employee directors within the meaning of Rule 16b-3(b)(3) of the Securities Exchange Act of 1934 or any successor provision thereto, to satisfy Participant's minimum tax withholding requirements under Federal, State and local laws and regulations thereunder, in whole or in part, by having the Company withhold shares having a fair market value equal to all or a portion of the amount so required to be withheld. The value of the shares to be withheld is to be based upon the same price of the shares that is utilized to determine the amount of withholding tax that the Participant owes. All elections under this Section 6(b) shall be (i) irrevocable, (ii) made in writing and signed by the Participant on the form prescribed by the Company and (iii) submitted to the Board of Directors prior to the date on which the Committee will determine the number of Performance Units earned hereunder or such earlier date as the Company shall prescribe.

7. Other Condition. The award of Performance Units evidenced by this Agreement shall be subject to delivery to the Company of an executed copy of this Agreement.

OGE ENERGY CORP.

By: ____

Chairman of the Board, President and Chief Executive Officer

ACCEPTED AND AGREED TO this _____ day of _______.

____

Participant

OGE ENERGY CORP.
PERFORMANCE UNIT AGREEMENT

OGE Energy Corp. (the "Company") hereby awards, at target, to (______) (the "Participant") Performance Units pursuant to the OGE Energy Corp. 2008 Stock Incentive Plan (the "Plan"), the definitions and provisions of which are incorporated herein by reference.

The specific terms and conditions of the award are set forth hereinafter.

1. Performance Units and Award Cycle. Each Performance Unit represents and is equal to the value of one share of Company Common Stock. Subject to the provisions of the Plan, the Performance Units awarded to the Participant may not be sold, assigned, transferred, pledged, hypothecated or otherwise encumbered or disposed of during the award cycle established with respect thereto beginning on _________ and ending on _________ (the "Award Cycle").

2. Performance Goal Condition. The Performance Units are contingently awarded subject to the condition that the number of Performance Units, if any, earned by the Participant upon the expiration of the Award Cycle is dependent (in the manner hereinafter set forth) on the Company's Average Earnings Per Share Growth during the Award Cycle. Average Earnings Per Share Growth shall mean the amount obtained by multiplying one-third times the percentage increase or decrease in the Company's earnings per share for the year ended December 31, 2011 as compared to the Company's earnings per share for the year ended December 31, _____, of $_____. Thus, for example, if the Company's earnings per share were $_____ for the year ended December 31, ____, the Company's Average Earnings Per Share Growth would be _____% [1/3 x ($_____)]. For purposes of the foregoing, all percentages shall be calculated to the nearest one-hundredth of one percent and the Company's earnings per share for any year shall be the consolidated diluted earnings per average common share of the Company as reported on the Company's Consolidated Statement of Income for such year. The number of Performance Units earned for the Award Cycle shall be determined in accordance with the following chart:

COMPANY'S AVERAGE EARNINGS PER SHARE GROWTH	PERCENT OF TARGET PERFORMANCE UNITS EARNED
_____%	200%
_____%	175%
_____%	150%
_____%	125%
_____%	100%
_____%	75%
_____%	50%
Below _____%	0%

Performance Units earned for performance between the percentiles shown above will be determined by straight-line interpolation; provided, that, in all cases, the number of Performance Units which the Participant earns shall be a whole number (disregarding any fraction).

Any Performance Units awarded hereunder that the Participant does not earn at the end of the Award Cycle pursuant to the foregoing chart shall be forfeited.

The provisions of this Section 2 shall not affect in any way any forfeiture under Section 4 below or Section 8(b) of the Plan or any provision regarding the earning of Performance Units at the 100% target level under Section 9 of the Plan upon the occurrence of a Change of Control.

3. Payout. Subject to Section 9 of the Plan, as soon as practicable following the end of the Award Cycle, but in no event later than the 15th day of the third month thereafter, the Committee shall determine and certify to the number of Performance Units earned hereunder and, after the Committee certifies in writing the number of Performance Units earned and that other material terms of the award have been satisfied, earned Performance Units, if any, will be paid to the Participant, or on the Participant's death, to the Participant's beneficiary under the Plan, by issuing a certificate for shares of Common Stock equal in number to the earned Performance Units (disregarding any fraction).

4. Forfeiture. All Performance Unit awards are subject to the terms and conditions of the Plan relating to Performance Units. If the Participant incurs a Termination of Employment for any reason on or before the end of the Award Cycle, all rights to or in respect of Performance Units awarded hereunder shall be forfeited except as provided in Section 8(b)(iii) or Section 9(a)(iii) of the Plan.

5. Acceptance of Award. By execution of this Agreement, the Participant accepts the award, acknowledges receipt of a copy of the Plan (a copy of which is attached as Annex I), and represents that the Participant is familiar with the terms and provisions thereof and agrees to be bound thereby. Participant further agrees to accept as binding, conclusive and final all decisions or interpretations of the Committee with respect to any questions arising under the Plan, including any calculation of, or in connection with, earnings per share of the Company or any other company for the any period.

6. Taxes and Other Matters.

(a) By execution of this Agreement, the Participant agrees to pay all withholding and other taxes payable by the Participant with respect to Performance Units earned under this Agreement at such times and in such manner as the Company may request, and the Participant further agrees to comply with all Federal and State securities laws.

(b) The Participant may elect, subject to approval of the Board of Directors or a committee composed of two or more non-employee directors within the meaning of Rule 16b-3(b)(3) of the Securities Exchange Act of 1934 or any successor provision thereto, to satisfy Participant's minimum tax withholding requirements under Federal, State and local laws and regulations thereunder, in whole or in part, by having the Company withhold shares having a fair market value equal to all or a portion of the amount so required to be withheld. The value of the shares to be withheld is to be based upon the same price of the shares that is utilized to determine the amount of withholding tax that the Participant owes. All elections under this Section 6(b) shall be (i) irrevocable, (ii) made in writing and signed by the Participant on the form prescribed by the Company and (iii) submitted to the Board of Directors prior to the date on which the Committee will determine the number of Performance Units earned hereunder or such earlier date as the Company shall prescribe.

7. Other Condition. The award of Performance Units evidenced by this Agreement shall be subject to delivery to the Company of an executed copy of this Agreement.

OGE ENERGY CORP.

By: ____
Chairman of the Board, President and Chief Executive Officer

ACCEPTED AND AGREED TO this _____ day of _______.

____
Participant

Exhibit 10.39

OGE ENERGY CORP.
DIRECTORS' COMPENSATION

Compensation of non-officer directors of the Company during 2008 included an annual retainer fee of $91,000, of which $2,917 was payable monthly in cash and $56,000 was deposited in the director's account under the Company's Deferred Compensation Plan in December 2008 and converted to 2,362.869 common stock units based on the closing price of the Company's Common Stock on December 1, 2008. 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 2008. 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 2008.

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 2008, 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 December 2008, the compensation committee met to consider director compensation. At that meeting, the compensation committee approved the compensation described above.

Historically, for those directors who retired from the Board of Directors after ten 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.

OGE ENERGY CORP.
EXECUTIVE OFFICER COMPENSATION

Executive Compensation

In December 2008, 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 2009. 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 2009 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 2009 for the current OGE Energy officers who are expected to be named in the Summary Compensation Table in OGE Energy's 2009 Proxy Statement (the "Named Executive Officers") are as follows:

Named Executive Officer	2009 Base Salary
Peter B. Delaney, Chairman and Chief Executive Officer	$775,000
Scott Forbes, Controller, Chief Accounting Officer and Interim Chief Financial Officer	$229,500
Danny P. Harris, Senior Vice President and Chief Operating Officer	$510,000
E. Keith Mitchell, Senior Vice President and Chief Operating Officer – Enogex LLC	$293,500
Paul L. Renfrow, Vice President, Public Affairs	$228,000

Establishment of 2009 Annual Incentive Awards

As stated above, at its December 2008 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 2009 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 2009, the targeted amount was 85 percent of salary for Mr. Delaney and ranged from 35 percent to 70 percent of salary for the other Named Executive Officers.

Establishment of Long-Term Awards

At its December 2008 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 2009, the targeted amount was 225 percent of salary for Mr. Delaney and ranged from 65 percent to 170 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 all 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 2008, 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 three 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, an annual physical exam and, in the case of Mr. Delaney, a leased car. 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. This type of provision is sometimes called a "modified double-trigger" because payment is made only if there is a change of control and the executive officer's employment is terminated. The agreements utilize a modified double-trigger because the Board of Directors believes change-of-control payments only should be made if there is a separation of employment following a change-of-control, but also believes that the right to voluntarily terminate for any reason within 30 days after the first anniversary of the change of control helps to ensure that the executive's services will be available during an important transition period. The 2.99 times multiple for change-of-control payments was selected because at the time it was considered standard. Although many companies also include provisions for tax gross-up payments to cover any excise taxes on excess parachute payments, the Board of Directors of the Company decided not to include this additional benefit in the Company's agreements. Instead, under the Company's agreements if an excise tax 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 Agreements are filed as Exhibits 10.35, 10.36 and 10.37 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 12.01

OGE ENERGY CORP.
RATIO OF EARNINGS TO FIXED CHARGES

(in thousands)	Year Ended Dec 31, 2004	Year Ended Dec 31, 2005	Year Ended Dec 31, 2006	Year Ended Dec 31, 2007	Year Ended Dec 31, 2008
Earnings:					
Pre-tax income from continuing operations	$ 215,289	$ 229,838	$ 346,560	$ 360,958	$ 332,594
Add Fixed Charges	95,978	95,957	104,156	97,599	130,023
Subtotal	311,267	325,795	450,716	458,557	462,617
Subtract:					
Allowance for borrowed funds used during construction	1,662	2,233	4,487	3,989	3,950
Other capitalized interest	---	---	920	902	3,615
Total Earnings	309,605	323,562	445,309	453,666	455,052
Fixed Charges:					
Interest on long-term debt	83,094	79,951	88,287	88,677	106,565
Interest on short-term debt and other interest charges	9,359	12,571	13,108	6,444	21,041
Calculated interest on leased property	3,525	3,435	2,761	2,478	2,417
Total Fixed Charges	$ 95,978	$ 95,957	$ 104,156	$ 97,599	$ 130,023
Ratio of Earnings to Fixed Charges	3.23	3.37	4.28	4.65	3.50

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Exhibit 21.01

OGE Energy Corp.
Subsidiaries of the Registrant

Name of Subsidiary	Jurisdiction of Incorporation	Percentage of Ownership
Oklahoma Gas and Electric Company	Oklahoma	100.0
Enogex LLC	Oklahoma	100.0
Enogex Products LLC	Oklahoma	100.0
Enogex Gas Gathering LLC	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-8 No. 333-152022) pertaining to the 2008 stock incentive plan, the Registration Statement (Form S-3ASR No. 333-151780) pertaining to common stock and preferred share purchase rights and the Registration Statement (Form S-3ASR No. 333-155756) pertaining to the dividend reinvestment and stock purchase plan, of our reports dated February 11, 2009, 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, 2008.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 11, 2009

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, 2008; 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 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 12th day of February, 2009.

Peter B. Delaney, Chairman, Principal Executive Officer and Director	/ s / Peter B. Delaney
Wayne H. Brunetti, Director	/ s / Wayne H. Brunetti
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
J. D. Williams, Director	/ s / J. D. Williams
Scott Forbes, Principal Financial Officer and 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 12th day of February, 2009.

/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 13, 2009

/s/ Peter B. Delaney

Peter B. Delaney
Chairman of the Board, President and
Chief Executive Officer

Exhibit 31.01

CERTIFICATIONS

I, Scott Forbes, 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 13, 2009

/s/ Scott Forbes

Scott Forbes
Controller, Chief Accounting Officer
and Interim 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, 2008, 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 13, 2009

/s/ Peter B. Delaney

Peter B. Delaney
Chairman of the Board, President
and Chief Executive Officer

/s/ Scott Forbes

Scott Forbes
Controller, Chief Accounting Officer
and Interim Chief Financial Officer

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, Natural Gas 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, access to existing lines 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 15 of Notes to Consolidated Financial Statements of the Company’s Form 10-K for the year ended December 31, 2008, 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; and

- Discontinuance of regulated accounting principles under SFAS No. 71.

Natural Gas Transportation and Storage and Natural Gas Gathering and Processing 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; and

- Cold weather extremes that may impact the ability of producing customers to maintain gas deliveries, or the quality of such deliveries, into the pipeline system.

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