UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)
S ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2011

OR

£ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____to_____

Commission File Number: 1-12579

OGE ENERGY CORP.
(Exact name of registrant as specified in its charter)

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

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

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

Title of each class	Name of each exchange on which registered
Common Stock	New York Stock Exchange

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. R Yes £ No

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

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. R Yes £ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). R Yes £ No

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. R

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 the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer R	Accelerated filer £
Non-accelerated filer £ (Do not check if a smaller reporting company)	Smaller reporting company £

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

At June 30, 2011, 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 $4,904,111,913 based on the number of shares held by non-affiliates (97,458,504) and the reported closing market price of the common stock on the New York Stock Exchange on such date of $50.32.

At January 31, 2012, there were 98,073,157 shares of common stock, par value $0.01 per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The Proxy Statement for the Company's 2012 annual meeting of shareowners is incorporated by reference into Part III of this Form 10-K.

OGE ENERGY CORP.

FORM 10-K

FOR THE YEAR ENDED DECEMBER 31, 2011

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GLOSSARY OF TERMS

The following is a glossary of frequently used abbreviations that are found throughout this Form 10-K.

Abbreviation	Definition
401(k) Plan	Qualified defined contribution retirement plan
APSC	Arkansas Public Service Commission
ArcLight group	Bronco Midstream Holdings, LLC, Bronco Midstream Holdings II, LLC, collectively
Atoka	Atoka Midstream LLC joint venture
BART	Best Available Retrofit Technology
Code	Internal Revenue Code of 1986
Company	OGE Energy, collectively with its subsidiaries
Cordillera	Cordillera Energy Partners III, LLC
Crossroads	OG&E's Crossroads wind farm in Dewey County, Oklahoma
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
Dry Scrubbers	Dry flue gas desulfurization units with Spray Dryer Absorber
Enogex	OGE Holdings, collectively with its subsidiaries
Enogex LLC	Enogex LLC, collectively with its subsidiaries
Enogex Holdings	Enogex Holdings LLC, the parent company of Enogex LLC and a majority-owned subsidiary of OGE Holdings
EPA	U.S. Environmental Protection Agency
Federal Clean Water Act	Federal Water Pollution Control Act of 1972, as amended
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States
MEP	Midcontinent Express Pipeline, LLC
MMBtu	Million British thermal unit
MMcf/d	Million cubic feet per day
MW	Megawatt
MWH	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NGLs	Natural gas liquids
NOX	Nitrogen oxide
NYMEX	New York Mercantile Exchange
OCC	Oklahoma Corporation Commission
ODEQ	Oklahoma Department of Environmental Quality
OER	OGE Energy Resources LLC, wholly-owned subsidiary of Enogex LLC
Off-system sales	Sales to other utilities and power marketers
OG&E	Oklahoma Gas and Electric Company
OGE Holdings	OGE Enogex Holdings, LLC, wholly-owned subsidiary of OGE Energy and parent company of Enogex Holdings
OSHA	Federal Occupational Safety and Health Act of 1970
Oxbow	Oxbow Midstream, LLC
Pension Plan	Qualified defined benefit retirement plan
PHMSA	U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration
PRM	Price risk management
Products	Enogex Products LLC, wholly-owned subsidiary of Enogex LLC
PSO	Public Service Company of Oklahoma
QF	Qualified cogeneration facilities
QF contracts	Contracts with QFs and small power production producers
SIP	State implementation plan
SO2	Sulfur dioxide
SPP	Southwest Power Pool
System sales	Sales to OG&E's customers
TBtu/d	Trillion British thermal units per day
Windspeed	OG&E's transmission line from Oklahoma City, Oklahoma to Woodward, Oklahoma

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 from those expressed in forward-looking statements. 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, access to the commercial paper markets, actions of rating agencies and their impact on capital expenditures;
- the ability of the Company and its subsidiaries to access the capital markets and obtain financing on favorable terms;
- prices and availability of electricity, coal, natural gas and NGLs, each on a stand-alone basis and in relation to each other as well as the processing contract mix between percent-of-liquids, percent-of-proceeds, keep-whole and fixed-fee;
- 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 accounting principles for certain types of rate-regulated activities;
- whether OG&E can successfully implement its Smart Grid program to install meters for its customers and integrate the Smart Grid meters with its customer billing and other computer information systems;
- the cost of protecting assets against, or damage due to, terrorism or cyber attacks;
- advances in technology;
- creditworthiness of suppliers, customers and other contractual parties;
- the higher degree of risk associated with the Company's nonregulated business compared with the Company's regulated utility business; and
- other risk factors listed in the reports filed by the Company with the Securities and Exchange Commission including those listed in "Item 1A. Risk Factors" and in Exhibit 99.01 to this Form 10-K.

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.

PART I

Item 1. Business.

THE COMPANY

Introduction

The Company is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central United States. The Company conducts these activities through four business segments: (i) electric utility, (ii) natural gas transportation and storage, (iii) natural gas gathering and processing and (iv) natural gas marketing. For financial information regarding these segments, see Note 15 of Notes to Consolidated Financial Statements. The Company was incorporated in August 1995 in the state of Oklahoma and its principal executive offices are located at 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321; telephone 405-553-3000.

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through OG&E and are subject to regulation by the OCC, the APSC and the 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 natural gas business in 1928 and is no longer engaged in the natural gas distribution business.

Enogex is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting, storing and marketing natural gas. Most of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex's operations are organized into three business segments: (i) natural gas transportation and storage, (ii) natural gas gathering and processing and (iii) natural gas marketing. Enogex LLC is a Delaware single-member limited liability company. At December 31, 2011, the Company indirectly owns an 81.3 percent membership interest in Enogex Holdings, which in turn owns all of the membership interests in Enogex LLC.

Company Strategy

The Company's mission 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's corporate strategy is to continue to maintain its existing business mix and diversified asset position of its regulated electric utility business and unregulated natural gas midstream business while providing competitive energy products and services to customers primarily in the south central United States as well as seeking growth opportunities in both businesses. Additionally, the Company wants to achieve a premium valuation of its businesses relative to its peers, grow earnings per share with a stable earnings pattern, create a high performance culture and achieve desired outcomes with target stakeholders.

OG&E is focused on increased investment to preserve system reliability and meet load growth by adding and maintaining infrastructure equipment and replacing aging transmission and distribution systems. OG&E is focused on maintaining strong regulatory and legislative relationships for the long-term benefit of its customers. In an effort to encourage more efficient use of electricity, OG&E is also providing energy management solutions to its customers through the Smart Grid program that utilizes newer technology to improve operational and environmental performance and promote demand-side management programs. If these initiatives are successful, OG&E believes it may be able to defer the construction or acquisition of any incremental fossil fuel generation capacity until 2020. As the Smart Grid platform matures, OG&E anticipates providing new products and services to its customers. In addition, OG&E is also pursuing additional transmission-related opportunities within the SPP. OG&E is customer focused and strives to provide excellent customer service.

Enogex's business plan entails growing its businesses and providing attractive financial returns through efficient operations and effective commercial management of its assets, capturing growth opportunities through expansion projects, increased utilization of existing assets and through acquisitions in and around its footprint. In addition, Enogex is seeking to geographically diversify its gathering, processing and transportation businesses principally by expanding into other areas that are complementary with the Company's capabilities. Enogex expects to accomplish this diversification by undertaking organic growth projects and through acquisitions.

The Company's financial objectives include a long-term annual earnings growth rate of five to seven percent on a weather-normalized basis, maintaining a strong credit rating as well as increasing the dividend to meet the Company's dividend payout objectives. The Company's target payout ratio is to pay out dividends no more than 60 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 the Company's shareholder base, the Company's financial position, the Company's growth targets, the composition of the Company's assets and investment opportunities. The Company believes it can accomplish these financial objectives 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.

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 268 communities and their contiguous rural and suburban areas. At December 31, 2011, two other communities and two rural electric cooperatives in Oklahoma and western Arkansas purchased electricity from OG&E for resale. The service area covers 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 268 communities that OG&E serves, 242 are located in Oklahoma and 26 in Arkansas. OG&E derived 90 percent of its total electric operating revenues in 2011 from sales in Oklahoma and the remainder from sales in Arkansas.

OG&E's system control area peak demand in 2011 was 7,057 MWs on August 3, 2011. OG&E's load responsibility peak demand was 6,513 MWs on August 3, 2011. As reflected in the table below and in the operating statistics that follow, there were 28.5 million MWH system sales in 2011, 27.6 million MWH system sales in 2010 and 25.9 million MWH system sales in 2009. Variations in system sales for the three years are reflected in the following table:

Year ended December 31	**2011**	**2011 vs. 2010 Increase**	2010	2010 vs. 2009 Increase	2009
System sales - millions of MWHs	**28.5**	**3.3%**	27.6	6.6%	25.9

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.

OKLAHOMA GAS AND ELECTRIC COMPANY
CERTAIN OPERATING STATISTICS

Year ended December 31	**2011**	2010	2009
ELECTRIC ENERGY *(Millions of MWH)*			
Generation (exclusive of station use)	**26.7**	25.6	25.0
Purchased	**4.9**	4.7	3.9
Total generated and purchased	**31.6**	30.3	28.9
OG&E use, free service and losses	**(2.1)**	(2.2)	(2.0)
Electric energy sold	**29.5**	28.1	26.9
ELECTRIC ENERGY SOLD *(Millions of MWH)*			
Residential	**9.9**	9.6	8.7
Commercial	**6.9**	6.7	6.4
Industrial	**3.9**	3.8	3.6
Oilfield	**3.2**	3.1	2.9
Public authorities and street light	**3.2**	3.0	3.0
Sales for resale	**1.4**	1.4	1.3
System sales	**28.5**	27.6	25.9
Off-system sales	**1.0**	0.5	1.0
Total sales	**29.5**	28.1	26.9
ELECTRIC OPERATING REVENUES *(In millions)*			
Residential	**$ 943.5**	$ 894.8	$ 717.9
Commercial	**531.3**	521.0	439.8
Industrial	**216.0**	212.5	172.1
Oilfield	**165.1**	162.8	132.6
Public authorities and street light	**207.4**	200.8	167.7
Sales for resale	**65.3**	65.8	53.6
Provision for rate refund	**—**	—	(0.6)
System sales revenues	**2,128.6**	2,057.7	1,683.1
Off-system sales revenues	**36.2**	21.7	31.8
Other	**46.7**	30.5	36.3
Total operating revenues	**$ 2,211.5**	$ 2,109.9	$ 1,751.2
ACTUAL NUMBER OF ELECTRIC CUSTOMERS *(At end of period)*			
Residential	**675,806**	670,309	665,344
Commercial	**87,480**	86,496	85,537
Industrial	**2,991**	3,020	3,056
Oilfield	**6,451**	6,418	6,437
Public authorities and street light	**16,374**	16,264	16,124
Sales for resale	**44**	51	52
Total	**789,146**	782,558	776,550
AVERAGE RESIDENTIAL CUSTOMER SALES			
Average annual revenue	**$ 1,401.84**	$ 1,339.81	$ 1,083.50
Average annual use (kilowatt-hour)	**14,738**	14,304	13,197
Average price per kilowatt-hour (cents)	**$ 9.51**	$ 9.37	$ 8.21

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, transmission activities, short-term borrowing authorization and accounting practices are subject to the jurisdiction of the FERC. The Secretary of the U.S. Department of Energy has jurisdiction over some of OG&E's facilities and operations. In 2011, 89 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight 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 OGE Energy. The order required that, among other things, (i) OGE Energy permit the OCC access to the books and records of OGE Energy and its affiliates relating to transactions with OG&E, (ii) OGE Energy employ accounting and other procedures and controls to protect against subsidization of non-utility activities by OG&E's customers and (iii) OGE Energy 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 OGE Energy 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

OG&E Wholesale Agreement

On May 28, 2009, OG&E sent a termination notice to the Arkansas Valley Electric Cooperative that OG&E would terminate its wholesale power agreement to all points of delivery where OG&E sells or has sold power to the Arkansas Valley Electric Cooperative, effective November 30, 2011. In December 2010, OG&E and the Arkansas Valley Electric Cooperative entered into a new wholesale power agreement whereby OG&E will supply wholesale power to the Arkansas Valley Electric Cooperative through June 2015. On January 3, 2011, OG&E submitted this agreement to the FERC for approval. The FERC approved the new wholesale power agreement on March 2, 2011 and the new contract was effective May 1, 2011.

OG&E Crossroads Wind Farm

On July 29, 2010, OG&E received an order from the OCC authorizing OG&E to recover from Oklahoma customers the cost to construct Crossroads, with the rider being implemented as the individual turbines are placed in service. The Crossroads wind farm was fully in service in January 2012. As part of this project, on June 16, 2011, OG&E entered into an interconnection agreement with the SPP for Crossroads which allowed Crossroads to interconnect at 227.5 MWs.

OG&E 2010 Arkansas Rate Case Filing

On September 28, 2010, OG&E filed a rate case with the APSC requesting an annual rate increase of $17.7 million, to recover the cost of significant electric system expansions and upgrades, including high-voltage transmission lines, that have been completed since the last rate filing in August 2008, as well as increased operating costs. OG&E also sought recovery, through a rider, of the Arkansas jurisdictional portion of (i) costs associated with transmission upgrades and facilities that have been approved by the SPP in its regional planning processes and constructed by other non-OG&E transmission owners throughout the SPP that have been allocated to OG&E through the FERC-approved transmission rates and (ii) SPP administrative fees. On June 17, 2011, the APSC approved a settlement agreement among all parties to the case and OG&E implemented new electric rates effective June 20, 2011. Key items of the APSC order include: (i) the recovery of and a return on significant electric system expansions and upgrades, including high-voltage transmission lines, as well as increased operating costs, totaling $8.8 million annually; (ii) authorization for OG&E to recover the actual cost of third-party transmission charges and SPP administrative fees through a rider mechanism which will remain in effect until new rates are implemented after OG&E's next general rate case (the Arkansas jurisdictional portion of the combined costs was $1.0 million in 2011); and (iii) the deferral of certain expenses associated with a customer education program in an amount not to exceed $0.3 million per year for a maximum of two years.

OG&E SPP Cost Tracker

On October 7, 2010, OG&E filed an application with the OCC seeking recovery of the Oklahoma jurisdictional portion of (i) costs associated with transmission upgrades and facilities that have been approved by the SPP in its regional planning processes and constructed by other non-OG&E transmission owners throughout the SPP that have been allocated to OG&E through the FERC-approved transmission rates and (ii) SPP administrative fees. OG&E requested authorization to implement a cost tracker in order to recover from its retail customers the third-party project costs discussed above and to collect its administrative SPP cost assessment levied under Schedule 1A of the SPP open access transmission tariff, which is currently recovered in base rates. OG&E also requested authorization to establish a regulatory asset effective January 1, 2011 in order to give OG&E the opportunity to recover such costs that will be paid but not recovered until the cost tracker is made effective. On February 8, 2011, all parties signed a settlement agreement in this matter which would allow OG&E to recover the costs discussed in (i) above through a recovery rider effective January 1, 2011. OG&E recovered $5.1 million of incremental revenues in 2011 through the rider. Rather than including the costs of the SPP administrative fee assessment in the recovery rider, the stipulating parties agreed to allow OG&E to include the projected 2012 level of the SPP administrative fee assessment in its next Oklahoma rate case which was filed in August 2011. Pursuant to the settlement agreement in OG&E's 2011 Oklahoma general rate case filing, OG&E proposed that recovery in base rates for the costs of transmission projects it constructs and owns and that are authorized by the SPP in its regional planning processes should be limited to the Oklahoma retail jurisdictional share of the costs for such projects allocated to OG&E by the SPP. On March 28, 2011, the OCC issued an order in this matter approving the settlement agreement.

OG&E Fuel Adjustment Clause Review for Calendar Year 2009

On October 29, 2010, the OCC Staff filed an application for a public hearing to review and monitor OG&E's application of the 2009 fuel adjustment clause. On December 28, 2010, OG&E responded by filing the necessary information and documents to satisfy the OCC's minimum filing requirement rules. An intervenor representing a group of OG&E's industrial customers filed testimony on March 11, 2011 seeking a $15.5 million refund related to (i) a purported failure by OG&E to maximize the use of its coal-fired power plants and (ii) an inappropriate extension of the existing gas transportation and storage contract between OG&E and Enogex. OG&E filed rebuttal testimony on April 4, 2011 in opposition to the claims of the intervenor. On August 11, 2011, all parties to this case signed a settlement agreement in this matter, stating that (i) OG&E was prudent in its operations during 2009; (ii) a third party expert should be hired to evaluate OG&E's future gas transportation and storage needs and that OG&E should file a plan for meeting its future gas transportation and storage needs by mid-2012; and (iii) with respect to the existing gas transportation and storage contract with Enogex, OG&E will return $8.4 million to its customers in settlement for all periods under the contract through April 30, 2013. In August 2011, OG&E credited $4.9 million to its customers and will credit the remaining amount on a monthly basis through April 30, 2013. The OCC issued an order approving the settlement agreement on August 29, 2011.

OG&E Smart Grid Project

On December 17, 2010, OG&E filed an application with the APSC requesting pre-approval for system-wide deployment of smart grid technology and a recovery rider, including a credit for the Smart Grid grant awarded by the U.S. Department of Energy under the American Recovery and Reinvestment Act of 2009. On June 22, 2011, OG&E reached a settlement agreement with all the parties in this matter. OG&E and the other parties in this matter agreed to ask the APSC to approve the settlement agreement including the following: (i) pre-approval of system-wide deployment of smart grid technology in Arkansas and authorization for OG&E to begin recovering the prudently incurred costs of the Arkansas system-wide deployment of smart grid technology through a rider mechanism that will become effective in accordance with the order approving the settlement agreement; (ii) cost recovery through the rider would commence when all of the smart meters to be deployed in Arkansas are in service; (iii) OG&E guarantees that customers will receive certain operations and maintenance cost reductions resulting from the smart grid deployment as a credit to the recovery rider; and (iv) the stranded costs associated with OG&E's existing meters which are being replaced by smart meters will be accumulated in a regulatory asset and recovered in base rates beginning after an order is issued in OG&E's next general rate case. OG&E currently expects to spend $14 million, net of funds from the U.S. Department of Energy grant, in capital expenditures to implement smart grid in Arkansas pursuant to the settlement agreement. On August 3, 2011, the APSC issued an order in this matter approving the settlement agreement.

OG&E FERC Transmission Rate Incentive Filing

On February 18, 2011, OG&E submitted to the FERC a request seeking limited transmission rate incentives for five transmission projects. OG&E requested recovery of 100 percent of all prudently incurred construction work in progress in rate base for five 345 kilovolt Extra High Voltage transmission projects to be constructed and owned by OG&E within the SPP's region. OG&E also requested to recover 100 percent of all prudently incurred development and construction costs if the transmission projects are abandoned or cancelled, in whole or in part, for reasons beyond OG&E's control. On April 19, 2011, the FERC granted these incentives for the Sooner-Rose Hill, Sunnyside-Hugo and Balanced Portfolio 3E transmission projects discussed below.

OG&E Pension Tracker Modification Filing

On February 22, 2011, OG&E filed an application with the OCC requesting that OG&E's pension tracker be modified to include the difference between the level of retiree medical costs authorized in OG&E's last rate case and the current level of these expenses as a regulatory liability, effective January 1, 2011. On June 23, 2011, a settlement agreement was filed by parties in the case stating that the pension tracker should be modified as proposed by OG&E and that the level of retiree medical costs included in base rates will be reviewed and determined in OG&E's next rate case. On September 27, 2011, the OCC issued an order in this matter approving the settlement agreement.

OG&E Demand and Energy Efficiency Program Filing

To build on the success of its earlier programs and further promote energy efficiency and conservation for each class of OG&E customers, on March 15, 2011, OG&E filed an application with the APSC seeking approval of several programs, ranging from residential weatherization to commercial lighting. In seeking approval of these programs, OG&E also sought recovery of the program and related costs through a rider that would be added to customers' electric bills. On June 30, 2011, the APSC issued an order approving OG&E's energy efficiency plan for 2011 and approving OG&E's energy efficiency cost recovery rider for 2011. In Arkansas, OG&E's program is expected to cost $7.0 million over a three-year period and is expected to increase the average residential electric bill by $1.47 per month.

FERC Order No. 1000, Final Rule on Transmission Planning and Cost Allocation

On July 21, 2011, the FERC issued Order No. 1000, which revised the FERC's existing regulations governing the process for planning enhancements and expansions of the electric transmission grid in a particular region, along with the corresponding process for allocating the costs of such expansions. Order No. 1000 applies only to "new transmission facilities," which are described as those subject to evaluation or reevaluation (under the applicable local or regional transmission planning process) subsequent to the effective date of the regulatory compliance filings required by the rule, which are expected to be filed during the third quarter of 2012. Order No. 1000 leaves to individual regions to determine whether a previously-approved project is subject to reevaluation and is therefore governed by the new rule.

Order No. 1000 requires, among other things, public utility transmission providers, such as the SPP, to participate in a process that produces a regional transmission plan satisfying certain standards, and requires that each such regional process consider transmission needs driven by public policy requirements (such as state or Federal policies favoring increased use of renewable energy resources). Order No. 1000 also directs public utility transmission providers to coordinate with neighboring transmission planning regions. In addition, Order No. 1000 establishes specific regional cost allocation principles and directs public utility transmission providers to participate in regional and interregional transmission planning processes that satisfy these principles.

On the issue of determining how entities are to be selected to develop and construct the specific transmission projects, Order No. 1000 directs public utility transmission providers to remove from the FERC-jurisdictional tariffs and agreements provisions that establish any federal "right of first refusal" for the incumbent transmission owner (such as OG&E) regarding transmission facilities selected in a regional transmission planning process, subject to certain limitations. However, Order No. 1000 is not intended to affect the right of an incumbent transmission owner (such as OG&E) to build, own and recover costs for upgrades to its own transmission facilities, and Order No. 1000 does not alter an incumbent transmission owner's use and control of existing rights of way. Order No. 1000 also clarifies that incumbent transmission owners may rely on regional transmission facilities to meet their reliability needs or service obligations. The SPP currently has a "right of first refusal" for incumbent transmission owners and this provision has played a role in OG&E being selected by the SPP to build various transmission projects in Oklahoma.

OGE Energy is continuing to evaluate Order No. 1000 and cannot at this time determine its precise impact on OG&E. Nevertheless, at the present time, OGE Energy has no reason to believe that the implementation of Order No. 1000 will impact OG&E's transmission projects currently under development and construction for which OG&E has received a notice to proceed from the SPP.

Pending Regulatory Matters

OG&E 2011 Oklahoma Rate Case Filing

As part of the Joint Stipulation and Settlement Agreement reached in OG&E's 2009 Oklahoma rate case filing, the parties agreed that OG&E would file a rate case on or before June 30, 2011. On May 27, 2011, OG&E requested an extension until the end of July 2011 for filing the Oklahoma rate case. On July 28, 2011, OG&E filed its application with the OCC requesting an annual rate increase of $73.3 million, or a 4.3 percent increase in its rates. OG&E is requesting a return on equity of 11.00 percent based on a common equity percentage of 53 percent. Each 0.10 percent change in the requested return on equity affects the requested rate increase by $3.0 million. In its application, OG&E seeks to recover increases in its operating costs and to begin earning on approximately $500 million of new capital investments made on behalf of its Oklahoma customers during the previous two and one-half years. On November 9, 2011, the OCC Staff recommended a $6.2 million annual rate decrease based on a return on equity of 9.81 percent and a common equity percentage of 53 percent. The staff of the Oklahoma Attorney General recommended a return on equity of 9.818 percent and a common equity percentage of 49.5 percent. The staff of the Oklahoma Attorney General did not recommend a specific revenue requirement, but OG&E believes that adoption of the staff of the Oklahoma Attorney General's recommendations would result in a rate decrease. The Oklahoma Industrial Electric Consumers recommended a $56 million annual rate decrease based on a return on equity of 9.5 percent and a common equity percentage of 48 percent. OG&E filed rebuttal testimony on November 29, 2011 on the revenue requirement testimony filed by the parties on November 9, 2011. On November 16, 2011, the parties filed cost-of-service and rate design testimony and OG&E filed rebuttal testimony in those areas on December 2, 2011. The hearing in this matter began on December 13, 2011. OG&E expects to receive an order from the OCC in the first quarter of 2012.

OG&E Fuel Adjustment Clause Review for Calendar Year 2010

On August 19, 2011, the OCC Staff filed an application for a public hearing to review and monitor OG&E's application of the 2010 fuel adjustment clause. On October 18, 2011, OG&E responded by filing the necessary information and documents to satisfy the OCC's minimum filing requirement rules. A procedural schedule has not yet been established in this matter.

OG&E Contract and Wind Energy Purchase Agreement Filing

On December 1, 2011, OG&E filed an application with the OCC requesting approval of a 20-year agreement that is intended to provide wind power to help meet the current and future power generation needs of Oklahoma State University. The project calls for OG&E to contract with NextEra Energy to build a 60 MW wind farm near Blackwell, Oklahoma, to support the Oklahoma State University project in which NextEra will build, own and operate the wind farm and OG&E will purchase the electric output. A procedural schedule has not yet been established in this matter. OG&E expects to receive a decision from the OCC in the first quarter of 2012.

SPP Transmission/Substation Projects

The SPP is a regional transmission organization under the jurisdiction of the FERC that was created to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale prices of electricity. The SPP does not build transmission though the SPP's tariff contains rules that govern the transmission construction process. Transmission owners complete the construction and then own, operate and maintain transmission assets within the SPP region. When the SPP Board of Directors approves a project, the transmission provider in the area where the project is needed currently has the first obligation to build; however, the process for deciding which entity constructs and owns a project may change as a result of FERC Order. No. 1000 discussed above.

There are several studies currently under review at the SPP including a 20-year plan to address issues of regional and interregional importance. The 20-year plan suggests overlaying the SPP footprint with a 345 kilovolt transmission system and integrating it with neighboring regional entities. In 2009, the SPP Board of Directors approved a new report that recommended restructuring the SPP's regional planning processes to focus on the construction of a robust transmission system, large enough in both scale and geography, to provide flexibility to meet the SPP's future needs. OG&E expects to actively participate in the ongoing study, development and transmission growth that may result from the SPP's plans.

In 2007, the SPP notified OG&E to construct 44 miles of a new 345 kilovolt transmission line which will originate at OG&E's existing Sooner 345 kilovolt substation and proceed generally in a northerly direction to the Oklahoma/Kansas Stateline (referred to as the Sooner-Rose Hill project). At the Oklahoma/Kansas Stateline, the line will connect to the companion line being constructed in Kansas by Westar Energy. Construction of the line began in early 2011 and the line is estimated to be in service by mid-2012 at an estimated cost of $45 million for OG&E.

In January 2009, OG&E received notification from the SPP to begin construction on 50 miles of a new 345 kilovolt transmission line and substation upgrades at OG&E's Sunnyside substation, among other projects. In April 2009, Western Farmers Electric Cooperative assigned to OG&E the construction of 50 miles of line designated by the SPP to be built by Western Farmers Electric Cooperative. The new line will extend from OG&E's Sunnyside substation near Ardmore, Oklahoma, 123.5 miles to the Hugo substation owned by Western Farmers Electric Cooperative near Hugo, Oklahoma. The project cost is estimated at $155 million for OG&E. OG&E began preliminary line routing and acquisition of rights-of-way in June 2009. Construction began in January 2011. When construction is completed, which is expected in mid-2012, the SPP will allocate a portion of the annual revenue requirement to OG&E customers according to the regional cost allocation mechanism as provided in the SPP tariff for application to such improvements.

On April 28, 2009, the SPP approved the Balanced Portfolio 3E projects. Balanced Portfolio 3E includes four projects to be built by OG&E and includes: (i) construction of 135 miles of transmission line from OG&E's Seminole substation in a northeastern direction to OG&E's Muskogee substation at an estimated cost of $160 million for OG&E, which is expected to be in service by late 2013, (ii) construction of 96 miles of transmission line from OG&E's Woodward District Extra High Voltage substation in a southwestern direction to the Oklahoma/Texas Stateline to a companion transmission line to be built by Southwestern Public Service to its Tuco substation at an estimated cost of $145 million for OG&E, which is expected to be in service by mid-2014, (iii) construction of 39 miles of transmission line from OG&E's Sooner substation in an eastern direction to the Grand River Dam Authority Cleveland substation at an estimated cost of $60 million for OG&E, which is expected to be in service by late 2012 and (iv) construction of a new substation near Anadarko which consisted of a 345/138 kilovolt transformer and substation breakers and was built in OG&E's portion of the Cimarron-Lawton East Side 345 kilovolt line at an estimated cost of $15 million for OG&E, which was placed in service in December 2011. On June 19, 2009, OG&E received a notice to construct the Balanced Portfolio 3E projects from the SPP. On July 23, 2009, OG&E responded to the SPP that OG&E will construct the Balanced Portfolio 3E projects discussed above beginning in early 2011.

On April 27, 2010, the SPP approved, contingent upon approval by the FERC of a regional cost allocation methodology filed with the FERC by the SPP, a set of transmission projects titled "Priority Projects." The Priority Projects consist of several transmission projects, two of which have been assigned to OG&E. The 345 kilovolt projects include: (i) construction of 99 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to a companion transmission line to be built by Southwestern Public Service to its Hitchland substation in the Texas Panhandle at an estimated cost of $185 million for OG&E, which is expected to be in service by mid-2014 and (ii) construction of 77 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to a companion transmission line at the Kansas border to be built by either Mid-Kansas Electric Company or another company assigned by Mid-Kansas Electric Company at an estimated cost of $150 million to OG&E, which is expected to be in service by late 2014. On June 17, 2010, the FERC approved the cost allocation filed by the SPP and notices to construct these Priority Projects were issued by the SPP on June 30, 2010. On September 27, 2010, OG&E responded to the SPP that OG&E will construct the Priority Projects discussed above beginning in June 2012. The scope of the Woodward District Extra High Voltage substation/Kansas border Priority Project was subsequently revised and the SPP Board of Directors approved this revision in October 2010. The SPP issued a revised notice to construct for this Priority Project on November 22, 2010. On February 4, 2011, OG&E responded to the SPP that OG&E will construct the revised Priority Project.

The capital expenditures related to the Sooner-Rose Hill, Sunnyside-Hugo, Balanced Portfolio 3E and Priority Projects are presented in the summary of capital expenditures for known and committed projects in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Future Capital Requirements and Financing Activities."

Regulatory Assets and Liabilities

OG&E, as a regulated utility, is subject to accounting principles for certain types of rate-regulated activities, which provide 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, 2011 and 2010, OG&E had regulatory assets of $523.9 million and $495.3 million, respectively, and regulatory liabilities of $276.4 million and $243.9 million, respectively. See Note 1 of Notes to Consolidated Financial Statements for a further discussion.

Management continuously monitors the future recoverability of regulatory assets. When in management's judgment future recovery becomes impaired, the amount of the regulatory asset is adjusted, as appropriate. If the Company were required to discontinue the application of accounting principles for certain types of rate-regulated activities for some or all of its operations, it could result in writing off the related regulatory assets, which could have significant financial effects.

Rate Structures

Oklahoma

OG&E's standard tariff rates include a cost-of-service component (including an authorized return on capital) plus a 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 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 guaranteed flat bill option. A second tariff rate option provides a "renewable energy" resource to OG&E's Oklahoma retail customers. This renewable energy resource is a Renewable Energy Credit 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 option a possible choice in meeting the renewable energy needs of our conservation-minded customers. Another program being offered to OG&E's commercial and industrial customers is a voluntary load curtailment program called Load Reduction. 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. OG&E also offers certain qualifying customers a "day-ahead price" rate option which allows participating customers to adjust their electricity consumption based on a price signal received from OG&E. The day-ahead price is based on OG&E's projected next day hourly operating costs.

OG&E also has two rate classes, Public Schools-Demand and Public Schools Non-Demand, that will provide OG&E with 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 implemented a military base rider that demonstrates Oklahoma's continued commitment to our military partners.

The previously discussed rate options, coupled with OG&E's other rate choices, provide many tariff options for OG&E's Oklahoma retail customers. 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. Revenue variations may occur in the future based upon changes in customers' usage characteristics if they choose alternative rate options. 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 OG&E's customers for many years to come.

Arkansas

OG&E's standard tariff rates include a cost-of service component (including an authorized return on capital) plus an energy cost recovery mechanism that allows OG&E to pass through to customers the actual cost of fuel. OG&E offers several alternate customer programs and rate options. The "time-of-use" and "variable peak pricing" tariffs allow participating customers to save on their electricity bills by shifting some of the electricity consumption to times when demand for electricity is lowest. A second tariff rate option provides a "renewable energy" resource to OG&E's Arkansas retail customers. This renewable energy resource is a Renewable Energy Credit purchase program and is available as a voluntary option to all of OG&E's Arkansas retail customers. OG&E's ownership and access to wind resources makes the renewable option a possible choice in meeting the renewable energy needs of our conservation-minded customers. OG&E offers its commercial and industrial customers a voluntary load curtailment program called Load Reduction. This program provides customers with the opportunity to curtail usage on a voluntary basis and receive a billing credit when OG&E's system conditions merit curtailment action. OG&E offers certain qualifying customers a "day-ahead price" rate option which allows participating customers to adjust their electricity consumption based on a price signal received from OG&E. The day-ahead price is based on OG&E's projected next day hourly operating costs.

Fuel Supply and Generation

In 2011, 57.9 percent of the OG&E-generated energy was produced by coal-fired units, 39.2 percent by natural gas-fired units and 2.9 percent by wind-powered units. Of OG&E's 6,790 total MW capability reflected in the table under Item 2. Properties, 3,825 MWs, or 56.3 percent, are from natural gas generation, 2,548 MWs, or 37.5 percent, are from coal generation and 417 MWs, or 6.2 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, was as follows:

Year ended December 31 *(In Kilowatt-Hour - cents)*	**2011**	2010	2009	2008	2007
Coal	**2.064**	1.911	1.747	1.153	1.143
Natural gas	**4.328**	4.638	3.696	8.455	6.872
Weighted average	**2.897**	3.012	2.474	3.337	3.173

The decrease in the weighted average cost of fuel in 2011 as compared to 2010 was primarily due to lower natural gas prices and lower natural gas generation. The increase in the weighted average cost of fuel in 2010 as compared to 2009 was primarily due to higher natural gas prices and increased natural gas generation. The decrease in the weighted average cost of fuel in 2009 as compared to 2008 was primarily due to decreased natural gas prices partially offset by increased coal transportation rates in 2009. 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. A portion of these fuel costs is included in the base rates to customers and differs for each jurisdiction. The portion of recoverable fuel costs that is not included in the base rates is recovered through OG&E's fuel adjustment clauses that are approved by the OCC, the APSC and the FERC.

Coal

All of OG&E's coal-fired units, with an aggregate capability of 2,548 MWs, are designed to burn low sulfur western sub-bituminous coal. OG&E purchases coal primarily under contracts expiring in years 2012 and 2015. In 2011, OG&E purchased 7.5 million tons of coal from various Wyoming suppliers. The combination of all coal has a weighted average sulfur content of 0.26 percent. Based upon the average sulfur content and EPA certified emission data, OG&E's coal units have an approximate emission rate of 0.5 lbs. of SO2 per MMBtu. As discussed, in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Environmental Laws and Regulations," emission limits are expected to become more stringent.

See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Environmental Laws and Regulations" for a discussion of environmental matters which may affect OG&E in the future, including its utilization of coal.

Natural Gas

OG&E has natural gas contracts for purchases from January 2012 through March 2012 that account for 26 percent of OG&E's projected 2012 natural gas requirements. Additional gas supplies to fulfill OG&E's remaining 2012 natural gas requirements will be acquired through additional requests for proposal in early to mid-2012, along with monthly and daily purchases, all of which are expected to be made at market prices.

OG&E utilizes a natural gas storage facility for storage services that allows OG&E to maximize the value of its generation assets. Storage services are provided by Enogex as part of Enogex's gas transportation and storage contract with OG&E. At December 31, 2011, OG&E had 2.9 million MMBtu's in natural gas storage valued at $10.7 million.

Wind

OG&E's current wind power portfolio includes: (i) the Centennial wind farm, (ii) the OU Spirit wind farm, (iii) the Crossroads wind farm, (iv) 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 that expires in 2018, (v) access to up to 150 MWs of electricity generated at a wind farm in Woodward County, Oklahoma from a 20-year contract OG&E entered into with CPV Keenan that expires in 2030 and (vi) access to up to 130 MWs of electricity generated at a wind farm in Woodward County, Oklahoma from a 20-year contract OG&E entered into with Edison Mission Energy that expires in 2030.

Safety and Health Regulation

OG&E 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. 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 OG&E's operations and that this information be provided to employees, state and local government authorities and citizens. OG&E believes that it is in material compliance with all applicable laws and regulations relating to worker safety and health.

NATURAL GAS MIDSTREAM OPERATIONS - ENOGEX

Overview

Enogex is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting, storing and marketing natural gas. Most of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex's operations are organized into three business segments: (i) natural gas transportation and storage, (ii) natural gas gathering and processing and (iii) natural gas marketing.

On October 5, 2010, OGE Energy entered into an investment agreement with the ArcLight group, pursuant to which the ArcLight group agreed to make an initial equity investment in Enogex Holdings, which in turn owns all of the membership interests in Enogex LLC, in an amount equal to $183,150,000 in exchange for a 9.9 percent membership interest in Enogex Holdings. As a result of this transaction, the ArcLight group acquired an indirect 9.9 percent interest in Enogex LLC and OGE Energy retained an indirect 90.1 percent interest in Enogex LLC. The investment agreement provides the ArcLight group the opportunity to increase its ownership interest by providing equity funding for capital expenditures associated with Enogex's business plan. The transaction closed on November 1, 2010. As a result of the investment agreement described above and subsequent contributions by the ArcLight group, at December 31, 2011, the Company indirectly owns an 81.3 percent membership interest in Enogex Holdings.

As part of the investment agreement, OGE Energy and the ArcLight group have agreed to indemnify each other for breaches of representations, warranties and covenants contained in the investment agreement, and, in the case of OGE Energy, for certain tax matters related to the Company, in each case subject to customary thresholds and survival periods.

Pursuant to the Enogex Holdings LLC Agreement, OGE Holdings' and the ArcLight group's rights to designate directors to the Board of Directors of Enogex Holdings will be determined by percentage ownership. OGE Holdings was initially entitled to designate three directors, and the ArcLight group was initially entitled to designate one director. As its ownership position increases, the ArcLight group will be entitled to increasing board representation. The ArcLight group will also be entitled, at various ownership thresholds, to certain special board approval rights with respect to certain significant actions taken by Enogex Holdings, as well as to appoint additional directors for Enogex Holdings.

Until the ArcLight group owns 50 percent of the equity of Enogex Holdings, the ArcLight group will fund capital contributions in an amount higher than its proportionate interest. If necessary, the ArcLight group will fund between 50 percent and 90 percent of required capital contributions during that period. The remainder of the required capital contributions (i.e., between 10 percent and 50 percent) will be funded by OGE Holdings. Prior to January 1, 2012, the per unit equity price paid equaled the initial price that had been paid by the ArcLight group under the investment agreement. Beginning January 1, 2012, the equity price per unit will be based on the equity value of Enogex Holdings. Subject to certain adjustments, including for material acquisitions, equity value will be calculated as 9.0 or 9.5 times trailing 12-month Earnings before Interest, Taxes, Depreciation and Amortization, depending on the ArcLight group's ownership interest and whether the project has already been identified by Enogex Holdings.

Pursuant to the Enogex Holdings LLC Agreement, Enogex Holdings will make minimum quarterly distributions equal to the amount of cash required to cover OGE Energy's anticipated tax liabilities plus $12.5 million, to be distributed in proportion to each member's percentage ownership interest.

Under the terms of the Enogex Holdings LLC Agreement, each member and its affiliates are prohibited from independently pursuing a transaction in which a portion of the relevant assets are located in a designated core operating area, subject to certain exceptions. In addition, each member and its affiliates are prohibited from independently pursuing a transaction in which a portion of the relevant assets are located in a designated area of mutual interest unless (i) in the case of the ArcLight group, the collective ownership interest of the ArcLight group is less than five percent, (ii) the transaction falls within a defined category of passive financial investments, (iii) the proposed transaction has been disapproved by Enogex Holdings or (iv) the fair market value of the assets located in the area of mutual interest constitutes less than 50 percent of the total fair market value of the assets involved in the transaction. A member permitted to pursue a transaction independently pursuant to the foregoing is not required to offer the assets associated with such transaction to Enogex Holdings.

Transportation and Storage

General

Enogex owns and operates approximately 2,250 miles of intrastate natural gas transportation pipelines in Oklahoma with 1.94 TBtu/d of average daily throughput in 2011. Enogex also owns and operates two underground natural gas storage facilities in Oklahoma operating at a combined working gas level of 24 billion cubic feet. Enogex provides fee-based firm and interruptible transportation services on both an intrastate basis and pursuant to Section 311 of the Natural Gas Policy Act on an interstate 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 intrastate firm contracts, 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 obligated to transport natural gas nominated by the shipper only 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 f rom firm transportation services and leased capacity. To the extent pipeline capacity is not needed for such firm transportation services and leased capacity, Enogex offers interruptible 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, Cana/Woodford Shale play and the Colony Wash play in western Oklahoma and the Granite Wash play in the Wheeler County, Texas area, which is located in the Texas Panhandle). At December 31, 2011, Enogex was connected to 13 third-party natural gas pipelines and had 62 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, Postrock KPC Pipeline, LLC, Ozark Gas Transmission, L.L.C., Gulf Crossings Pipeline Company LLC and MEP. Further, Enogex is connected to 33 end-user customers, including 15 natural gas-fired electric generation facilities in Oklahoma.

Enogex owns and operates two underground natural gas storage facilities in Oklahoma operating at a combined working gas level of 24 billion cubic feet with 650 MMcf/d of maximum withdrawal capacity and 650 MMcf/d of injection capacity. Enogex offers both fee-based firm and interruptible storage services. Storage services offered under Section 311 of the Natural Gas Policy Act are pursuant to terms and conditions specified in Enogex's Statement of Operating Conditions for gas storage and at market-based rates.

Enogex uses its storage assets to meet its contractual obligations under certain load following transportation and storage contracts, including its transportation agreement with OG&E. Enogex also periodically conducts an open season to solicit commitments for contracted storage capacity and deliverability to third parties.

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. The stated term of the OG&E contract expired April 30, 2009, but the contract remains 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, 2012, the contract will remain in effect at least through April 30, 2013. 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 natural gas-fired electric generation facilities to serve residential and commercial electricity requirements. In 2011, 2010 and 2009, revenues from Enogex's firm intrastate transportation and storage contracts were $130.7 million, $116.6 million and $116.8 million, respectively, of which $47.5 million in each year was attributed to OG&E and $15.3 million in each year was attributed to PSO. Revenues from Enogex's firm intrastate transportation and storage contracts represented 30 percent of Enogex's consolidated gross margin in 2011, 28 percent in 2010 and 33 percent in 2009.

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 Natural Gas Policy Act. Rates to provide such service must be "fair and equitable" under the Natural Gas Policy Act and are subject to review and approval by the FERC at least once every five years (previously a triennial requirement). The rate review may, but will not necessarily, involve an administrative-type hearing before a FERC Staff panel and an administrative appellate review. In the past, Enogex has successfully settled, rather than litigated, its Section 311 rate cases. Enogex currently has two zones under its Section 311 rate structure – an East Zone and a West Zone. Enogex historically offered only interruptible Section 311 service in both zones. Enogex began to offer firm Section 311 service in the East Zone on April 1, 2009 and in the West Zone on March 1, 2011.

For Section 311 service, Enogex may charge up to its maximum established zonal East and West interruptible transportation rates for interruptible transportation in one zone or cumulative maximum rates for transportation in both zones. Enogex may charge up to its maximum established firm rate for firm Section 311 transportation in its East and West Zones. Finally, Enogex may charge the applicable fixed zonal fuel percentage(s) for the fuel used in transporting natural gas under Section 311 on Enogex's system. The fuel percentages are the same for firm and interruptible Section 311 services.

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 Section 311 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. Enogex did not place the increased rates set forth in its October 2007 rate filing into effect but rather continued to provide interruptible Section 311 service under the maximum Section 311 rates for both zones approved by the FERC in the previous rate case. A final settlement was filed with the FERC on August 5, 2010. With the filing of Enogex's Section 311 2009 rate case discussed below, the rate period for the 2007 rate case became a limited locked-in period from January 2008 through May 2009. On October 13, 2011, the FERC issued an order in this matter approving the settlement agreement, providing that Enogex's rates from its previous rate case remain in effect and that the MEP lease agreement discussed below would be addressed in Enogex's Section 311 2009 rate case. This matter is now closed.

Enogex FERC Section 311 2009 Rate Case

On March 27, 2009, Enogex filed a petition for rate approval with the FERC to set the maximum rates for its new firm East Zone Section 311 transportation service and to revise the rates for its existing East and West Zone interruptible Section 311 transportation service. In anticipation of offering this new service, Enogex had filed with the FERC, as required by the FERC's regulations, a revised Statement of Operating Conditions Applicable to Transportation Services to describe the terms, conditions and operating arrangements for the new service. Enogex made the Statement of Operating Conditions filing on February 27, 2009. Enogex began offering firm East Zone Section 311 transportation service on April 1, 2009. The revised East and West Zone zonal rates for the Section 311 interruptible transportation service became effective June 1, 2009. The rates for the firm East Zone Section 311 transportation service and the increase in the rates for East and West Zone and interruptible Section 311 service were collected, subject to refund, pending the FERC approval of the proposed rates. A number of parties intervened in both the rate case and the Statement of Operating Conditions filing and some additionally filed protests. On January 4, 2010, the FERC Staff submitted an offer proposing various adjustments to Enogex's filed cost of service. On April 27, 2010, Enogex submitted comments to the FERC Staff stating that it would agree to the offer, contingent upon all parties agreeing to support or not oppose. On October 4, 2011, Enogex filed a settlement agreement with the FERC which included a proposed refund to shippers of $2.1 million related to the increase in the rates for East and West Zone and interruptible Section 311 service which were collected, subject to refund, pending the FERC approval of the proposed rates. This refund was made to shippers in January 2012. On December 16, 2011, the FERC issued an order approving the settlement agreement. Also, as discussed below, the MEP lease agreement was addressed in this rate case.

On November 13, 2007, one of the protesting intervenors filed to consolidate the Enogex 2007 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 MEP pipeline and to lease firm capacity from Enogex. Enogex and MEP separately opposed this intervenor's protests and assertions in its initial and subsequent pleadings. On July 25, 2008, the FERC issued an order (i) approving the MEP project including the approval of a limited jurisdiction certificate and (ii) authorizing the Enogex lease agreement with MEP. Accordingly, Enogex proceeded with the construction of facilities necessary to implement this service. On August 25, 2008, a protestor sought rehearing which the FERC denied. Enogex commenced service to MEP under the lease agreement on June 1, 2009. On July 16, 2009, the protestor filed, with the United States Court of Appeals for the District of Columbia Circuit, a petition for review of the FERC's orders approving the MEP construction and the MEP lease of capacity from Enogex requesting that such orders be modified or set aside on the grounds that they are arbitrary, capricious and contrary to law. On December 28, 2010, the Court of Appeals issued an opinion generally upholding the FERC's orders, but remanding the case for further explanation of one aspect of the FERC's reasoning. The Court of Appeals emphasized that it was not vacating the FERC's orders and that its approval of the Enogex lease agreement with MEP remains in effect and legally binding. On remand, the FERC was to clarify that its decision was based on a finding that the lease does not adversely affect existing customers on Enogex's system. On January 21, 2011, Apache Corporation filed a motion asking the FERC to establish procedures on remand and to either condition the lease on Enogex's willingness to provide firm Section 311 transportation service to existing customers on all portions of its system or to establish an expedited briefing schedule. On February 7, 2011, Enogex, MEP and Chesapeake Energy Corporation filed a joint answer asking the FERC to find, among other things, that the reduction in the amount of interruptible transportation capacity available due to the MEP lease did not have an adverse affect on Apache Corporation and to acknowledge that Apache Corporation's request to condition the lease on the provision of West Zone 311 firm transportation service has been addressed as Enogex filed a rate case on January 28, 2011 proposing to implement such service effective March 1, 2011. On March 1, 2011, Apache Corporation filed an answer seeking to refute some of the arguments presented in the joint answer filed by Enogex, MEP and Chesapeake Energy Corporation. On March 3, 2011, the FERC issued an order on remand affirming the authorizations previously granted to Enogex and MEP and clarifying the applicable legal standard in response to the court's directive. On April 4, 2011, Apache Corporation filed a request for rehearing of the FERC's order on remand. On September 29, 2011, the FERC issued an order denying Apache Corporation's motion for rehearing. Apache Corporation did not appeal the FERC's March 3, 2011 order on remand and/or the September 29, 2011 order denying rehearing. This matter is now closed.

Enogex Storage Statement of Operating Conditions Filing

On August 31, 2010, Enogex filed via eTariff with the FERC a new Statement of Operating Conditions applicable to storage services that replaced Enogex's existing storage Statement of Operating Conditions effective July 30, 2010. Among other things, the new storage Statement of Operating Conditions updates the general terms and conditions for providing storage services. A FERC order is pending.

Enogex FERC Section 311 2011 Rate Case

On January 28, 2011, Enogex submitted a new rate filing to the FERC to set the maximum rate for a new firm Section 311 transportation service in the West Zone of its system and to revise the currently effective maximum rates for Section 311 interruptible transportation service in the East Zone and West Zone. Along with establishing the rate for a new firm service in the West Zone, Enogex's filing requested a decrease in the maximum interruptible zonal rates in the West Zone and to retain the currently effective rates for firm and interruptible services in the East Zone. Enogex reserved the right to implement the higher rates for firm and interruptible services in the East Zone supported by the cost of service to the extent an expeditious settlement agreement cannot be reached in the proceeding. Enogex proposed that the rates be placed into effect on March 1, 2011. The deadline for interventions and protests on Enogex's filing was November 28, 2011 and no protests were filed. On January 10, 2012, Enogex filed a settlement agreement with the FERC. The deadline for comments to the filing was January 17, 2012, and no comments opposing the settlement were filed. A FERC order is pending.

Enogex 2011 Fuel Filing

On February 28, 2011, Enogex submitted its annual fuel filing to establish the fixed fuel percentages for its East Zone and West Zone for the upcoming fuel year (April 1, 2011 through March 31, 2012). Along with the revised fuel percentages, Enogex also requested authority to revise its Statement of Operating Conditions to permanently change the annual filing date to February 28. The deadline for interventions and protests on Enogex's filing was March 15, 2011, and no protests were filed. A FERC order is pending.

Recent System Expansions

Over the past several years, Enogex has initiated multiple organic growth projects to increase capacity across its system.

In December 2006, Enogex entered into a firm capacity lease agreement with MEP for a primary term of 10 years (subject to possible extension) that gives 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 included construction by MEP of a new pipeline originating near Bennington, Oklahoma and terminating in Butler, Alabama. In support of the MEP lease agreement, Enogex constructed 43 miles of 24-inch steel pipe in Woods and Major counties in Oklahoma, and added 24,000 horsepower of electric-driven compression in Bennington, Oklahoma. Enogex's capital expenditures allocated to its support of the MEP lease agreement were $99 million. Enogex commenced service to MEP under the lease agreement on June 1, 2009.

In order to accommodate additional deliveries to Bennington, Oklahoma, Enogex added an incremental 17,200 horsepower of gas turbine compression at its Bennington compressor station, as well as other system upgrades. These projects were placed in service in December 2010 and January 2011. The capital expenditures associated with these projects were $27 million.

In August 2010, Enogex completed construction of transportation and compression facilities necessary to provide gas delivery service to a new natural gas-fired electric generation facility near Pryor, Oklahoma. Aid in Construction payments of $36.4 million received in excess of construction costs were recognized as Deferred Revenues on the Company's Consolidated Balance Sheet and are being amortized on a straight-line basis of $1.2 million per year over the life of the related firm transportation service agreement under which service commenced in June 2011.

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. 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 methane and ethane.

Enogex's gathering system includes approximately 6,019 miles of intrastate natural gas gathering pipelines in Oklahoma and Texas with 1.36 TBtu/d of average daily gathered volumes in 2011. Enogex owns and operates eight natural gas processing plants, with a current total inlet capacity of 1,105 MMcf/d and has contracted to have access to up to 230 MMcf/d of capacity in six third-party plants. 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 processing plants operated or utilized by Enogex. The resulting processed stream of natural gas is then delivered from the tailgate of each plant into Enogex's intrastate natural gas transportation system. In 2011, Enogex extracted and sold 685 million gallons of NGLs.

Enogex also has a 50 percent interest in Atoka, which operated a 20 MMcf/d refrigeration processing plant which processed gas gathered in the Atoka area. The processing plant was leased on a month-to-month basis. In August 2011, management made a decision to use third-party processing exclusively for gathered volumes dedicated to Atoka and, therefore, to take the processing plant out of service and return it to the lessor in accordance with the rental agreement. See Note 5 of Notes to Consolidated Financial Statements for a further discussion.

Enogex gathers and processes natural gas pursuant to a variety of arrangements generally categorized as fee-based, percent-of-proceeds, percent-of-liquids and keep-whole arrangements. Percent-of-proceeds, percent-of-liquids and keep-whole arrangements involve varying levels of commodity price risk to Enogex because Enogex's margin is based in part on natural gas and NGLs prices. Enogex seeks to mitigate 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 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. However, a sustained decline 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, 2011, these arrangements accounted for 31 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, 2011, these arrangements accounted for 44 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 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. 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 British thermal unit value in natural gas. At December 31, 2011, these arrangements accounted for 25 percent of Enogex's natural gas processed volumes.

In August 2011, Enogex and one of its five largest customers entered into new agreements, effective July 1, 2011, relating to the customer's gathering and processing volumes on the Oklahoma portion of Enogex's system. The effect of this new arrangement is that (i) the acreage dedicated by the customer to Enogex for gathering and processing in Oklahoma has been increased for an extended term and (ii) the processing arrangement has been converted from keep-whole to fixed fee. This customer's converted volumes represented 8.4 percent of total inlet volumes from July 1, 2011 to December 31, 2011. Also, as a result of this transaction and as part of the new agreements, Enogex recorded $6.4 million in Deferred Revenues on the Company's Consolidated Balance Sheet at December 31, 2011. Processing revenues under the agreements are recognized based on the estimated average fee per MMBtu processed over the life of the agreements. Enogex expects to record additional deferred revenues during 2012.

Enogex's gathering and processing contracts typically contain terms and conditions that require a "default processing fee" in the event the gathered gas exceeds downstream interconnect specifications. Natural gas that is greater than 1,080 British thermal unit 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 British thermal unit 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 British thermal unit per cubic foot when the price of the NGLs to be extracted and sold is less than the British thermal unit value of the natural gas that Enogex otherwise would be required to replace.

Of the commercial grade propane produced at Enogex's processing plants, 14 percent 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 or 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 Roger Mills and Calumet plants, 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 western Oklahoma and the Wheeler County area in the Texas Panhandle can flow to the Cox City, Thomas, Calumet or South Canadian gas processing plants. These large-diameter "super-header" gathering system of Enogex provides gas routing flexibility for Enogex to optimize the economics of its gas processing and to improve system utilization and reliability.

In order to meet the growing requirements of its customers, Enogex continues to evaluate the need to expand its processing capabilities on the "super-header" gathering system, such as the 200 MMcf/d processing plant in Canadian County which was placed in service in December 2011 and the 200 MMcf/d processing plant currently under construction in Wheeler County, Texas and the 200 MMcf/d processing plant which will be installed in Custer County, Oklahoma.

Customers and Contracts

The natural gas remaining after processing is primarily taken in kind by the producer customers into Enogex's transportation pipelines for redelivery either: (i) to on-system customers such as the electric generation facilities of OG&E, PSO, other independent power producers and other end-users or (ii) into downstream interstate pipelines. Enogex's NGLs are typically sold to NGLs 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 in 2011 included Chesapeake Energy Marketing Inc., Apache Corporation, Devon Energy Production Company, L.P., BP America Production Company and Kaiser Francis Oil Co. In 2011, these five customers accounted for 19.9 percent, 15.0 percent, 12.5 percent, 4.1 percent and 3.9 percent, respectively, of Enogex's gathering and processing volumes. In 2011, Enogex's top 10 natural gas producer customers accounted for 69.4 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 Chesapeake Midstream Partners, L.P., Crosstex Energy LP, DCP Midstream Partners, LP, Enbridge Energy Partners, L.P., 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. Texas has also adopted a complaint based regulation, known as the lost and unaccounted for gas bill, which expands the types of information that can be requested and gives the Texas Railroad Commission the authority to make determinations and issue orders for purposes of preventing waste in specific situations. To date, neither the gathering regulations nor the lost and unaccounted for gas bill have had a significant impact on Enogex's operations in Oklahoma or Texas. However, Enogex cannot predict what effect, if any, either of these regulations might have on its gathering operations in Oklahoma or Texas 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 could also be subject to additional safety and operational regulations relating to the design, construction, testing, operation, replacement and maintenance 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 west side of Enogex's gathering system, primarily in the Cana/Woodford Shale play and the Colony Wash play in western Oklahoma and the Granite Wash play in western Oklahoma and in the Wheeler County, Texas area, which is located in the Texas Panhandle.

Enogex constructed a new 200 MMcf/d cryogenic processing plant in Canadian County, Oklahoma. The new plant, which has inlet and residue compression and is supported by the installation of 31 miles of 20-inch gathering pipeline, as well as 11 miles of 24-inch transmission pipeline providing takeaway capacity from the plant tailgate, was placed in service in December 2011. The total capital expenditures associated with this project were $140 million.

Enogex expects to expand its cryogenic processing plant currently under construction in Wheeler County, Texas from a processing capacity of 120 MMcf/d to 200 MMcf/d with the installation of additional residue compression facilities. The initial processing capacity of 120 MMcf/d is expected to be in service at the beginning of the third quarter of 2012, and the additional processing capacity is expected to be in service by the end of the third quarter of 2012. The new plant will be supported by the installation of 9,400 horsepower of field compression. The total capital expenditures associated with this project are expected to be $140 million.

In support of significant long-term acreage dedications from its customers in the area, Enogex continues to expand its gathering infrastructure in four counties of western Oklahoma. These expansions are planned to occur in phases, with the initial phase calling for the installation of 47,980 horsepower of low pressure compression and over 300 miles of gathering pipe across the area. This infrastructure is expected to be constructed throughout 2012 and 2013. The total capital expenditures associated with these expansions projects are expected to be $240 million.

Enogex expects to install a 200 MMcf/d cryogenic processing plant in Custer County, Oklahoma. The new plant will be supported by 6,000 horsepower of inlet compression and 25 miles of transmission pipeline. This plant is expected to be in service by the end of the third quarter of 2013. The total capital expenditures associated with this project are expected to be $135 million.

Disposition

On April 1, 2011, Enogex completed the sale of its Harrah processing plant (38 MMcf/d of capacity) and the associated Wellston and Davenport gathering assets. The proceeds from the sale were $15.9 million and Enogex recorded a pre-tax gain in the second quarter of 2011 of $3.7 million.

Gas Gathering Acquisitions

On September 23, 2011, Enogex entered into the following agreements: an agreement with Cordillera, Oxbow and West Canadian Midstream LLC pursuant to which Enogex agreed to acquire 100 percent of the membership interest in Roger Mills Gas Gathering, LLC, an Oklahoma limited liability company that owns an approximately 60-mile natural gas gathering system located in Roger Mills County and Ellis County, Oklahoma; an agreement with Cordillera and Oxbow pursuant to which Enogex agreed to acquire an approximately 30-mile natural gas gathering system located in Roger Mills County, Oklahoma; and agreements with Cordillera and other producers pursuant to which such producers agreed to provide Enogex with long-term acreage dedication in the area served by the gathering systems encompassing approximately 100,000 net acres. The gathering systems are located in the Granite Wash area. The aggregate purchase price for these transactions was $200.4 million which was paid in cash primarily from contributions from OGE Energy and the ArcLight group (as discussed in Note 4 of Notes to Consolidated Financial Statements) as well as cash generated from operations and bank borrowings. The transactions closed on November 1, 2011. Enogex believes that the transactions will provide Enogex with key new opportunities in the Granite Wash area. See Note 3 of Notes to Consolidated Financial Statements for a further discussion.

In support of the acquisitions described above, Enogex plans to construct 20 miles of 16-inch gathering pipe and over 11,000 horsepower of low pressure compression in 2012. The total capital expenditures for these projects are expected to be $55 million.

Enogex Cox City Plant Fire

On December 8, 2010, a fire occurred at Enogex's Cox City natural gas processing plant destroying major components of one of the four processing trains, representing 120 MMcf/d of the total 180 MMcf/d of capacity, at that facility. Gas volumes normally processed at the Cox City plant were diverted to other facilities or bypassed around Enogex's system to accommodate production and all of the impacted gathered volumes were back online in December 2010. The damaged train was replaced and the facility was returned to full service in September 2011. The total cost necessary to return the facility back to full service was $29.6 million. While Enogex believes that the costs in excess of the $10 million deductible should be reimbursed by insurance, the matter is currently being negotiated with the insurance company and Enogex cannot predict the precise outcome of these negotiations or the timing associated with the recovery. In the fourth quarter of 2011, Enogex received a partial insurance reimbursement of $7.4 million and recognized a gain of $3.0 million on insurance proceeds. Enogex expects to receive additional reimbursement of portions of the costs in 2012. Enogex will recognize insurance recoveries in earnings as the insurance claims are resolved.

Safety and Health Regulation

Certain of Enogex's facilities are subject to pipeline transportation regulations, including the Pipeline Safety Improvement Act of 2002 and the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006. The Pipeline and Hazardous Materials Safety Administration regulates safety requirements in the design, construction, operation and maintenance of applicable natural gas and hazardous liquid pipeline facilities. The Pipeline Safety Improvement Act of 2002 and the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 require mandatory inspections and enforcement for all U.S. hazardous liquid and natural gas transportation pipelines, including some gathering lines in high population areas. The U.S. Department of Transportation has developed regulations implementing the Pipeline Safety Improvement Act of 2002 that require pipeline operators to implement integrity management programs, including more frequent inspections and other safety protections in high-consequence areas where threats pose the greatest risk to people and their property. For example, the U.S. Department of Transportation has adopted regulations requiring pipeline operators to develop integrity management programs for their applicable pipelines. In 2011, Enogex incurred $23.0 million of capital expenditures and operating costs for pipeline integrity management. Enogex currently estimates that it will incur capital expenditures and operating costs of between $100 million and $160 million from 2012 to 2016 in connection with pipeline integrity management. 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. At this time, Enogex cannot predict the ultimate costs of its integrity management program and compliance with this regulation because those costs will depend on the number and extent of any repairs found to be necessary. Enogex will continue 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.

On December 13, 2011, Congress passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which the President signed into law on January 3, 2012. Among other things, the law requires additional verification of pipeline infrastructure records by Enogex and other intrastate and interstate pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. Where records are inadequate to confirm the maximum allowable operating pressure, the PHMSA will require the operator to re-confirm the maximum allowable operating pressure, a process that could cause temporary or permanent limitations on throughput for affected pipelines. This law requires PHMSA to direct pipeline operators to verify the maximum allowable operating pressure of their pipelines by July 3, 2012, and to submit documentation to PHMSA by July 3, 2013. This law also raises the maximum penalty for violating pipeline safety rules to $0.2 million per violation per day up to $2.0 million for a related series of violations. For further information regarding this Act and potential regulations, see Note 16 of Notes to Consolidated Financial Statements. At this time, the Company is not able to estimate the capital, operating or other costs that may be required to comply with this law and any related PHMSA regulations that may be promulgated, but such costs could be significant.

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 U.S. Department of Transportation. A similar regime for safety regulation is in place in Texas and administered by the Texas Railroad Commission. Enogex's natural gas pipelines have inspection and audit 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

General

OER 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 OER's business on Enogex's system. OER 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.

OER primarily participates in both intermediate-term markets (less than three years) and short-term "spot" markets for natural gas. Although OER 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. OER's average daily sales volumes were 0.5 billion cubic feet in both 2011 and 2010. OER'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 OER by buying and selling natural gas futures contracts on the NYMEX 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

OER competes with major integrated oil companies, commercial banks, national and local natural gas marketers, distribution companies and marketing affiliates of interstate and intrastate pipelines in marketing natural gas. Competition for both natural gas supplies and natural gas sales is based primarily on reputation, accuracy, flexibility, products offered, credit support, the availability to transport gas to high-demand markets and the ability to obtain a satisfactory price for the natural gas.

In 2011, 60 percent of OER's service volumes were with electric utilities, local gas distribution companies, pipelines and producers, of which 31 percent was with affiliates of OER. The remaining 40 percent of OER's service volumes were to marketers, municipals, cooperatives and industrials. At December 31, 2011, 69 percent of the payment exposure was to companies having investment grade ratings with Standard & Poor's Ratings Services and two percent was to companies having less than investment grade ratings with Standard & Poor's Rating Services. The remaining 29 percent of OER's exposure is with privately held companies, municipals or cooperatives that were not rated by Standard & Poor's Ratings Services. OER applies internal credit analyses and policies to these non-rated companies. At December 31, 2011, all but $1.2 million of OER's exposure was to counterparties who were investment grade or deemed investment grade equivalents based upon OER's internal credit analyses.

Regulation

The price at which OER 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, OER is required to observe anti-market manipulation laws and related regulations enforced by the FERC and/or the Commodity Futures Trading Commission. The FERC and Commodity Futures Trading Commission 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 OER 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.

On July 21, 2010, President Obama signed into law the Dodd-Frank Act. While the Dodd-Frank Act is focused primarily on the regulation and oversight of financial institutions, it also provides for a new regulatory regime for derivatives, including mandatory clearing of certain swaps, exchange trading, margin requirements and other transparency requirements. The impact of the provisions of the Dodd-Frank Act on the OER cannot be determined pending issuance of the final implementing regulations. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Potential Collateral Requirements" for further discussion of the Dodd-Frank Act.

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 including 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 their wastes, requiring remedial action to mitigate pollution conditions that may be caused by their operations or that are attributable to former operators, regulating future construction activities to mitigate harm to threatened or endangered species and requiring the installation and operation of pollution control equipment. 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. OG&E and Enogex believe that their operations are in substantial compliance with current Federal, state and local environmental standards.

The trend in environmental regulation, however, is to place more restrictions and limitations on activities that may affect the environment. OG&E and Enogex cannot assure that future events, such as changes in existing laws, the promulgation of new laws or regulations, or the development or discovery of new facts or conditions will not cause them to incur significant costs. Management continues to evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

Of the Company's capital expenditures budgeted for 2012, $34.4 million are to comply with environmental laws and regulations, of which $33.7 million and $0.7 million are related to OG&E and Enogex, respectively. Of the Company's capital expenditures budgeted for 2013, $36.0 million are to comply with environmental laws and regulations, of which $35.3 million and $0.7 million are related to OG&E and Enogex, respectively. The Company's management believes that all of its operations are in substantial compliance with current Federal, state and local environmental standards. It is estimated that OG&E's and Enogex's total expenditures for capital, operating, maintenance and other costs associated with environmental quality will be $51.6 million and $6.2 million, respectively, in 2012 as compared to $24.0 million and $6.5 million, respectively, in 2011. Management continues to evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

For a further discussion of environmental matters that may affect the Company, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Laws and Regulations."

FINANCE AND CONSTRUCTION

Future Capital Requirements and Financing Activities

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, 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. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources" for a discussion of the Company's capital requirements.

Capital Expenditures

The Company's consolidated estimates of capital expenditures for the years 2012 through 2016 are shown in the following table. These capital expenditures represent the base maintenance capital expenditures (i.e., capital expenditures to maintain and operate the Company's businesses) plus capital expenditures for known and committed projects.

(In millions)	2012	2013	2014	2015	2016
OG&E Base Transmission	$ 80	$ 50	$ 50	$ 50	$ 50
OG&E Base Distribution	195	200	200	200	200
OG&E Base Generation	110	80	80	80	80
OG&E Other	30	30	30	30	30
Total OG&E Base Transmission, Distribution, Generation and Other	415	360	360	360	360
OG&E Known and Committed Projects:					
Transmission Projects:					
Sunnyside-Hugo (345 kilovolt)	25	—	—	—	—
Sooner-Rose Hill (345 kilovolt)	5	—	—	—	—
Balanced Portfolio 3E Projects	110	180	50	—	—
SPP Priority Projects	20	200	115	—	—
Total Transmission Projects	160	380	165	—	—
Other Projects:					
Smart Grid Program (A)	90	35	40	20	20
Crossroads	40	—	—	—	—
System Hardening	15	—	—	—	—
Total Other Projects	145	35	40	20	20
Total OG&E Known and Committed Projects	305	415	205	20	20
Total OG&E (B)	720	775	565	380	380
Enogex LLC Base Maintenance	60	50	55	60	65
Enogex LLC Known and Committed Projects:					
Western Oklahoma / Texas Panhandle Gathering Expansion	215	115	15	5	5
Other Gathering Expansion	25	25	20	20	20
Total Enogex LLC Known and Committed Projects	240	140	35	25	25
Total Enogex LLC (C)	300	190	90	85	90
OGE Energy	20	20	20	20	20
Total capital expenditures	$ 1,040	$ 985	$ 675	$ 485	$ 490

(A) These capital expenditures are net of the $130 million Smart Grid grant approved by the U.S. Department of Energy.
(B) The capital expenditures above exclude any environmental expenditures associated with pollution control equipment related to regional haze requirements due to the uncertainty regarding the timing and costs for such pollution control equipment. OG&E has committed to install low NOX burners at the affected generating units at a cost preliminarily estimated between $70 million and $130 million, but the timing of the installation of such burners is uncertain. The SO2 emissions standards in the EPA's Federal implementation plan could require the installation of Dry Scrubbers or fuel switching. OG&E estimates that installing such Dry Scrubbers could cost more than $1.0 billion. The Federal implementation plan is being challenged by OG&E and the state of Oklahoma. Neither the outcome of the challenge to the Federal implementation plan nor the timing and amount of any required capital expenditures can be predicted with any certainty at this time, but such capital expenditures could be significant. For further information, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Environmental Laws and Regulations" below.
(C) These capital expenditures represent 100 percent of Enogex LLC's capital expenditures, of which a portion may be funded by the ArcLight group. Until the ArcLight group owns 50 percent of the equity of Enogex Holdings, the ArcLight group will fund capital contributions in an amount higher than its proportionate interest. If necessary, the ArcLight group will fund between 50 percent and 90 percent of required capital contributions during that period. The remainder of the required capital contributions (i.e., between 10 percent and 50 percent) will be funded by OGE Holdings.

Additional capital expenditures beyond those identified in the table above, including additional incremental growth opportunities in electric transmission assets and at Enogex LLC, will be evaluated based upon their impact upon achieving the Company's financial objectives. The capital expenditure projections related to Enogex LLC in the table above reflect base market conditions at February 16, 2012 and do not reflect the potential opportunity for a set of growth projects that could materialize. Also, if drilling activity declines in the future, this could reduce Enogex's capital expenditures in the table above.

Pension and Postretirement Benefit Plans

During each of 2011 and 2010, OGE Energy made contributions to its Pension Plan of $50 million to help ensure that the Pension Plan maintains an adequate funded status. During 2012, OGE Energy may contribute up to $35 million to its Pension

Plan. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Future Capital Requirements and Financing Activities" for a discussion of OGE Energy's pension and postretirement benefit plans.

Common Stock Dividends

At the Company's December 2011 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 $0.3925 per share from $0.3750 per share effective with the Company's first quarter 2012 dividend. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Future Capital Requirements and Financing Activities" for a further discussion.

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 and to fund future growth opportunities. Additionally, the Company will have an additional source of funding for growth opportunities at Enogex through the ArcLight group and from quarterly distributions from Enogex Holdings. 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 and Credit Facilities

Short-term borrowings generally are used to meet working capital requirements. The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. In December 2011, the Company, OG&E and Enogex LLC each entered into new unsecured five-year revolving credit facilities totaling in the aggregate $1,550 million ($750 million for the Company, $400 million for OG&E and $400 million for Enogex LLC). The short-term debt balance was $277.1 million and $145.0 million at December 31, 2011 and 2010, respectively. The weighted-average interest rate on short-term debt at December 31, 2011 was 0.48 percent. The average balance of short-term debt in 2011 was $210.7 million at a weighted-average interest rate of 0.36 percent. The maximum month-end balance of short-term debt in 2011 was $323.0 million. Enogex had $150.0 million and $25.0 million in outstanding borrowings under its revolving credit agreement at December 31, 2011 and 2010, respectively. As Enogex LLC's credit agreement matures on December 13, 2016, along with its intent in utilizing its credit agreement, borrowings thereunder are classified as long-term debt in the Company's Consolidated Balance Sheets. At December 31, 2011, the Company had $1,120.7 million of net available liquidity under its revolving credit agreements. 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, 2011 and ending December 31, 2012. At December 31, 2011, the Company had $4.6 million in cash and cash equivalents. See Note 13 of Notes to Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

Expected Issuance of Long-Term Debt

OG&E expects to issue approximately $250 million of long-term debt in late 2012, depending on market conditions, to fund capital expenditures, repay short-term borrowings and for general corporate purposes.

Common Stock

The Company expects to issue between $13 million and $15 million of common stock in its Automatic Dividend Reinvestment and Stock Purchase Plan in 2012. See Note 11 of Notes to Consolidated Financial Statements for a discussion of the Company's common stock activity.

Minimum Quarterly Distributions by Enogex Holdings

Pursuant to the Enogex Holdings LLC Agreement, Enogex Holdings will make minimum quarterly distributions equal to the amount of cash required to cover OGE Energy's anticipated tax liabilities plus $12.5 million, to be distributed in proportion to each member's percentage ownership interest.

EMPLOYEES

The Company and its subsidiaries had 3,489 employees at December 31, 2011.

EXECUTIVE OFFICERS

The following persons were Executive Officers of the Registrant as of February 16, 2012:

Name	Age	Title
Peter B. Delaney	58	Chairman of the Board, President and Chief Executive Officer - OGE Energy Corp.
Sean Trauschke	44	Vice President and Chief Financial Officer - OGE Energy Corp.
E. Keith Mitchell	49	President and Chief Operating Officer - Enogex Holdings
Stephen E. Merrill	47	Chief Operating Officer of Enogex LLC
William J. Bullard	63	Assistant General Counsel - OGE Energy Corp.
Scott Forbes	54	Controller and Chief Accounting Officer - OGE Energy Corp.
Patricia D. Horn	53	Vice President - Governance, Environmental, Health & Safety; Corporate Secretary - OGE Energy Corp.
Gary D. Huneryager	61	Vice President - Internal Audits - OGE Energy Corp.
Jesse B. Langston	49	Vice President - Retail Energy - OG&E
Jean C. Leger, Jr.	53	Vice President - Utility Operations - OG&E
Cristina F. McQuistion	47	Vice President - Strategy and Performance Improvement - OGE Energy Corp.
Max J. Myers	37	Treasurer - OGE Energy Corp.
Reid V. Nuttall	54	Vice President - Chief Information Officer - OGE Energy Corp.
Jerry A. Peace	49	Chief Risk Officer - OGE Energy Corp.
Paul L. Renfrow	55	Vice President - Public Affairs and Human Resources - OGE Energy Corp.

No family relationship exists between any of the Executive Officers of the Registrant. Messrs. Delaney, Trauschke, Bullard, Forbes, Huneryager, Myers, Nuttall, Peace, Renfrow and Ms. Horn and Ms. McQuistion are also officers of OG&E. Messrs. Delaney, Trauschke, Mitchell, Myers and Ms. Horn are also officers of Enogex Holdings and/or its subsidiaries. Each Executive Officer is to hold office until the Board of Directors meeting following the next Annual Meeting of Shareowners, currently scheduled for May 17, 2012.

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	2012 - Present:	Chairman of the Board, President and Chief Executive Officer of OGE Energy Corp. and OG&E
	2010 - 2011:	Chairman of the Board and Chief Executive Officer of OGE Energy Corp. and OG&E
	2010 - Present:	Chief Executive Officer of Enogex Holdings LLC
	2008 - Present:	Chief Executive Officer of Enogex LLC
	2007 - 2010:	Chairman of the Board, President and Chief Executive Officer of OGE Energy Corp. and OG&E
	2007 - 2008:	Chief Executive Officer of Enogex Inc.
	2007:	President and Chief Operating Officer of OGE Energy Corp. and OG&E
	2007:	Executive Vice President and Chief Operating Officer of OGE Energy Corp. and OG&E
Sean Trauschke	2009 - Present:	Vice President and Chief Financial Officer of OGE Energy Corp. and OG&E
	2010 - Present:	Chief Financial Officer of Enogex Holdings LLC
	2009 - Present:	Chief Financial Officer of Enogex LLC
	2007 - 2009:	Senior Vice President - Investor Relations and Financial Planning of Duke Energy
	2007:	Vice President - Investor Relations of Duke Energy (electric utility)
E. Keith Mitchell	2011 - Present:	President and Chief Operating Officer of Enogex Holdings LLC; President of Enogex LLC
	2008 - 2011:	Senior Vice President and Chief Operating Officer of Enogex LLC
	2007 - 2008:	Senior Vice President and Chief Operating Officer of Enogex Inc.
	2007:	Senior Vice President of Enogex Inc.
	2007:	Vice President - Transportation Services of Enogex Inc.
Stephen E. Merrill	2011 - Present:	Chief Operating Officer of Enogex LLC
	2009 - 2011:	Vice President - Human Resources of OGE Energy Corp. and OG&E
	2008 - 2009:	Vice President and Chief Financial Officer of Enogex LLC
	2007 - 2008:	Vice President and Chief Financial Officer of Enogex Inc.
	2007:	Vice President and Chief Financial Officer of Cayenne Drilling, LLC and Sunstone Energy Group LLC (oil and gas company)
William J. Bullard	2010 - Present:	Assistant General Counsel of OGE Energy Corp.; General Counsel of OG&E
	2007 - 2010:	Assistant General Counsel of OGE Energy Corp. and OG&E
Scott Forbes	2007 - Present:	Controller and Chief Accounting Officer of OGE Energy Corp. and OG&E
	2008 - 2009:	Interim Chief Financial Officer of OGE Energy Corp. and OG&E
Patricia D. Horn	2010 - Present:	Vice President - Governance, Environmental, Health & Safety; Corporate Secretary of OGE Energy Corp. and OG&E; Secretary of Enogex Holdings LLC; Corporate Secretary of Enogex LLC
	2008 - 2010:	Vice President - Legal, Regulatory, Environmental Health & Safety, General Counsel and Secretary of Enogex LLC
	2007 - 2010:	Assistant General Counsel of OGE Energy Corp.
	2007 - 2008:	Vice President - Legal, Regulatory, Environmental Health & Safety, General Counsel and Secretary of Enogex Inc.
Gary D. Huneryager	2007 - Present:	Vice President - Internal Audits of OGE Energy Corp. and OG&E
Jesse B. Langston	2011 - Present:	Vice President - Retail Energy of OG&E
	2007 - 2011:	Vice President - Utility Commercial Operations of OG&E
Jean C. Leger, Jr.	2008 - Present:	Vice President - Utility Operations of OG&E
	2007 - 2008:	Vice President of Operations of Enogex Inc.

Name		Business Experience
Cristina F. McQuistion	2011 - Present:	Vice President - Strategy and Performance Improvement of OGE Energy Corp. and OG&E
	2008 - 2011:	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
	2007:	Executive Vice President - Member Services of Teleflora (floral industry and software services to floral industry company)
Max J. Myers	2009 - Present:	Treasurer of OGE Energy Corp. and OG&E
	2010 - Present:	Treasurer of Enogex Holdings LLC
	2008 - 2009:	Managing Director of Corporate Development and Finance of OGE Energy Corp. and OG&E
	2007 - 2008:	Manager of Corporate Development of OGE Energy Corp. and OG&E
Reid V. Nuttall	2009 - Present:	Vice President - Chief Information Officer of OGE Energy Corp. and OG&E
	2007 - 2009:	Vice President - Enterprise Information and Performance of OGE Energy Corp. and OG&E
Jerry A. Peace	2008 - Present:	Chief Risk Officer of OGE Energy Corp. and OG&E
	2007 - 2008:	Chief Risk Officer and Compliance Officer of OGE Energy Corp. and OG&E
Paul L. Renfrow	2011 - Present:	Vice President - Public Affairs and Human Resources of OGE Energy Corp. and OG&E
	2007 - 2011:	Vice President - Public Affairs of OGE Energy Corp. and OG&E

ACCESS TO SECURITIES AND EXCHANGE COMMISSION FILINGS

The Company's web site address is *www.oge.com*. Through the Company's website under the heading "Investor Relations," "SEC Filings," the Company makes available, free of charge, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act as soon as reasonably practicable after such material is electronically filed with or furnished to the Securities and Exchange Commission. Our Internet website and the information contained therein or connected thereto are not intended to be incorporated into this Form 10-K and should not be considered a part of this Form 10-K.

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 OGE Enogex Holdings and its subsidiaries. In addition to the other information in this Form 10-K and other documents filed by us and/or our subsidiaries with the Securities and Exchange Commission 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. 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 rate 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 rate 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 conservation, 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. For example, the EPA rules could require significant capital and operating expenditures to achieve reductions in emissions of SO2 and NOX over the next five years.

In response to public concern about global climate change, emissions of greenhouse gases including, most significantly, carbon dioxide could be restricted in the future as a result of Federal or state legal requirements or litigation relating to greenhouse gas emissions. If mandatory reductions of carbon dioxide and other greenhouse gases are required in the future, 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.

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 unable 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.

For a further discussion of environmental matters that may affect the Company, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Environmental Laws and Regulations".

We are subject to physical and financial risks associated with climate change.

Climate change creates physical and financial risk. Physical risks from climate change could include an increase in sea level and changes in weather conditions, such as an increase in changes in precipitation and extreme weather events. OG&E's operations are not sensitive to potential future sea-level rise as it does not operate in coastal areas. However, OG&E's power delivery systems are vulnerable to damage from extreme weather events, such as ice storms, tornadoes and severe thunderstorms. These types of extreme weather events are common on OG&E's system, so OG&E includes storm restoration in its budgeting process as a normal business expense. To the extent the frequency of extreme weather events increases, this could increase OG&E's cost of providing service. OG&E's electric generating facilities are designed to withstand the effects of extreme weather events, however, extreme weather conditions increase the stress placed on such systems. If climate change results in temperature increases in OG&E's service territory, OG&E could expect increased electricity demand due to the increase in temperature and longer warm seasons. While this increase in demand could lead to increased energy consumption, it could also create a physical strain on OG&E's generating resources. At the same time, OG&E could face restrictions on the ability to meet that demand if, due to drought severity, there is a lack of sufficient water for use in cooling during the electricity generating process.

In addition to the above cited risks, to the extent that any climate change adversely affects the national or regional economic health through increased rates caused by the inclusion of additional regulatory imposed costs (carbon dioxide taxes or costs associated with additional regulatory requirements), the Company may be adversely impacted. A declining economy could adversely impact the overall financial health of the Company because of lack of load growth and decreased sales opportunities.

To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this could negatively affect our ability to access capital markets or cause us to receive less than ideal terms and conditions.

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 jurisdictions have fuel clauses that permit us to recover 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 an existing pipeline or constructs 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 construction. 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.

OG&E may not realize the expected benefits of its Smart Grid metering system, the Smart Grid metering system may not perform as intended or OG&E may incur costs to deploy the Smart Grid metering system that are not recoverable in rates which could adversely affect our results of operations, consolidated financial position and cash flows.

In 2010, OG&E began implementing its Smart Grid metering infrastructure project for residential and commercial customers. This project, which is expected to be completed by the end of 2012, involves the installation of approximately 792,000 Smart Grid meters throughout OG&E's service territory. Smart Grid meters will allow customer usage data to be transmitted through a communication network to a central collection point, where the data will be stored and used for customer billing and other commercial purposes.

The costs recoverable from Oklahoma customers for system-wide deployment of smart grid technology and implementing the smart grid pilot program are capped at $366.4 million, (inclusive of the U.S. Department of Energy grant award amount) subject to an offset for any recovery of those costs from Arkansas customers and are currently being recovered through a rider which will remain in effect until the Smart Grid project costs are included in base rates beginning in 2014. To the extent that OG&E's total expenditure for system-wide deployment of smart grid technology during the eligible period exceeds the Smart Grid project cost, OG&E shall be entitled to offer evidence and seek to establish that the excess above the Smart Grid project cost was prudently incurred and any such contention may be addressed in OG&E's next rate case.

If OG&E does not recognize the expected benefits of its Smart Grid metering system, if OG&E incurs additional Smart Grid metering costs that the OCC does not find reasonable or are unrecoverable or if OG&E cannot integrate the Smart Grid metering system with its customer billing and other computer information systems, this may adversely affect our results of operations, consolidated financial position and cash flows.

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 and has transferred operational authority (but not ownership) of OG&E's transmission facilities to the SPP. The SPP implemented a regional energy imbalance service market on February 1, 2007. OG&E participates 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.

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.

Our investment agreement with the ArcLight group involves risks and uncertainties.

As part of our investment agreement with the ArcLight group, we are entitled to designate three directors and the ArcLight group is able to designate one director of Enogex Holdings. The investment agreement provides the ArcLight group the opportunity to increase its ownership interest by providing equity funding for capital expenditures associated with Enogex's business plan. As its ownership position increases, the ArcLight group will be entitled to increasing board representation. As of December 31, 2011, the ArcLight group has an 18.7 percent membership interest in Enogex Holdings. The ArcLight group will also be entitled, at various ownership thresholds, to certain special board approval rights with respect to certain significant actions taken by Enogex Holdings, as well as to appoint additional directors for Enogex Holdings.

Joint venture arrangements like this involve risks and uncertainties, including the risk of the joint venture partner failing to satisfy its obligations, which may result in certain liabilities to us for commitments; the challenges in achieving strategic objectives and expected benefits of the business arrangement and the risk of conflicts arising between us and our partner and the difficulty of managing and resolving such conflicts.

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 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 Natural Gas Policy Act, 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 Natural Gas Policy Act. Rates to provide such service must be "fair and equitable" under the Natural Gas Policy Act and are subject to review and approval by the FERC at least once every three years. See Note 17 of Notes to Consolidated Financial Statements for a discussion of Enogex's FERC Section 311 proceedings. There can be no assurance that the FERC will approve Enogex's requested rates.

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 could also be subject to safety and operational regulations relating to the design, construction, testing, operation, replacement and maintenance 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 and other similar programs and related repairs.

Pursuant to the Pipeline Safety Improvement Act of 2002 , the U.S. Department of Transportation has adopted regulations requiring pipeline operators to develop integrity management programs for their applicable 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 U.S. Department of Transportation and state agencies, including the periodic submission of performance documents to the U.S. Department of Transportation.

In 2011, Enogex incurred $23.0 million of capital expenditures and operating costs for pipeline integrity management. Enogex currently estimates that it will incur capital expenditures and operating costs of between $100 million and $160 million from 2012 to 2016 in connection with pipeline integrity management. 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. At this time, Enogex cannot predict the ultimate costs of its integrity management program and compliance with this regulation because those costs will depend on the number and extent of any repairs found to be necessary. Enogex will continue 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.

On December 13, 2011, Congress passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which the President signed into law on January 3, 2012. Among other things, the law requires additional verification of pipeline infrastructure records by Enogex and other intrastate and interstate pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. Where records are inadequate to confirm the maximum allowable operating pressure, the PHMSA will require the operator to re-confirm the maximum allowable operating pressure, a process that could cause temporary or permanent limitations on throughput for affected pipelines. This law requires PHMSA to direct pipeline operators to verify the maximum allowable operating pressure of their pipelines by July 3, 2012, and to submit documentation to PHMSA by July 3, 2013. This law also raises the maximum penalty for violating pipeline safety rules to $0.2 million per violation per day up to $2.0 million for a related series of violations. For further information regarding this Act and potential regulations, see Note 16 of Notes to Consolidated Financial Statements. At this time, the Company is not able to estimate the capital, operating or other costs that may be required to comply with this law and any related PHMSA regulations that may be promulgated, but such costs could be significant.

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.

In compliance with the Energy Policy Act of 2005, the FERC approved the North American Electric Reliability Corporation as the national energy reliability organization. The North American Electric Reliability Corporation is responsible for the development and enforcement of mandatory reliability and cyber security standards for the wholesale electric power system. The Company's plan is to comply with all applicable standards and to expediently correct a violation should it occur. The North American Electric Reliability Corporation has authority to assess penalties up to $1 million per day per violation for noncompliance. OG&E is subject to a North American Electric Reliability Corporation compliance audit every three years as well as periodic spot check audits 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.

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. 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.

OG&E's electric generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses and increased power purchase costs.

OG&E owns and operates coal-fired, natural gas-fired and wind-powered generating facilities. Operation of electric generating facilities involves risks that can adversely affect energy output and efficiency levels. Included among these risks are:

- Increased prices for fuel and fuel transportation as existing contracts expire;
- Facility shutdowns due to a breakdown or failure of equipment or processes or interruptions in fuel supply;
- Operator error or safety related stoppages;
- Disruptions in the delivery of electricity; and
- Catastrophic events such as fires, explosions, floods or other similar occurrences.

Economic conditions could negatively impact our business and our results of operations.

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. Economic conditions may also impact the valuation of certain long-lived or intangible assets, including goodwill, that are subject to impairment testing, potentially resulting in impairment charges, which could have a material adverse impact on our results of operations.

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.

In addition, economic conditions, particularly budget shortfalls, could lead to increased pressure on Federal, state and local governments to raise additional funds, including through increased corporate taxes and/or through delaying, reducing or eliminating tax credits, grants or other incentives, which could have a material adverse impact on our results of operations.

We are subject to cyber security risks.

In the regular course of our businesses, we handle a range of sensitive security and customer information. We are subject to laws and rules issued by different agencies concerning safeguarding and maintaining the confidentiality of this information. A security breach of our information systems such as theft or inappropriate release of certain types of information, including confidential customer information or system operating information, could have a material adverse impact on the operations and financial condition of the Company.

OG&E and Enogex operate in a highly regulated industry that requires the continued operation of sophisticated information technology systems and network infrastructure. Despite implementation of security measures, the technology systems are vulnerable to disability, failures or unauthorized access. Such failures or breaches of the systems could impact the reliability of OG&E's generation, transmission and distribution systems and Enogex's transportation systems and also subject OG&E and Enogex to financial harm. The implementation of OG&E's Smart Grid program further increases potential risks associated with cyber security attacks. If the technology systems were to fail or be breached and not recovered in a timely way, critical business functions could be impaired and sensitive confidential data could be compromised, which could have a material adverse impact on the operations and financial condition of the Company.

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 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 the construction and 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 NGLs prices are volatile, and changes in these prices could negatively affect Enogex's results of operations and cash flows.

Enogex's results of operations and cash flows could be negatively affected by adverse movements in the prices of natural gas and NGLs depending on factors that are beyond our control. 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, liquefied 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, which constituted 15 percent of its gross margin and accounted for 25 percent of its natural gas processed volumes in 2011, expose it to fluctuations in the pricing spreads between NGLs prices and natural gas prices. Keep-whole processing arrangements generally require a processor of natural gas to keep its shippers whole on a British thermal unit basis by replacing the British thermal units of the NGLs extracted from the production stream with British thermal units of natural gas. Therefore, if natural gas prices increase and NGLs prices do not increase by a corresponding amount, the processor has to replace the British thermal units 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 nine percent of its gross margin and accounted for 44 percent of its natural gas processed volumes in 2011. 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 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 $2.50 per MMBtu level due to an oversupply of natural gas from shale play drilling activity. 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. In particular, certain states have adopted or are considering, and Congress is considering, adopting regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic fracturing operations or otherwise seek to ban fracturing activities altogether. In the event Federal, state, local or municipal legal restrictions are adopted in the areas where Enogex operates, there may be a delay or curtailment in drilling activities. 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.

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

The Company is exposed to changes in commodity prices in its operations. The Company primarily uses forward physical contracts, commodity price swap contracts and commodity price option features to manage the Company's commodity price risk exposures.

From time to time, Enogex has instituted a hedging program that was intended to reduce the commodity price risk associated with Enogex's keep-whole and percent-of-liquids arrangements. 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. To the extent Enogex hedges its commodity price and interest rate exposures, Enogex may 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 NGLs supply. In 2011, Chesapeake Energy Marketing Inc., Apache Corporation, Devon Energy Production Company, L.P., BP America Production Company and Kaiser Francis Oil Co. accounted for 55.4 percent of Enogex's natural gas and NGLs supply. The loss of the natural gas and NGLs 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 transportation customers are OG&E and PSO, the second largest electric utility in Oklahoma. 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. In 2011, 2010 and 2009, revenues from Enogex's firm intrastate transportation and storage contracts were $130.7 million, $116.6 million and $116.8 million, respectively, of which $47.5 million in each year was attributed to OG&E and $15.3 million in each year was attributed to PSO. 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. The stated term of the OG&E contract expired April 30, 2009, but the contract remains 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, 2012, the contract will remain in effect at least through April 30, 2013. 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.

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 a Pension Plan that covers substantially all of our employees hired before December 1, 2009. We also have defined benefit postretirement plans that cover substantially all of our employees hired prior to February 1, 2000. 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, 2011, we expect to continue to make future contributions to maintain required funding levels. It is our practice to also make voluntary contributions to maintain more prudent funding levels than minimally required. These amounts are estimates and may change based on actual stock market performance, changes in interest rates and any changes in governmental regulations.

All employees hired prior to February 1, 2000 participate in defined benefit 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 factors 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, 29 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, 2011, the Company and its subsidiaries had outstanding indebtedness and other liabilities of $6.1 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 as well as a Federal regulatory agency which generally possess broad powers to ensure that the needs of the utility customers are being met. To the extent that the state commissions or Federal regulatory agency 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 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.

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 you that any of our current credit 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 disruptions. Pricing grids associated with our credit facilities could cause annual fees and borrowing rates to increase if an adverse rating impact occurs. The impact of any future downgrade would include an increase in the costs of our short-term borrowings, but a reduction in our credit ratings would not result in any defaults or accelerations. Any future downgrade would also lead to higher long-term borrowing costs and, if below investment grade, could require us to post collateral or letters of credit.

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 12 generating stations with an aggregate capability of 6,790 MWs at December 31, 2011. The following tables set 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	2011 Capacity Factor (A)	Unit Capability (MW)	Station Capability (MW)
Seminole	1	1971	Steam-Turbine	Gas	Base Load	25.6%	490	
	1GT	1971	Combustion-Turbine	Gas	Peaking	0.2% (B)	16	
	2	1973	Steam-Turbine	Gas	Base Load	29.1%	499	
	3	1975	Steam-Turbine	Gas/Oil	Base Load	21.7%	496	1,501
Muskogee	4	1977	Steam-Turbine	Coal	Base Load	63.3%	504	
	5	1978	Steam-Turbine	Coal	Base Load	59.6%	500	
	6	1984	Steam-Turbine	Coal	Base Load	67.9%	506	1,510
Sooner	1	1979	Steam-Turbine	Coal	Base Load	69.0%	515	
	2	1980	Steam-Turbine	Coal	Base Load	74.0%	523	1,038
Horseshoe Lake	6	1958	Steam-Turbine	Gas/Oil	Base Load	14.0%	162	
	7	1963	Combined Cycle	Gas/Oil	Base Load	20.0%	225	
	8	1969	Steam-Turbine	Gas	Base Load	9.2%	380	
	9	2000	Combustion-Turbine	Gas	Peaking	5.4% (B)	46	
	10	2000	Combustion-Turbine	Gas	Peaking	6.1% (B)	46	859
Redbud (C)	1	2003	Combined Cycle	Gas	Base Load	41.6%	147	
	2	2003	Combined Cycle	Gas	Base Load	45.5%	149	
	3	2003	Combined Cycle	Gas	Base Load	47.8%	147	
	4	2003	Combined Cycle	Gas	Base Load	44.5%	146	589
Mustang	1	1950	Steam-Turbine	Gas	Peaking	6.5% (B)	50	
	2	1951	Steam-Turbine	Gas	Peaking	7.2% (B)	50	
	3	1955	Steam-Turbine	Gas	Base Load	23.3%	109	
	4	1959	Steam-Turbine	Gas	Base Load	22.7%	250	
	5A	1971	Combustion-Turbine	Gas/Jet Fuel	Peaking	2.4% (B)	32	
	5B	1971	Combustion-Turbine	Gas/Jet Fuel	Peaking	2.7% (B)	32	523
McClain (D)	1	2001	Combined Cycle	Gas	Base Load	70.1%	353	353
Woodward	1	1963	Combustion-Turbine	Gas	Peaking	—% (B)(E)	—	—
Enid	1	1965	Combustion-Turbine	Gas	Peaking	—% (B)(E)	—	
	2	1965	Combustion-Turbine	Gas	Peaking	—% (B)(E)	—	
	3	1965	Combustion-Turbine	Gas	Peaking	—% (B)(E)	—	
	4	1965	Combustion-Turbine	Gas	Peaking	—% (B)(E)	—	—
Total Generating Capability (all stations, excluding wind stations)								6,373

Station	Year Installed	Location	Number of Units	Fuel Capability	2011 Capacity Factor (A)	Unit Capability (MW)	Station Capability (MW)
Crossroads (F)	2011	Woodward, OK	85	Wind	45.9%	2.3	196
Centennial	2007	Woodward, OK	80	Wind	31.0%	1.5	120
OU Spirit	2009	Woodward, OK	44	Wind	37.8%	2.3	101
Total Generating Capability (wind stations)							417

(A) 2011 Capacity Factor = 2011 Net Actual Generation / (2011 Net Maximum Capacity (Nameplate Rating in MWs) x Period Hours (8,760 Hours)).
(B) Peaking units are used when additional short-term capacity is required.
(C) Represents OG&E's 51 percent ownership interest in the Redbud Plant.
(D) Represents OG&E's 77 percent ownership interest in the McClain Plant.
(E) This unit did not demonstrate summer capability in 2011 as prescribed by the SPP criteria.
(F) The Crossroads wind farm was fully in service in January 2012, which increased station capability to 227.5 MWs.

At December 31, 2011, OG&E's transmission system included: (i) 51 substations with a total capacity of 11.5 million kilovolt-amps and 4,258 structure miles of lines in Oklahoma and (ii) seven substations with a total capacity of 2.4 million kilovolt-amps and 279 structure miles of lines in Arkansas. OG&E's distribution system included: (i) 353 substations with a total capacity of 9.1 million kilovolt-amps, 27,854 structure miles of overhead lines, 1,895 miles of underground conduit and 10,120 miles of underground conductors in Oklahoma and (ii) 37 substations with a total capacity of 1.0 million kilovolt-amps, 2,250 structure miles of overhead lines, 212 miles of underground conduit and 572 miles of underground conductors in Arkansas.

OG&E owns 140,133 square feet of office space at its executive offices at 321 North Harvey, Oklahoma City, Oklahoma 73102. 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: (i) parcels that it owns in fee and (ii) 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 reflect names of 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, 2011, Enogex and its subsidiaries owned: (i) approximately 6,019 miles of intrastate natural gas gathering pipelines in Oklahoma and Texas; (ii) approximately 2,250 miles of intrastate natural gas transportation pipelines in Oklahoma; (iii) two underground natural gas storage facilities in Oklahoma operating at a combined working gas level of 24 billion cubic feet with 650 MMcf/d of maximum withdrawal capacity and 650 MMcf/d of injection capacity; (iv) 638,350 horsepower of owned compression and (v) eight operating natural gas processing plants, with a current total inlet capacity of 1,105 MMcf/d, 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	2011 Average Daily Inlet Volumes (MMcf/d)	Inlet Capacity (MMcf/d)
Calumet (A)	1969	Lean Oil	Gas/Electric	178	250
South Canadian (A) (B)	2011	Cryogenic	Electric	74	200
Cox City (C) (D)	1994	Cryogenic	Gas/Electric	155	180
Thomas (A)	1981	Cryogenic	Gas	132	135
Clinton (A)	2009	Cryogenic	Electric	122	120
Roger Mills (C)	2008	Refrigeration	Electric	29	100
Canute (C)	1996	Cryogenic	Electric	51	60
Wetumka (A)	1983	Cryogenic	Gas/Electric	37	60
Total				778	1,105

(A) These processing plants are located on property that Enogex owns in fee.
(B) This plant was placed into service in December 2011.
(C) These processing plants are located on easements or leased property as described above.
(D) On December 8, 2010, a fire occurred at Enogex's Cox City natural gas processing plant destroying major components of one of the four processing trains, representing 120 MMcf/d of the total 180 MMcf/d of capacity, at that facility. Gas volumes normally processed at the Cox City plant were diverted to other facilities or bypassed around Enogex's system to accommodate

production and all of the impacted gathered volumes were back online in December 2010. The damaged train was replaced and the facility was returned to full service in September 2011. Average daily inlet volumes were calculated using October through December 2011 inlet volumes.

On April 1, 2011, Enogex completed the sale of its Harrah processing plant (38MMcf/d of capacity) and the associated Wellston and Davenport gathering assets. The proceeds from the sale were $15.9 million and Enogex recorded a pre-tax gain in the second quarter of 2011 of $3.7 million.

Enogex also has a 50 percent interest in Atoka, which operated a 20 MMcf/d refrigeration processing plant which processed gas gathered in the Atoka area. The processing plant was leased on a month-to-month basis. In August 2011, management made a decision to use third-party processing exclusively for gathered volumes dedicated to Atoka and, therefore, to take the processing plant out of service and return it to the lessor in accordance with the rental agreement. See Note 5 of Notes to Consolidated Financial Statements for a further discussion.

Enogex currently occupies 116,184 square feet of office space at its executive offices at 515 Central Park Drive, Suite 110, Oklahoma City, Oklahoma 73105 under a lease that expires March 31, 2012. On June 30, 2011, Enogex executed a five-year lease agreement that expires March 31, 2017 for 134,219 square feet of office space at its new executive offices. Although Enogex may require additional office space as its business expands, Enogex believes that its new 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, 2011, the Company's gross property, plant and equipment (excluding construction work in progress) additions were $2.9 billion and gross retirements were $316.8 million. These additions were provided by cash generated from operations, 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 28.2 percent of gross property, plant and equipment (excluding construction work in progress) at December 31, 2011.

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. 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 GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. Except as set forth below and in Notes 16 and 17 of Notes to Consolidated Financial Statements, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

1. *Will Price, et al. v. El Paso Natural Gas Co., et al. (Price I).* On September 24, 1999, various subsidiaries of OGE Energy 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, OG&E and Enogex Inc. were omitted from the case but two of OGE Energy's other subsidiary entities remained as defendants. The plaintiffs' amended petition seeks class certification and alleges that 60 defendants, including two of OGE Energy's subsidiary entities, have improperly measured the volume of natural gas. The 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.

On September 18, 2009, the court entered its order denying class certification. On October 2, 2009, the plaintiffs filed for a rehearing of the court's denial of class certification. On March 31, 2010, the court denied the plaintiffs' request for rehearing. On July 20, 2011, Enogex LLC and OER filed motions for summary judgment. On January 25, 2012, the court denied portions of the motions for summary judgment related to the legal issue of the plaintiffs' claims regarding civil conspiracy. In an order dated January 23, 2012, the court granted the plaintiffs additional time to perform discovery prior to the consideration of the motions for summary judgment as they relate to the plaintiffs' other claims.

OGE Energy intends to vigorously defend this action. At this time, OGE Energy does not believe the outcome will have a material impact on its financial position.

2. *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 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 amended petition of the Price I case. OG&E and Enogex Inc. were not named in this case, but two of OGE Energy's other subsidiary entities were named in this case. The plaintiffs allege that the defendants mismeasured the British thermal unit 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.

On September 18, 2009, the court entered its order denying class certification. On October 2, 2009, the plaintiffs filed for a rehearing of the court's denial of class certification. On March 31, 2010, the court denied the plaintiffs' request for rehearing. On July 20, 2011, Enogex LLC and OER filed motions for summary judgment. On January 25, 2012, the court denied portions of the motions for summary judgment related to the legal issue of the plaintiffs' claims regarding civil conspiracy. In an order dated January 23, 2012, the court granted the plaintiffs additional time to perform discovery prior to the consideration of the motions for summary judgment as they relate to the plaintiffs' other claims.

OGE Energy intends to vigorously defend this action. At this time, OGE Energy does not believe the outcome will have a material impact on its financial position.

3. *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 alleged 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 asserted breach of contract, implied covenants, obligation, fiduciary duty, unjust enrichment, conspiracy and fraud causes of action and claim actual damages, plus attorneys' fees and costs, and punitive damages. 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 Company 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 America, Inc. and BP America Production Company's cross claim on January 16, 2007. On October 14, 2011, this case was dismissed without prejudice. While this lawsuit could be re-filed, Enogex considers the claims and cross claim associated with this lawsuit to be without merit, based upon Enogex's investigation to date. Enogex now considers this case closed.

4. *Opacity Notice.* On May 17, 2011, OG&E entered into a Consent Order with the ODEQ related to alleged violations of Federal and state opacity standards from 2005 to May 2011 at OG&E's Muskogee and Sooner generating stations. The Consent Order requires OG&E to reach certain milestones with regard to the overall amount of time when opacity exceeds certain amounts. Beginning January 1, 2015, the Consent Order requires each unit at OG&E's Muskogee and Sooner generating stations to have a rolling annual average of the time that opacity emissions are in excess of 20 percent to a level equal to or below one percent of the total time in a measurement period. OG&E agreed to implement two specific projects and other measures as necessary to achieve the milestones established in the Consent Order. These projects and other measures are not expected to involve significant capital or ongoing operating expenses. OG&E also agreed to pay a stipulated cash penalty of $150,000 and agreed to contribute another $150,000 to an ODEQ environmental fund for assisting small Oklahoma communities with their drinking water and wastewater treatment systems. OG&E entered into the Consent Order without admitting or denying the allegations made by the ODEQ. In order to facilitate the court approval of the Consent Order, the ODEQ initiated the necessary legal action against OG&E in state court on May 17, 2011. On June 2, 2011, the Consent Order was approved and entered by the District Court of Oklahoma County, Oklahoma. Subject to the ongoing compliance obligations described above pursuant to the Consent Order, OG&E considers this matter closed.

As previously reported, on March 18, 2011, the Gulf Coast Environmental Labor Coalition gave notice pursuant to the citizen suit provision of the Federal Clean Air Act that it intended to file a lawsuit against OG&E seeking both injunctive relief to enjoin excess opacity emissions from OG&E's Muskogee and Sooner generating stations and the assessment of civil penalties for alleged past violations of the applicable opacity limits. Because the Consent Order addresses the same alleged violations, the legal action by the ODEQ will prevent the Gulf Coast Environmental Labor Coalition from filing the lawsuit against OG&E. Neither the ODEQ action against OG&E in state court nor the Consent Order preclude the EPA from seeking additional relief in connection with the allegations of opacity emissions not in accordance with applicable new source performance standards that are contained in the previously disclosed notice of violation issued to OG&E on April 26, 2011.

5. *Patent Infringement Case.* On September 16, 2011, TransData, Inc., a Texas corporation, sued OG&E in the Western District of Oklahoma, accusing OG&E of infringing three of their U.S. patents by using OG&E's General Electric "smart" meters with Silver Spring Networks wireless modules. The complaint seeks a judgment of infringement, unspecified damages, a permanent injunction, costs and attorneys fees. OG&E was served with the complaint on September 21, 2011 and has notified both General Electric and Silver Springs Network of the lawsuit and its intent to seek indemnity from those companies for any damages that it may incur from this lawsuit. TransData, Inc. sought to consolidate its OG&E lawsuit with similar lawsuits in the Eastern District of Texas, however, on December 13, 2011, the TransData, Inc. cases were consolidated in the Western District of Oklahoma. OG&E has filed a motion for extension of time to answer the complaint. On December 30, 2011 OG&E and General Electric agreed to terms for General Electric to provide OG&E with an unqualified defense in the matter and to indemnify OG&E for costs, expenses and damages awarded against OG&E subject to a reservation of rights. While the Company cannot predict the outcome of this lawsuit at this time, the Company intends to vigorously defend this action and believes that its ultimate resolution will not be material to the Company's consolidated financial position or results of operations.

Item 4. Mine Safety Disclosures.

Not Applicable.

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.

		Price	
2012	Dividend Paid	High	Low
First Quarter (through February 10)	$ 0.3925	$ 57.54	$ 52.34
2011			
First Quarter	$ 0.3750	$ 50.61	$ 44.69
Second Quarter	0.3750	53.50	47.64
Third Quarter	0.3750	52.15	40.56
Fourth Quarter	0.3750	57.17	45.70
2010			
First Quarter	$ 0.3625	$ 39.32	$ 34.92
Second Quarter	0.3625	42.25	33.87
Third Quarter	0.3625	41.11	35.38
Fourth Quarter	0.3625	46.18	39.93

At the Company's December 2011 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 $0.3925 per share from $0.3750 per share effective with the Company's first quarter 2012 dividend.

The number of record holders of the Company's Common Stock at December 31, 2011, was 19,948. The book value of the Company's Common Stock at December 31, 2011, was $28.77.

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, and from distributions paid by Enogex Holdings, 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, the covenants of OG&E's certificate of incorporation and OG&E's debt instruments limiting the ability of OG&E to pay dividends and the ability of public utility commissions that regulate OG&E to effectively restrict the payment of dividends by OG&E. 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 LLC's debt instruments (including Enogex LLC's revolving credit agreement) limiting the ability of Enogex Holdings 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 common stock, premiums on common 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 currently restricted by these provisions.

Issuer Purchases of Equity Securities

The following table contains information about the Company's purchases of its common stock during the fourth quarter of 2011.

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
10/1/11 – 10/31/11	—	$ —	N/A	N/A
11/1/11 – 11/30/11	120,000	$ 51.33	120,000	N/A
12/1/11 – 12/31/11	—	$ —	N/A	N/A

N/A – not applicable

In November 2011, the Company purchased 120,000 shares of its common stock at an average cost of $51.33 per share on the open market. These shares will be used to satisfy Enogex's portion of the Company's obligation to deliver shares of common stock related to long-term incentive payouts of earned performance units in 2012.

Item 6. Selected Financial Data

HISTORICAL DATA

Year ended December 31	**2011**	2010	2009	2008	2007
SELECTED FINANCIAL DATA					
(In millions, except per share data)					
Results of Operations Data:					
Operating revenues	**$ 3,915.9**	$ 3,716.9	$ 2,869.7	$ 4,070.7	$ 3,797.6
Cost of goods sold	**2,277.9**	2,187.4	1,557.7	2,818.0	2,634.7
Gross margin on revenues	**1,638.0**	1,529.5	1,312.0	1,252.7	1,162.9
Operating expenses	**991.3**	935.6	820.1	790.6	707.6
Operating income	**646.7**	593.9	491.9	462.1	455.3
Interest income	**0.5**	—	1.4	6.7	2.1
Allowance for equity funds used during construction	**20.4**	11.4	15.1	—	—
Other income	**19.3**	13.7	27.5	15.4	17.4
Other expense	**21.7**	17.9	16.3	25.6	22.7
Interest expense	**140.9**	139.7	137.4	120.0	90.2
Income tax expense	**160.7**	161.0	121.1	101.2	116.7
Net income	**363.6**	300.4	261.1	237.4	245.2
Less: Net income attributable to noncontrolling interest	**20.7**	5.1	2.8	6.0	1.0
Net income attributable to OGE Energy	**$ 342.9**	$ 295.3	$ 258.3	$ 231.4	$ 244.2
Basic earnings per average common share attributable to OGE Energy common shareholders	**$ 3.50**	$ 3.03	$ 2.68	$ 2.50	$ 2.66
Diluted earnings per average common share attributable to OGE Energy common shareholders	**$ 3.45**	$ 2.99	$ 2.66	$ 2.49	$ 2.64
Dividends declared per common share	**$ 1.5175**	$ 1.4625	$ 1.4275	$ 1.3975	$ 1.3675
Balance Sheet Data (at period end):					
Property, plant and equipment, net	**$ 7,474.0**	$ 6,464.4	$ 5,911.6	$ 5,249.8	$ 4,246.3
Total assets	**$ 8,906.0**	$ 7,669.1	$ 7,266.7	$ 6,518.5	$ 5,237.8
Long-term debt	**$ 2,737.1**	$ 2,362.9	$ 2,088.9	$ 2,161.8	$ 1,344.6
Total stockholders' equity	**$ 2,819.3**	$ 2,400.0	$ 2,060.8	$ 1,914.0	$ 1,691.6
Capitalization Ratios (A)					
Stockholders' equity	**50.7%**	50.4%	46.4%	47.0%	55.7%
Long-term debt	**49.3%**	49.6%	53.6%	53.0%	44.3%
Ratio of Earnings to Fixed Charges (B)					
Ratio of earnings to fixed charges	**4.12**	4.02	3.38	3.55	4.66

(A) Capitalization ratios = [Total stockholders' equity / (Total stockholders' equity + Long-term debt + Long-term debt due within one year)] and [(Long-term debt + Long-term debt due within one year) / (Total stockholders' equity + Long-term debt + Long-term debt due within one year)].

(B) For purposes of computing the ratio of earnings to fixed charges, (i) earnings consist of pre-tax income plus fixed charges, less allowance for borrowed funds used during construction and other capitalized interest and (ii) 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

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 OG&E and are subject to regulation by the OCC, the APSC and the 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 natural gas business in 1928 and is no longer engaged in the natural gas distribution business.

Enogex is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting, storing and marketing natural gas. Most of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex's operations are organized into three business segments: (i) natural gas transportation and storage, (ii) natural gas gathering and processing and (iii) natural gas marketing. At December 31, 2011, the Company indirectly owns an 81.3 percent membership interest in Enogex Holdings, which in turn owns all of the membership interests in Enogex LLC.

Overview

Company Strategy

The Company's mission 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's corporate strategy is to continue to maintain its existing business mix and diversified asset position of its regulated electric utility business and unregulated natural gas midstream business while providing competitive energy products and services to customers primarily in the south central United States as well as seeking growth opportunities in both businesses. Additionally, the Company wants to achieve a premium valuation of its businesses relative to its peers, grow earnings per share with a stable earnings pattern, create a high performance culture and achieve desired outcomes with target stakeholders.

OG&E is focused on increased investment to preserve system reliability and meet load growth by adding and maintaining infrastructure equipment and replacing aging transmission and distribution systems. OG&E is focused on maintaining strong regulatory and legislative relationships for the long-term benefit of its customers. In an effort to encourage more efficient use of electricity, OG&E is also providing energy management solutions to its customers through the Smart Grid program that utilizes newer technology to improve operational and environmental performance and promote demand-side management programs. If these initiatives are successful, OG&E believes it may be able to defer the construction or acquisition of any incremental fossil fuel generation capacity until 2020. As the Smart Grid platform matures, OG&E anticipates providing new products and services to its customers. In addition, OG&E is also pursuing additional transmission-related opportunities within the SPP. OG&E is customer focused and strives to provide excellent customer service.

Enogex's business plan entails growing its businesses and providing attractive financial returns through efficient operations and effective commercial management of its assets, capturing growth opportunities through expansion projects, increased utilization of existing assets and through acquisitions in and around its footprint. In addition, Enogex is seeking to geographically diversify its gathering, processing and transportation businesses principally by expanding into other areas that are complementary with the Company's capabilities. Enogex expects to accomplish this diversification by undertaking organic growth projects and through acquisitions.

The Company's financial objectives include a long-term annual earnings growth rate of five to seven percent on a weather-normalized basis, maintaining a strong credit rating as well as increasing the dividend to meet the Company's dividend payout objectives. The Company's target payout ratio is to pay out dividends no more than 60 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 the Company's shareholder base, the Company's financial position, the Company's growth targets, the composition of the Company's assets and investment opportunities. The Company believes it can accomplish these financial objectives 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.

Summary of Operating Results

2011 compared to 2010. Net income attributable to OGE Energy was $342.9 million, or $3.45 per diluted share, in 2011 as compared to $295.3 million, or $2.99 per diluted share, in 2010. Included in net income attributable to OGE Energy in 2010 was a one-time, non-cash charge of $11.4 million, or $0.11 per diluted share, related to the elimination of the tax deduction for the Medicare Part D subsidy (as previously reported in the Company's Form 10-Q for the quarter ended March 31, 2011). The increase in net income attributable to OGE Energy of $47.6 million, or 16.1 percent, or $0.46 per diluted share, in 2011 as compared to 2010 was primarily due to:

- an increase in net income at OG&E of $47.6 million, or 22.1 percent, or $0.47 per diluted share of the Company's common stock, primarily due to a higher gross margin primarily from warmer weather in OG&E's service territory partially offset by higher other operation and maintenance expense, higher interest expense and higher income tax expense. Income tax expense was higher due to higher pre-tax income which more than offset the effects of the Medicare Part D subsidy discussed above;
- a decrease in net income at Enogex of $8.9 million, or 9.8 percent, or $0.09 per diluted share of the Company's common stock, primarily due to higher other operation and maintenance expense and the equity sale of a membership interest in Enogex Holdings to the ArcLight group partially offset by a higher gross margin primarily from increased gathered volumes associated with ongoing expansion projects and higher NGLs prices, the recognition of a gain related to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets, lower interest expense and lower income tax expense related to the Medicare Part D subsidy discussed above; and
- an increase in net income at OGE Energy of $8.9 million, or 77.4 percent, or $0.08 per diluted share of the Company's common stock, primarily due to lower other operation and maintenance expense, a decrease in charitable contributions in 2011 and a higher income tax benefit related to the Medicare Part D subsidy discussed above.

Timing Item. Enogex's net income in 2011 was $82.2 million, which included a loss of $2.6 million resulting from recording OER's natural gas storage inventory at the lower of cost or market value. The offsetting gains from the sale of withdrawals from inventory are expected to be realized during the first quarter of 2012.

2010 compared to 2009. Net income attributable to OGE Energy was $295.3 million, or $2.99 per diluted share, in 2010 as compared to $258.3 million, or $2.66 per diluted share, in 2009. Included in net income attributable to OGE Energy in 2010 was a one-time, non-cash charge of $11.4 million, or $0.11 per diluted share, related to the elimination of the tax deduction for the Medicare Part D subsidy (as previously reported in the Company's Form 10-Q for the quarter ended March 31, 2011). The increase in net income attributable to OGE Energy of $37.0 million, or 14.3 percent, or $0.33 per diluted share, in 2010 as compared to 2009 was primarily due to:

- an increase in net income at OG&E of $15.3 million or 7.6 percent, or $0.12 per diluted share of the Company's common stock, due to a higher gross margin primarily due to rate increases and riders and warmer weather in OG&E's service territory partially offset by higher other operation and maintenance expense, higher depreciation and amortization expense and higher income tax expense mainly attributable to higher pre-tax income and the elimination of the tax deduction for the Medicare Part D subsidy discussed above;
- an increase in net income at Enogex of $29.8 million or 48.6 percent, or $0.29 per diluted share of the Company's common stock, due to a higher gross margin primarily due to higher processing spreads, higher NGLs prices, higher natural gas prices and increased volumes partially offset by higher other operation and maintenance expense and higher income tax expense mainly attributable to higher pre-tax income and the elimination of the tax deduction for the Medicare Part D subsidy discussed above; and
- an increase in the net loss at OGE Energy of $8.1 million, or $0.08 per diluted share of the Company's common stock, due to higher other expense primarily attributable to an increase in charitable contributions to OGE Energy's charitable giving foundation in 2010 and higher income tax expense mainly attributable to the elimination of the tax deduction for the Medicare Part D subsidy discussed above partially offset by lower interest expense primarily due to lower average commercial paper borrowings and a lower average interest rate in 2010.

Recent Developments and Regulatory Matters

Global Climate Change, Environmental Concerns and Related Opportunities

It is uncertain at this time whether, and in what form, Congress will adopt legislation to restrict greenhouse gas emissions. In the absence of such legislation, the EPA has taken steps to regulate greenhouse gas emissions. Future legislation or rules could require reductions of carbon dioxide and other greenhouse gas emissions from generation facilities. This could result in significant changes to the Company's operations, significant capital expenditures by the Company and a significant increase in the Company's cost of conducting business. The OG&E service territory is in central Oklahoma and borders one of the nation's best wind resource areas. Uncertainty surrounding global climate change and environmental concerns related to new coal-fired generation development is changing the mix of the potential sources of new generation in the region. Adoption of renewable portfolio standards would be expected to increase the region's reliance on wind generation and other renewables. The Company has leveraged its advantageous geographic position to develop renewable energy resources and transmission to deliver the renewable energy. In January 2012, the Crossroads wind farm was placed in service and added to OG&E's wind power portfolio, which now includes potential wind generation of up to of 780 MWs (including wind power purchase agreements). In addition, the SPP regional transmission organization has begun to address the relative lack of transmission lines capable of bringing renewable energy out of the wind resource area in western Oklahoma, the Texas panhandle and western Kansas to load centers by planning for more transmission to be built in the area. In addition to significantly increasing overall system reliability, these new transmission resources should provide greater access to additional wind resources that are currently constrained due to existing transmission delivery constraints.

OG&E Crossroads Wind Farm

On July 29, 2010, OG&E received an order from the OCC authorizing OG&E to recover from Oklahoma customers the cost to construct Crossroads, with the rider being implemented as the individual turbines are placed in service. The Crossroads wind farm was fully in service in January 2012. As part of this project, on June 16, 2011, OG&E entered into an interconnection agreement with the SPP for Crossroads which allowed Crossroads to interconnect at 227.5 MWs.

OG&E 2011 Oklahoma Rate Case Filing

As part of the Joint Stipulation and Settlement Agreement reached in OG&E's 2009 Oklahoma rate case filing, the parties agreed that OG&E would file a rate case on or before June 30, 2011. On May 27, 2011, OG&E requested an extension until the end of July 2011 for filing the Oklahoma rate case. On July 28, 2011, OG&E filed its application with the OCC requesting an annual rate increase of $73.3 million, or a 4.3 percent increase in its rates. OG&E is requesting a return on equity of 11.00 percent based on a common equity percentage of 53 percent. Each 0.10 percent change in the requested return on equity affects the requested rate increase by $3.0 million. In its application, OG&E seeks to recover increases in its operating costs and to begin earning on approximately $500 million of new capital investments made on behalf of its Oklahoma customers during the previous two and one-half years. On November 9, 2011, the OCC Staff recommended a $6.2 million annual rate decrease based on a return on equity of 9.81 percent and a common equity percentage of 53 percent. The staff of the Oklahoma Attorney General recommended a return on equity of 9.818 percent and a common equity percentage of 49.5 percent. The staff of the Oklahoma Attorney General did not recommend a specific revenue requirement, but OG&E believes that adoption of the staff of the Oklahoma Attorney General's recommendations would result in a rate decrease. The Oklahoma Industrial Electric Consumers recommended a $56 million annual rate decrease based on a return on equity of 9.5 percent and a common equity percentage of 48 percent. OG&E filed rebuttal testimony on November 29, 2011 on the revenue requirement testimony filed by the parties on November 9, 2011. On November 16, 2011, the parties filed cost-of-service and rate design testimony and OG&E filed rebuttal testimony in those areas on December 2, 2011. The hearing in this matter began on December 13, 2011. OG&E expects to receive an order from the OCC in the first quarter of 2012.

OG&E Contract and Wind Energy Purchase Agreement Filing

On December 1, 2011, OG&E filed an application with the OCC requesting approval of a 20-year agreement that is intended to provide wind power to help meet the current and future power generation needs of Oklahoma State University. The project calls for OG&E to contract with NextEra Energy to build a 60 MW wind farm near Blackwell, Oklahoma, to support the Oklahoma State University project in which NextEra will build, own and operate the wind farm and OG&E will purchase the electric output. A procedural schedule has not yet been established in this matter. OG&E expects to receive a decision from the OCC in the first quarter of 2012.

Enogex FERC Section 311 2009 Rate Case

On March 27, 2009, Enogex filed a petition for rate approval with the FERC to set the maximum rates for its new firm East Zone Section 311 transportation service and to revise the rates for its existing East and West Zone interruptible Section 311 transportation service. In anticipation of offering this new service, Enogex had filed with the FERC, as required by the FERC's regulations, a revised Statement of Operating Conditions Applicable to Transportation Services to describe the terms, conditions and operating arrangements for the new service. Enogex made the Statement of Operating Conditions filing on February 27, 2009. Enogex began offering firm East Zone Section 311 transportation service on April 1, 2009. The revised East and West Zone zonal rates for the Section 311 interruptible transportation service became effective June 1, 2009. The rates for the firm East Zone Section 311 transportation service and the increase in the rates for East and West Zone and interruptible Section 311 service were collected, subject to refund, pending the FERC approval of the proposed rates. A number of parties intervened in both the rate case and the Statement of Operating Conditions filing and some additionally filed protests. On January 4, 2010, the FERC Staff submitted an offer proposing various adjustments to Enogex's filed cost of service. On April 27, 2010, Enogex submitted comments to the FERC Staff stating that it would agree to the offer, contingent upon all parties agreeing to support or not oppose. On October 4, 2011, Enogex filed a settlement agreement with the FERC which included a proposed refund to shippers of $2.1 million related to the increase in the rates for East and West Zone and interruptible Section 311 service which were collected, subject to refund, pending the FERC approval of the proposed rates. This refund was made to shippers in January 2012. On December 16, 2011, the FERC issued an order approving the settlement agreement. See Note 17 of Notes to Consolidated Financial Statements for a further discussion.

Enogex Cox City Plant Fire

On December 8, 2010, a fire occurred at Enogex's Cox City natural gas processing plant destroying major components of one of the four processing trains, representing 120 MMcf/d of the total 180 MMcf/d of capacity, at that facility. Gas volumes normally processed at the Cox City plant were diverted to other facilities or bypassed around Enogex's system to accommodate production and all of the impacted gathered volumes were back online in December 2010. The damaged train was replaced and the facility was returned to full service in September 2011. The total cost necessary to return the facility back to full service was $29.6 million. While Enogex believes that the costs in excess of the $10 million deductible should be reimbursed by insurance, the matter is currently being negotiated with the insurance company and Enogex cannot predict the precise outcome of these negotiations or the timing associated with the recovery. In the fourth quarter of 2011, Enogex received a partial insurance reimbursement of $7.4 million and recognized a gain of $3.0 million on insurance proceeds. Enogex expects to receive additional reimbursement of portions of the costs in 2012. Enogex will recognize insurance recoveries in earnings as the insurance claims are resolved.

Enogex Contract Conversion

In August 2011, Enogex and one of its five largest customers entered into new agreements, effective July 1, 2011, relating to the customer's gathering and processing volumes on the Oklahoma portion of Enogex's system. The effect of this new arrangement is that (i) the acreage dedicated by the customer to Enogex for gathering and processing in Oklahoma has been increased for an extended term and (ii) the processing arrangement has been converted from keep-whole to fixed fee. This customer's converted volumes represented 8.4 percent of total inlet volumes from July 1, 2011 to December 31, 2011. Also, as a result of this transaction and as part of the new agreements, Enogex recorded $6.4 million in Deferred Revenues on the Company's Consolidated Balance Sheet at December 31, 2011. Processing revenues under the agreements are recognized based on the estimated average fee per MMBtu processed over the life of the agreements. Enogex expects to record additional deferred revenues during 2012.

Enogex Western Oklahoma / Texas Panhandle Gathering and Processing System Expansions

As previously reported, gathering and processing volumes grew at a slower pace during the fourth quarter of 2011 than Enogex had anticipated. Enogex currently expects that this slower growth will continue during 2012. Despite this slower volume growth, Enogex still anticipates the need for additional processing capacity.

Enogex constructed a new 200 MMcf/d cryogenic processing plant in Canadian County, Oklahoma. The new plant, which has inlet and residue compression and is supported by the installation of 31 miles of 20-inch gathering pipeline, as well as 11 miles of 24-inch transmission pipeline providing takeaway capacity from the plant tailgate, was placed in service in December 2011. The total capital expenditures associated with this project were $140 million.

Enogex expects to expand its cryogenic processing plant currently under construction in Wheeler County, Texas from a processing capacity of 120 MMcf/d to 200 MMcf/d with the installation of additional residue compression facilities. The initial processing capacity of 120 MMcf/d is expected to be in service at the beginning of the third quarter of 2012, and the additional processing capacity is expected to be in service by the end of the third quarter of 2012. The new plant will be supported by the installation of 9,400 horsepower of field compression. The total capital expenditures associated with this project are expected to be $140 million.

In support of significant long-term acreage dedications from its customers in the area, Enogex continues to expand its gathering infrastructure in four counties of western Oklahoma. These expansions are planned to occur in phases, with the initial phase calling for the installation of 47,980 horsepower of low pressure compression and over 300 miles of gathering pipe across the area. This infrastructure is expected to be constructed throughout 2012 and 2013. The total capital expenditures associated with these expansions projects are expected to be $240 million.

Enogex expects to install a 200 MMcf/d cryogenic processing plant in Custer County, Oklahoma. The new plant will be supported by 6,000 horsepower of inlet compression and 25 miles of transmission pipeline. This plant is expected to be in service by the end of the third quarter of 2013. The total capital expenditures associated with this project are expected to be $135 million.

Gas Gathering Acquisitions

On September 23, 2011, Enogex entered into the following agreements: an agreement with Cordillera, Oxbow and West Canadian Midstream LLC pursuant to which Enogex agreed to acquire 100 percent of the membership interest in Roger Mills Gas Gathering, LLC, an Oklahoma limited liability company that owns an approximately 60-mile natural gas gathering system located in Roger Mills County and Ellis County, Oklahoma; an agreement with Cordillera and Oxbow pursuant to which Enogex agreed to acquire an approximately 30-mile natural gas gathering system located in Roger Mills County, Oklahoma; and agreements with Cordillera and other producers pursuant to which such producers agreed to provide Enogex with long-term acreage dedication in the area served by the gathering systems encompassing approximately 100,000 net acres. The gathering systems are located in the Granite Wash area. The aggregate purchase price for these transactions was $200.4 million which was paid in cash primarily from contributions from OGE Energy and the ArcLight group (as discussed in Note 4 of Notes to Consolidated Financial Statements) as well as cash generated from operations and bank borrowings. The transactions closed on November 1, 2011. Enogex believes that the transactions will provide Enogex with key new opportunities in the Granite Wash area. See Note 3 of Notes to Consolidated Financial Statements for a further discussion.

In support of the acquisitions described above, Enogex plans to construct 20 miles of 16-inch gathering pipe and over 11,000 horsepower of low pressure compression in 2012. The total capital expenditures for these projects are expected to be $55 million.

2012 Outlook

The Company's 2012 consolidated earnings guidance will be provided following a final order in the Oklahoma general rate case. The Company anticipates the final order during March 2012. The 2012 earnings guidance for Enogex and the related key assumptions for such guidance, as well as 2013 volume projections, are listed below.

2012 Earnings Guidance and Key Assumptions for Enogex:

The Company projects Enogex to earn approximately $80 million to $95 million, or $0.80 to $0.95 per average diluted share, in 2012 net of noncontrolling interest. The guidance assumes approximately 99.9 million average diluted shares outstanding. The key factors and assumptions include:

- Total Enogex anticipated gross margin of between $500 million and $515 million. The gross margin assumption includes:
  - Transportation, storage and marketing gross margin contribution of between $140 million and $155 million, of which 80 percent is attributable to the transportation business;
  - Gathering and processing gross margin contribution of between $355 million and $365 million, of which 62 percent is attributable to the processing business;
  - Key factors affecting the gathering and processing gross margin forecast are:
    - Assumed increase of six to 10 percent in gathered volumes over 2011;
    - Assumed increase of approximately 15 percent in processable* volumes over 2011;
    - At the midpoint of Enogex's gathering and processing assumption Enogex has assumed:
      - Processing contract mix of 42 percent fixed-fee, 25 percent percent-of-liquids, 17 percent percent-of-proceeds and 16 percent keep-whole;
      - Weighted average natural gas price of $2.70 per MMBtu in 2012;
      - Realized weighted average NGLs price of $1.04 per gallon in 2012; and

- Average price per gallon of condensate of $2.12 in 2012;
- Enogex has assumed operating expenses of $295 million to $305 million, with operation and maintenance expenses comprising 58 percent of the total;
- Interest expense of $31 million to $33 million;
- An effective tax rate of 38 percent; and
- ArcLight group will own approximately 19 percent of Enogex Holdings by the end of 2012.

2013 Volume Projections for Enogex:

- Assumed increase of 10 to 15 percent in gathered volumes over 2012; and
- Assumed increase of approximately 15 percent in processable* volumes over 2012.

***** Processable volumes include condensate volumes which are captured in the gathering pipeline and therefore not included in plant inlet volumes.

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, 2011, 2010 and 2009 and the Company's consolidated financial position at December 31, 2011 and 2010. 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)*	**2011**	2010	2009
Operating income	**$ 646.7**	$ 593.9	$ 491.9
Net income attributable to OGE Energy	**$ 342.9**	$ 295.3	$ 258.3
Basic average common shares outstanding	**97.9**	97.3	96.2
Diluted average common shares outstanding	**99.2**	98.9	97.2
Basic earnings per average common share attributable to OGE Energy common shareholders	**$ 3.50**	$ 3.03	$ 2.68
Diluted earnings per average common share attributable to OGE Energy common shareholders	**$ 3.45**	$ 2.99	$ 2.66
Dividends declared per common share	**$ 1.5175**	$ 1.4625	$ 1.4275

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)*	**2011**	2010	2009
OG&E (Electric Utility)	**$ 472.3**	$ 413.7	$ 354.1
Enogex (Natural Gas Midstream Operations)			
Transportation and storage	**74.4**	72.6	85.7
Gathering and processing	**118.7**	123.9	60.2
Marketing	**(18.1)**	(15.0)	(7.5)
Other Operations (A)	**(0.6)**	(1.3)	(0.6)
Consolidated operating income	**$ 646.7**	$ 593.9	$ 491.9

(A) 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.

OG&E (Electric Utility)

Year ended December 31 *(Dollars in millions)*	**2011**	2010	2009
Operating revenues	**$ 2,211.5**	$ 2,109.9	$ 1,751.2
Cost of goods sold	**1,013.5**	1,000.2	796.3
Gross margin on revenues	**1,198.0**	1,109.7	954.9
Other operation and maintenance	**436.0**	418.1	348.0
Depreciation and amortization	**216.1**	208.7	187.4
Impairment of assets	**—**	—	0.3
Taxes other than income	**73.6**	69.2	65.1
Operating income	**472.3**	413.7	354.1
Interest income	**0.5**	0.1	1.1
Allowance for equity funds used during construction	**20.4**	11.4	15.1
Other income	**8.0**	6.5	20.4
Other expense	**8.4**	1.6	6.7
Interest expense	**111.6**	103.4	93.6
Income tax expense	**117.9**	111.0	90.0
Net income	**$ 263.3**	$ 215.7	$ 200.4
Operating revenues by classification			
Residential	**$ 943.5**	$ 894.8	$ 717.9
Commercial	**531.3**	521.0	439.8
Industrial	**216.0**	212.5	172.1
Oilfield	**165.1**	162.8	132.6
Public authorities and street light	**207.4**	200.8	167.7
Sales for resale	**65.3**	65.8	53.6
Provision for rate refund	**—**	—	(0.6)
System sales revenues	**2,128.6**	2,057.7	1,683.1
Off-system sales revenues	**36.2**	21.7	31.8
Other	**46.7**	30.5	36.3
Total operating revenues	**$ 2,211.5**	$ 2,109.9	$ 1,751.2
MWH sales by classification *(In millions)*			
Residential	**9.9**	9.6	8.7
Commercial	**6.9**	6.7	6.4
Industrial	**3.9**	3.8	3.6
Oilfield	**3.2**	3.1	2.9
Public authorities and street light	**3.2**	3.0	3.0
Sales for resale	**1.4**	1.4	1.3
System sales	**28.5**	27.6	25.9
Off-system sales	**1.0**	0.5	1.0
Total sales	**29.5**	28.1	26.9
Number of customers	**789,146**	782,558	776,550
Weighted-average cost of energy per kilowatt-hour - cents			
Natural gas	**4.328**	4.638	3.696
Coal	**2.064**	1.911	1.747
Total fuel	**2.897**	3.012	2.474
Total fuel and purchased power	**3.215**	3.309	2.760
Degree days (A)			
Heating - Actual	**3,359**	3,528	3,456
Heating - Normal	**3,631**	3,631	3,631
Cooling - Actual	**2,776**	2,328	1,860
Cooling - Normal	**1,911**	1,911	1,911

(A) 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.

2011 compared to 2010. OG&E's operating income increased $58.6 million, or 14.2 percent, in 2011 as compared to 2010 primarily due to a higher gross margin partially offset by higher other operation and maintenance expense.

Gross Margin

Gross margin was $1,198.0 million in 2011 as compared to $1,109.7 million in 2010, an increase of $88.3 million, or 8.0 percent. The gross margin increased primarily due to:

- warmer weather in OG&E's service territory, which increased the gross margin by $27.4 million;
- increased price variance, which included revenues from various rate riders, including the Windspeed transmission line rider, the Oklahoma demand program rider, the Smart Grid rider, the system hardening rider, the Oklahoma storm recovery rider, the Crossroads rider and the OU Spirit rider, and higher revenues from sales and customer mix, which increased the gross margin by $23.9 million;
- higher transmission revenue primarily due to the inclusion of construction work in progress in transmission rates for specific FERC approved projects that previously accrued allowance for funds used during construction, which increased the gross margin by $15.3 million;
- new customer growth in OG&E's service territory, which increased the gross margin by $13.1 million;
- revenues from the Arkansas rate increase, which increased the gross margin by $6.0 million;
- higher demand and related revenues by non-residential customers in OG&E's service territory, which increased the gross margin by $5.0 million; and
- higher revenues related to the renewal of the Arkansas Valley Electric Cooperative contract (see Note 17 of Notes to Consolidated Financial Statements), which increased the gross margin by $3.1 million.

These increases in the gross margin were partially offset by a credit to customers related to the settlement of OG&E's 2009 fuel adjustment clause review (see Note 17 of Notes to Consolidated Financial Statements), which decreased the gross margin by $5.7 million.

Cost of goods sold for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was $775.0 million in 2011 as compared to $771.0 million in 2010, an increase of $4.0 million, or 0.5 percent, primarily due to higher generation primarily due to warmer weather in OG&E's service territory. 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 2011, OG&E's fuel mix was 58 percent coal, 39 percent natural gas and three percent wind. In 2010, OG&E's fuel mix was 55 percent coal, 42 percent natural gas and three percent wind. Purchased power costs were $230.7 million in 2011 as compared to $226.5 million in 2010, an increase of $4.2 million, or 1.9 percent, primarily due to an increase in short-term power purchases partially offset by a decrease in purchases in the energy imbalance service market and a decrease in cogeneration cost.

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 $436.0 million in 2011 as compared to $418.1 million in 2010, an increase of $17.9 million, or 4.3 percent. The increase in other operation and maintenance expenses was primarily due to:

- an increase of $15.5 million allocated from the holding company primarily related to payroll and benefits expense, contract technical and construction services and contract professional services;
- an increase of $12.1 million in salaries and wages expense primarily due to salary increases in 2011, increased incentive compensation expense and increased overtime expense primarily due to storms in April and August 2011;
- an increase of $4.6 million in other marketing and sales expense related to demand-side management initiatives, which expenses are being recovered through a rider;
- an increase of $3.1 million in uncollectible expense;
- an increase of $1.6 million in fleet transportation expense primarily due to higher fuel costs in 2011;
- an increase of $1.3 million in temporary labor expense; and
- an increase of $1.2 million in SPP administration fees.

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

- a decrease of $9.8 million in employee benefits expense primarily due to a decrease in postretirement benefits expense related to amendments to the Company's retiree medical plan adopted in January 2011 (see Note 14 of Notes to Consolidated Financial Statements) partially offset by a modification to OG&E's pension tracker and a decrease in worker's compensation accruals in 2011;
- a decrease of $5.0 million in injuries and damages expense primarily due to higher reserves on claims in 2010; and
- a decrease of $2.9 million related to decreased spending on vegetation management partially related to system hardening, which expenses are being recovered through a rider.

Additional Information

Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction was $20.4 million in 2011 as compared to $11.4 million in 2010, an increase of $9.0 million, or 78.9 percent, primarily due to higher levels of construction costs for Crossroads.

Other Income. Other income was $8.0 million in 2011 as compared to $6.5 million in 2010, an increase of $1.5 million, or 23.1 percent. The increase in other income was primarily due to a benefit of $5.6 million associated with the tax gross-up of allowance for equity funds used during construction partially offset by increased losses of $4.2 million recognized in the guaranteed flat bill program in 2011 from higher than expected usage resulting from warmer weather.

Other Expense. Other expense was $8.4 million in 2011 as compared to $1.6 million in 2010, an increase of $6.8 million, primarily due to an increase in charitable contributions of $6.4 million as the holding company made the charitable contributions in 2010.

Interest Expense. Interest expense was $111.6 million in 2011 as compared to $103.4 million in 2010, an increase of $8.2 million, or 7.9 percent, primarily due to a $14.0 million increase related to the issuance of long-term debt in June 2010 and May 2011. This increase in interest expense was partially offset by:

- a $4.9 million decrease in interest expense due to a higher allowance for borrowed funds used during construction primarily due to construction costs for Crossroads; and
- a $1.4 million decrease in interest expense in 2011 due to interest to customers related to the fuel over recovery balance in 2010.

Income Tax Expense. Income tax expense was $117.9 million in 2011 as compared to $111.0 million in 2010, an increase of $6.9 million, or 6.2 percent. The increase in income tax expense was primarily due to higher pre-tax income in 2011 as compared to 2010. This increase in income tax expense was partially offset by:

- the one-time, non-cash charge in 2010 for the elimination of the tax deduction for the Medicare Part D subsidy;
- the write-off of previously recognized Oklahoma investment tax credits in 2010 primarily due to expenditures no longer eligible for the Oklahoma investment tax credit related to the change in the tax method of accounting for capitalization of repair expenditures; and
- higher Oklahoma investment tax credits in 2011 as compared to 2010.

2010 compared to 2009. OG&E's operating income increased $59.6 million, or 16.8 percent, in 2010 as compared to 2009 primarily due to a higher gross margin partially offset by higher other operation and maintenance expense and higher depreciation and amortization expense.

Gross Margin

Gross margin was $1,109.7 million in 2010 as compared to $954.9 million in 2009, an increase of $154.8 million, or 16.2 percent. The gross margin increased primarily due to:

- increased price variance, which included revenues from various rate riders, including the Windspeed rider, the OU Spirit rider, the Oklahoma demand program rider and the Smart Grid rider, and higher revenues from the sales and customer mix, which increased the gross margin by $74.5 million;
- warmer weather in OG&E's service territory resulting in a 25 percent increase in cooling degree days, which increased the gross margin by $46.8 million;

- revenue from the full year effect of the August 2009 Oklahoma rate increase, which increased the gross margin by $24.1 million;
- higher demand and related revenues by non-residential customers in OG&E's service territory, which increased the gross margin by $6.9 million;
- new customer growth in OG&E's service territory, which increased the gross margin by $6.7 million; and
- revenues from the full year effect of the June 2009 Arkansas rate increase, which increased the gross margin by $3.5 million.

These increases in the gross margin were partially offset by lower other revenues due to fewer transmission requests from others on OG&E's system, which decreased the gross margin by $7.7 million.

Fuel expense was $771.0 million in 2010 as compared to $618.5 million in 2009, an increase of $152.5 million, or 24.7 percent, primarily due to higher natural gas prices and increased natural gas generation due to ongoing maintenance at some of OG&E's coal-fired power plants. 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 2010, OG&E's fuel mix was 55 percent coal, 42 percent natural gas and three percent wind. In 2009, OG&E's fuel mix was 60 percent coal, 38 percent natural gas and two percent wind. Purchased power costs were $226.5 million in 2010 as compared to $176.6 million in 2009, an increase of $49.9 million, or 28.3 percent, primarily due to an increase in purchases in the energy imbalance service market to meet OG&E's generation load requirements and an increase in short-term power agreements resulting in short-term spot market purchases.

Operating Expenses

Other operation and maintenance expenses were $418.1 million in 2010 as compared to $348.0 million in 2009, an increase of $70.1 million, or 20.1 percent. The increase in other operation and maintenance expenses was primarily due to:

- an increase of $16.2 million in contract technical and construction services and an increase of $5.2 million in materials and supplies expense primarily attributable to increased spending for ongoing maintenance at some of OG&E's power plants in 2010 as compared to 2009;
- an increase of $16.2 million in employee benefits expense primarily due to an increase in postretirement benefits due to an increase in medical costs and changes in actuarial assumptions in 2010, a reclassification in May 2009 of 2006 and 2007 pension settlement costs to a regulatory asset, as prescribed in the Arkansas rate case settlement, and an increase in pension expense due to an increase in the amount deferred as a pension regulatory liability in OG&E's Oklahoma jurisdiction resulting from OG&E's 2009 Oklahoma rate case;
- an increase of $9.7 million in allocations from the holding company primarily due to higher contract professional services expense, materials and supplies expense and communication and media services expense;
- an increase of $9.1 million in other marketing and sales expense related to demand-side management initiatives, which expenses are being recovered through a rider;
- an increase of $7.5 million in salaries and wages expense primarily due to salary increases in 2010;
- an increase of $4.8 million due to increased spending on vegetation management related to system hardening, which expenses are being recovered through a rider;
- an increase of $3.4 million in injuries and damages expense primarily due to increased reserves on claims in 2010;
- an increase of $2.1 million in overtime expense due to the storms in January and May 2010; and
- an increase of $1.7 million in temporary labor expense.

These increases in other operation and maintenance expenses were partially offset by a decrease of $3.9 million in incentive compensation expense primarily due to lower accruals in 2010.

Depreciation and amortization expense was $208.7 million in 2010 as compared to $187.7 million in 2009, an increase of $21.0 million, or 11.2 percent, primarily due to additional assets being placed in service, including OU Spirit that was placed in service in November and December 2009 and Windspeed that was placed in service on March 31, 2010.

Additional Information

Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction was $11.4 million in 2010 as compared to $15.1 million in 2009, a decrease of $3.7 million, or 24.5 percent, primarily due to the completion of OU Spirit in November and December 2009 and Windspeed on March 31, 2010.

Other Income. Other income was $6.5 million in 2010 as compared to $20.4 million in 2009, a decrease of $13.9 million, or 68.1 percent. The decrease in other income was primarily due to:

- a decrease of $10.0 million due to a decreased level of gains recognized in the guaranteed flat bill program in 2010 from higher than expected usage resulting from warmer weather in addition to more customers participating in the guaranteed flat bill program in 2010; and
- a decrease of $2.6 million related to the benefit associated with the tax gross-up of allowance for equity funds used during construction.

Other Expense. Other expense was $1.6 million in 2010 as compared to $6.7 million in 2009, a decrease of $5.1 million or 76.1 percent, primarily due to a decrease in charitable contributions in 2010 as the holding company made the charitable contributions in 2010.

Interest Expense. Interest expense was $103.4 million in 2010 as compared to $93.6 million in 2009, an increase of $9.8 million, or 10.5 percent. The increase in interest expense was primarily due to:

- an $8.2 million increase related to the issuance of $250 million of long-term debt in June 2010; and
- a $2.8 million increase due to a lower allowance for borrowed funds used during construction in 2010 as compared to 2009.

Income Tax Expense. Income tax expense was $111.0 million in 2010 as compared to $90.0 million in 2009, an increase of $21.0 million, or 23.3 percent, primarily due to:

- higher pre-tax income in 2010 as compared to 2009;
- an adjustment for the elimination of the tax deduction for the Medicare Part D subsidy; and
- the write-off of previously recognized Oklahoma investment tax credits primarily due to expenditures no longer eligible for the Oklahoma investment tax credit related to the change in the tax method of accounting for capitalization of repair expenditures.

These increases in income tax expense were partially offset by an increase in Federal renewable energy credits in 2010 as compared to 2009.

Enogex (Natural Gas Midstream Operations)

Year ended December 31, 2011	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	$ **410.5**	$ **1,167.1**	$ **678.0**	$ **(468.5)**	$ **1,787.1**
Cost of goods sold	**253.3**	**870.7**	**688.1**	**(465.5)**	**1,346.6**
Gross margin on revenues	**157.2**	**296.4**	**(10.1)**	**(3.0)**	**440.5**
Other operation and maintenance	**46.5**	**111.8**	**7.3**	**(3.1)**	**162.5**
Depreciation and amortization	**21.6**	**55.6**	**0.4**	**—**	**77.6**
Impairment of assets	**—**	**6.3**	**—**	**—**	**6.3**
Gain on insurance proceeds	**—**	**(3.0)**	**—**	**—**	**(3.0)**
Taxes other than income	**14.7**	**7.0**	**0.3**	**0.1**	**22.1**
Operating income (loss)	$ **74.4**	$ **118.7**	$ **(18.1)**	$ **—**	$ **175.0**

Year ended December 31, 2010	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	$ 403.6	$ 1,005.6	$ 798.5	$ (500.0)	$ 1,707.7
Cost of goods sold	246.4	733.3	804.7	(499.3)	1,285.1
Gross margin on revenues	157.2	272.3	(6.2)	(0.7)	422.6
Other operation and maintenance	48.9	91.5	8.4	(3.5)	145.3
Depreciation and amortization	21.1	50.1	0.1	—	71.3
Impairment of assets	0.7	0.4	—	—	1.1
Taxes other than income	13.9	6.4	0.3	—	20.6
Operating income (loss)	$ 72.6	$ 123.9	$ (15.0)	$ 2.8	$ 184.3

Year ended December 31, 2009	Transportation and Storage	Gathering and Processing	Marketing	Eliminations	Total
(In millions)					
Operating revenues	$ 401.0	$ 657.5	$ 619.9	$ (473.3)	$ 1,205.1
Cost of goods sold	239.9	458.8	617.7	(468.9)	847.5
Gross margin on revenues	161.1	198.7	2.2	(4.4)	357.6
Other operation and maintenance	40.9	87.2	9.2	(4.7)	132.6
Depreciation and amortization	20.4	43.9	0.1	—	64.4
Impairment of assets	0.9	1.9	—	—	2.8
Taxes other than income	13.2	5.5	0.4	—	19.1
Operating income (loss)	$ 85.7	$ 60.2	$ (7.5)	$ 0.3	$ 138.7

Operating Data

Year ended December 31	**2011**	2010	2009
Gathered volumes – TBtu/d	**1.36**	1.32	1.25
Incremental transportation volumes – TBtu/d (A)	**0.58**	0.40	0.54
Total throughput volumes – TBtu/d	**1.94**	1.72	1.79
Natural gas processed – TBtu/d	**0.79**	0.82	0.70
NGLs sold (keep-whole) – million gallons	**167**	187	110
NGLs sold (purchased for resale) – million gallons	**487**	470	351
NGLs sold (percent-of-liquids) – million gallons	**25**	26	27
NGLs sold (percent-of-proceeds) – million gallons	**6**	5	5
Total NGLs sold – million gallons	**685**	688	493
Average NGLs sales price per gallon	**$ 1.16**	$ 0.96	$ 0.77
Average natural gas sales price per MMBtu	**$ 4.08**	$ 4.24	$ 3.37

(A) Incremental transportation volumes consist of natural gas moved only on the transportation pipeline.

2011 compared to 2010. Enogex's operating income decreased $9.3 million, or 5.0 percent, in 2011 as compared to 2010. This decrease was primarily due to higher other operation and maintenance expense, higher depreciation and amortization expense, lower average natural gas prices and a slight decrease in inlet processing volumes related to the 120 MMcf/d Cox City natural gas processing plant being out of service due to the fire from December 2010 until September 2011 and the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in April 2011. These decreases were partially offset by higher NGLs prices and increased gathered volumes associated with ongoing expansion projects. In the normal course of Enogex's business, the operation of its gathering, processing and transportation assets results in the creation of physical natural gas long/short positions. These physical positions can result from gas imbalances, actual versus contractual settlement differences, fuel tracker obligations and natural gas received in-kind for compensation or reimbursements. Enogex actively manages its monthly net position through either selling excess gas or purchasing additional gas needs from third parties through OER. In 2011, volume changes and realized margin on physical gas long/short positions decreased the gross margin by $14.8 million, net of corresponding imbalance and fuel tracker obligations and the impact of the recovery of prior years' under-recovered fuel positions during 2010.

Other operation and maintenance expense increased $17.2 million, or 11.8 percent, primarily due to:

- increased payroll and benefits costs due to increased headcount to support business growth;
- increased contract technical and professional services expense and materials and supplies expense due to an increase in non-capital projects in 2011;
- increased property insurance costs;
- increased rental expense due to growing demand for compression as Enogex's business expands; and
- increased costs due to soil remediation projects.

Depreciation and amortization expense increased $6.3 million, or 8.8 percent, primarily due to additional assets placed in service throughout 2010 and 2011.

Impairment of assets increased $5.2 million in 2011 primarily due to an impairment of $5.0 million related to the leased Atoka processing plant as a result of a management decision in August 2011 to use third-party processing exclusively for gathered volumes dedicated to Atoka and, therefore, to take the processing plant out of service and return it to the lessor in accordance with the rental agreement. The noncontrolling interest portion of the impairment was $2.5 million which is included in Net Income Attributable to Noncontrolling Interests in the Company's Consolidated Statement of Income.

Gain on insurance proceeds was $3.0 million in 2011 with no comparable item in 2010. The gain on insurance proceeds was for reimbursement related to the damaged train at the Cox City natural gas processing plant being replaced and the facility being returned to full service in September 2011.

Transportation and Storage

The transportation and storage business contributed $157.2 million of Enogex's consolidated gross margin in each of 2011 and 2010. The transportation operations contributed $125.9 million of Enogex's consolidated gross margin in 2011 as compared to $124.3 million in 2010. The storage operations contributed $31.3 million of Enogex's consolidated gross margin in 2011 as compared to $32.9 million in 2010. Factors affecting the transportation and storage gross margin were:

- higher capacity lease services under the MEP and Gulf Crossing capacity leases in 2011 as a result of pipeline integrity work on an Enogex pipeline in 2010, which increased the gross margin by $7.1 million;
- higher firm 311 services due to new contracts with more favorable rates in 2011, which increased the gross margin by $5.4 million;
- higher interruptible transportation fees due to new contracts with more favorable rates in 2011, which increased the gross margin by $1.6 million; and
- higher crosshaul revenues in 2011 resulting from the reversal of a previously recognized reserve of $3.0 million associated with the settlement of Enogex's 2009 FERC Section 311 rate case partially offset by decreased utilization of $2.5 million in 2011 due to shippers utilizing crosshaul service in 2010 as a result of pipeline integrity work, which increased the 2011 gross margin by $0.5 million; and
- lower volumes and realized margin on sales of physical natural gas long positions associated with transportation operations in 2011. Gross margin in 2011 included the under recovery of fuel positions as compared to 2010 that included the recovery of prior year's under-recovered fuel positions, which reduced the gross margin in 2011 by $12.1 million, net of imbalance and fuel tracker obligations.

Other operation and maintenance expense for the transportation and storage business was $2.4 million, or 4.9 percent, lower in 2011 as compared to 2010 primarily due to decreased contract technical and professional services expense and materials and supplies expense due to a decrease in non-capital projects in 2011 partially offset by an increase in payroll and benefits costs due to increased headcount to support business growth.

Gathering and Processing

The gathering and processing business contributed $296.4 million of Enogex's consolidated gross margin in 2011 as compared to $272.3 million in 2010, an increase of $24.1 million, or 8.9 percent. The gathering operations contributed $125.2 million of Enogex's consolidated gross margin in 2011 as compared to $117.6 million in 2010. The processing operations contributed $171.2 million of Enogex's consolidated gross margin in 2011 as compared to $154.7 million in 2010.

In 2011, Enogex realized a higher gross margin in its gathering and processing operations primarily as the result of continued growth in gathered volumes from ongoing expansion projects, primarily in the Granite Wash play and Cana/Woodford Shale play, which has added richer natural gas to Enogex's system and higher NGLs prices. Although gathered volumes increased over 2010, gathering and processing volumes grew at a slower pace during the fourth quarter of 2011 than Enogex had anticipated. Enogex currently expects that this slower growth will continue during 2012. The increased gathering volumes were partially offset by the contract conversion of one of Enogex's five largest customer's Oklahoma production volumes to fixed fee effective July 1, 2011, a slight decrease in inlet processing volumes related to the 120 MMcf/d Cox City natural gas processing plant being out of service due to the fire from December 2010 until September 2011, the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in April 2011 and lower average natural gas prices. Overall, the above factors resulted in an increased gross margin on keep-whole processing of $4.8 million and on percent-of-liquids and percent-of-proceeds contracts of $2.6 million.

Other factors that contributed to the increase in the gathering and processing gross margin were:

- an increase in condensate revenues associated with higher condensate prices and volumes, which increased the gross margin by $11.1 million; and
- an increase in gathering fees associated with ongoing expansion projects, which increased the gross margin by $10.7 million.

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

- an increase in the utilization of third-party processing as a result of the reduced capacity related to the Cox City processing plant being out of service until September 2011 and the Atoka processing plant being taken out of service in August 2011, which decreased the gross margin by $3.4 million; and
- lower volumes and realized margin on sales of physical natural gas long positions associated with gathering operations, which decreased the gross margin in 2011 by $2.7 million, net of imbalance and fuel tracker obligations.

Other operation and maintenance expense for the gathering and processing business was $20.3 million, or 22.2 percent, higher in 2011 as compared to 2010 primarily due to:

- increased payroll and benefits costs due to increased headcount to support business growth;
- increased contract technical and professional services expense and materials and supplies expense due to an increase in non-capital projects in 2011;
- increased rental expense due to growing demand for compression as Enogex's business expands; and
- increased costs due to soil remediation projects.

Marketing

The marketing business recognized a loss of $10.1 million as part of Enogex's consolidated gross margin in 2011 as compared to a loss of $6.2 million in 2010, a decrease in the gross margin of $3.9 million, primarily due to:

- lower of cost or market adjustments on the natural gas storage inventory reflective of higher inventory volumes in 2011, which decreased the gross margin by $3.6 million; and
- lower realized margin on sale of natural gas inventory from storage due to a reduction in the realized natural gas market spreads, which decreased the gross margin by $2.8 million.

These decreases are partially offset by more favorable results from OER's customer-focused risk management services, natural gas marketing activities and its trading activities and the expiration of an unfavorable transportation contract, which increased the gross margin by $2.2 million.

Enogex Consolidated Information

Other Income. Enogex's consolidated other income was $3.9 million in 2011 as compared to $0.2 million in 2010, an increase of $3.7 million, primarily due to the recognition of a gain related to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in April 2011.

Interest Expense. Enogex's consolidated interest expense was $22.9 million in 2011 as compared to $30.4 million in 2010, a decrease of $7.5 million, or 24.7 percent, primarily due to:

- an increase of $6.1 million in capitalized interest related to increased construction activity in 2011; and
- a decrease of $1.0 million in interest expense in 2011 due to the retirement of long-term debt in January 2010.

Income Tax Expense. Enogex's consolidated income tax expense was $51.7 million in 2011 as compared to $57.7 million in 2010, a decrease of $6.0 million, or 10.4 percent, primarily due to:

- lower pre-tax income in 2011 as compared to 2010; and
- the one-time, non-cash charge in 2010 for the elimination of the tax deduction for the Medicare Part D subsidy.

Noncontrolling Interest. Enogex's net income attributable to noncontrolling interest was $20.8 million in 2011 as compared to $5.1 million in 2010, an increase of $15.7 million, due to the equity sale of a membership interest in Enogex Holdings to the ArcLight group partially offset by an impairment recorded in August 2011 related to the Atoka processing plant.

Non-Recurring Item. In 2011, Enogex had an increase in net income of $2.3 million relating to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets in April 2011, which Enogex does not consider to be reflective of its ongoing performance.

Timing Item. Enogex's net income in 2011 was $82.2 million, which included a loss of $2.6 million resulting from recording OER's natural gas storage inventory at the lower of cost or market value. The offsetting gains from the sale of withdrawals from inventory are expected to be realized during the first quarter of 2012.

2010 compared to 2009. Enogex's operating income increased $45.6 million, or 32.9 percent, in 2010 as compared to 2009. This increase was primarily due to higher processing spreads, higher NGLs prices, higher natural gas prices, increased volumes and higher gallons per million cubic foot of natural gas associated with expansion projects. Additionally, the fourth quarter 2009 addition of the higher efficiency Clinton processing plant enabled Enogex to optimize recoveries across all processing plants. In the normal course of Enogex's business, the operation of its gathering, processing and transportation assets results in the creation of physical natural gas long/short positions. These physical positions can result from gas imbalances, actual versus contractual settlement differences, fuel tracker obligations and natural gas received in-kind for compensation or reimbursements. Enogex actively manages its monthly net position through either selling excess gas or purchasing additional gas needs from third parties through OER.

Other operation and maintenance expense increased $12.7 million, or 9.6 percent, primarily due to salary increases in 2010, increased costs related to pipeline integrity assessments and other non-capital projects and the 2009 reversal of a reserve related to the dismissal of a previously reported natural gas measurement case partially offset by decreased costs associated with the 2010 settlement of the November 2008 pipeline rupture and the recognition of a related insurance reimbursement.

Depreciation and amortization expense increased $5.2 million, or 7.7 percent, primarily due to additional assets placed in service throughout 2009 and 2010.

Taxes other than income increased $1.5 million, or 7.9 percent, primarily due to an increase in ad valorem tax expense as a result of assets placed in service in 2009.

Transportation and Storage

The transportation and storage business contributed $157.2 million of Enogex's consolidated gross margin in 2010 as compared to $161.1 million in 2009, a decrease of $3.9 million, or 2.4 percent. The transportation operations contributed $124.3 million of Enogex's consolidated gross margin in 2010 as compared to $130.3 million in 2009. The storage operations contributed $32.9 million of Enogex's consolidated gross margin in 2010 as compared to $30.8 million in 2009. The transportation and storage gross margin decreased primarily due to:

- lower revenues resulting from refunds associated with lease services under the MEP and Gulf Crossing capacity leases and the firm 311 services due to pipeline integrity work, which decreased the gross margin by $9.2 million;
- lower crosshaul volumes as fewer customers moved natural gas to eastern markets in 2010 as there were smaller differences in natural gas prices at various U.S. market locations partially offset by customers utilizing crosshaul services due to pipeline integrity work on an Enogex pipeline, which decreased the gross margin by $5.7 million;
- lower realized margins on operational storage hedges as the result of lower transacted volumes in 2010 as compared to 2009, which decreased the gross margin by $2.3 million;
- lower storage fees due to a reduction in the market value of storage capacity, which decreased the gross margin by $2.0 million; and
- decreased interruptible transportation revenues due to gathering customers shipping production through the firm capacity leases and firm 311 East side service, which decreased the gross margin by $1.6 million.

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

- lease services under the MEP and Gulf Crossing capacity leases and firm 311 services due to these services being available beginning in the second quarter 2009, which increased the gross margin by $9.0 million;
- no adjustment of natural gas storage inventory in 2010 as compared to $5.8 million lower of cost or market adjustment to the natural gas storage inventory in 2009 due to lower natural gas prices;
- a decrease in the imbalance liability, net of fuel recoveries and natural gas length positions, which increased the gross margin by $1.2 million; and
- higher transportation demand fees due to new contracts which began in 2010, which increased the gross margin by $1.1 million.

Other operation and maintenance expense for the transportation and storage business was $8.0 million, or 19.6 percent, higher in 2010 as compared to 2009 primarily due to salary increases in 2010, increased costs of $3.9 million related to pipeline integrity assessments and other non-capital projects and the 2009 reversal of a $1.5 million reserve related to the dismissal of a previously reported natural gas measurement case.

Gathering and Processing

The gathering and processing business contributed $272.3 million of Enogex's consolidated gross margin in 2010 as compared to $198.7 million in 2009, an increase of $73.6 million, or 37.0 percent. The gathering operations contributed $117.6 million of Enogex's consolidated gross margin in 2010 as compared to $114.0 million in 2009. The processing operations contributed $154.7 million of Enogex's consolidated gross margin in 2010 as compared to $84.7 million in 2009.

In 2010, Enogex realized a higher gross margin in its gathering and processing operations primarily as the result of continued growth in gathered volumes, higher processing spreads, higher NGLs prices and higher natural gas prices, net of Enogex's continued effort to convert customers from keep-whole to fixed-fee processing arrangements. Enogex's processing plants saw a 17.0 percent increase in inlet volumes, an increase in NGLs production as recent expansion projects, primarily in the Granite Wash play and Cana/Woodford Shale play have added richer natural gas to Enogex's system and the fourth quarter 2009 completion of the new higher efficiency Clinton processing plant allowed Enogex to optimize recoveries across all processing plants. In December 2010, a fire occurred at Enogex's Cox City natural gas processing plant, and gas volumes normally processed at the Cox City plant were diverted to other facilities by the end of December. Overall, the above factors resulted in the following:

- increased gross margin on keep-whole processing of $35.8 million;
- increased fixed processing fees of $13.8 million; and
- increased gross margin on NGLs retained under percent-of-liquids contracts of $11.4 million.

Other factors that contributed to the increase in the gathering and processing gross margin were:

- an increase in condensate revenues associated with the gathering and processing operations as a result of increased volumes associated with new expansion projects with a higher gallons per million cubic foot of natural gas and higher condensate prices, which increased the gross margin by $11.6 million; and
- increased gathered volumes associated with expansion projects, which increased the gross margin by $4.3 million.

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

- lower volumes and realized margin on sales of physical natural gas long/short positions associated with gathering operations, which decreased the gross margin by $1.3 million, net of imbalance and fuel tracker obligations; and
- increased processing fees associated with the increased utilization of a third-party processing plant for processing natural gas associated with Atoka, which decreased the gross margin by $1.2 million.

Other operation and maintenance expense for the gathering and processing business was $4.3 million, or 4.9 percent, higher in 2010 as compared to 2009 primarily due to an increase of $2.1 million in non-capital project costs partially offset by decreased costs associated with the 2010 settlement of the November 2008 pipeline rupture and the recognition of a related insurance reimbursement.

Marketing

The marketing business recognized a loss of $6.2 million as part of Enogex's consolidated gross margin in 2010 as compared to a gain of $2.2 million in 2009, a decrease of $8.4 million. The marketing gross margin decreased primarily due to:

- smaller differences in natural gas prices at various U.S. market locations which resulted in a reduced spread that OER was able to realize from delivering gas under its transportation contracts, which decreased the gross margin by $5.5 million;
- timing of the withdrawal and sale of natural gas inventory from OER's storage contracts, which decreased the gross margin by $1.9 million; and
- selective deal execution to limit credit and commodity price risks in the current market environment, as well as lack of spreads and volatility in the natural gas commodity markets, resulted in limited opportunities for OER in its customer-focused risk management services and natural gas marketing activities, which decreased the gross margin by $1.0 million.

Enogex Consolidated Information

Interest Expense. Enogex's consolidated interest expense was $30.4 million in 2010 as compared to $36.5 million in 2009, a decrease of $6.1 million, or 16.7 percent, primarily due to:

- a decrease of $7.0 million in interest expense in 2010 as compared to 2009 due to a lower interest rate on long-term debt issued in 2009 as compared to the interest rate on long-term debt that was retired in January 2010; and
- a $2.8 million tender payment on the tender offer Enogex completed in July 2009 related to the retirement of $110.8 million of senior notes.

These decreases in interest expense were partially offset by a decrease of $3.8 million in capitalized interest related to lower capital expenditures and fewer projects qualifying for capitalized interest in 2010 as compared to 2009.

Income Tax Expense. Enogex's consolidated income tax expense was $57.7 million in 2010 as compared to $37.8 million in 2009, an increase of $19.9 million, or 52.6 percent, primarily due to higher pre-tax income in 2010 as compared to 2009 and an adjustment for the elimination of the tax deduction for the Medicare Part D subsidy.

Noncontrolling Interest. Enogex's net income attributable to noncontrolling interest was $5.1 million in 2010 as compared to $2.8 million in 2009, an increase of $2.3 million, or 82.1 percent, due to the equity investment by the ArcLight group in November 2010 in exchange for a 9.9 percent membership interest in Enogex Holdings.

Non-recurring Items. Enogex had net income of $91.1 million in 2010, which did not include any items that Enogex does not consider to be reflective of its ongoing operations. Enogex had net income of $61.3 million in 2009, which includes a net loss of $0.8 million for items Enogex did not consider to be reflective of its ongoing operations. This decrease in Enogex's consolidated net income included a tender payment on the tender offer Enogex completed in July 2009 of $1.7 million after-tax for the purchase of $110.8 million of Enogex's $400 million 8.125% senior notes that matured on January 15, 2010, which was partially offset by the reversal of a reserve of $0.9 million after-tax in 2009 related to the dismissal of a previously reported natural gas measurement case.

Financial Condition

The balance of Accounts Receivable, Net was $322.5 million and $277.9 million at December 31, 2011 and 2010, respectively, an increase of $44.6 million, or 16.0 percent, primarily due to an increase in billings to OG&E's customers in 2011 while customers received a refund in 2010 for the over collection of fuel.

The balance of Fuel Inventories was $100.7 million and $158.8 million at December 31, 2011 and 2010, respectively, a decrease of $58.1 million, or 36.6 percent, primarily due to lower coal inventory balances at OG&E from higher coal generation.

The balance of Property, Plant and Equipment in Service was $10,315.9 million and $9,188.0 million at December 31, 2011 and 2010, respectively, an increase of $1,127.9 million, or 12.3 percent, primarily due to assets placed in service in 2011, including the Crossroads wind farm, distribution and transmission projects and Smart Grid assets at OG&E as well as gathering and processing projects at Enogex.

The balance of Intangible Assets, Net was $137.0 million and $2.8 million at December 31, 2011 and 2010, respectively, an increase of $134.2 million, primarily due to certain gas gathering acquisitions as discussed in Note 3 of Notes to Consolidated Financial Statements.

The balance of Goodwill was $39.4 million at December 31, 2011 with no balance at December 31, 2010 due to certain gas gathering acquisitions as discussed in Note 3 of Notes to Consolidated Financial Statements.

The balance of Short-Term Debt was $277.1 million and $145.0 million at December 31, 2011 and 2010, respectively, an increase of $132.1 million, or 91.1 percent, primarily due to an increase in commercial paper borrowings in 2011 for dividend and bond interest payments, capital expenditures for various transmission projects and Crossroads at OG&E and gathering and processing expansion projects at Enogex and daily operational needs partially offset by proceeds received from contributions from the ArcLight group in 2011 and the equity sale of a 0.1 percent membership interest in Enogex Holdings to the ArcLight group in February 2011, a portion of which were used to repay outstanding commercial paper borrowings.

The balance of Accounts Payable was $388.0 million and $321.7 million at December 31, 2011 and 2010, respectively, an increase of $66.3 million, or 20.6 percent, primarily due to the timing of outstanding checks clearing the bank and an increase in accruals related to Crossroads and Smart Grid projects at OG&E and expansion projects at Enogex.

The balance of Current Price Risk Management Liabilities was $0.4 million and $16.8 million at December 31, 2011 and 2010, respectively, a decrease of $16.4 million or 97.6 percent, primarily due to Enogex hedges of keep-whole processing agreements that matured during 2011.

The balance of Fuel Clause Over Recoveries was $7.7 million and $29.9 million at December 31, 2011 and 2010, respectively, a decrease of $22.2 million, or 74.2 percent, primarily due to the fact that the amount billed to retail customers was lower than OG&E's cost of fuel. OG&E's fuel recovery clauses are designed to smooth the impact of fuel price volatility on customers' bills. As a result, OG&E under recovers fuel costs in periods of rising fuel prices above the baseline charge for fuel and over recovers fuel 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.

The balance of Long-Term Debt was $2,737.1 million and $2,362.9 million at December 31, 2011 and 2010, respectively, an increase of $374.2 million, or 15.8 percent, due to the issuance of $250 million of long-term debt in May 2011 and an increase in borrowings under Enogex LLC's revolving credit agreement.

The balance of Accrued Benefit Obligations was $360.8 million and $372.4 million at December 31, 2011 and 2010, respectively, a decrease of $11.6 million, or 3.1 percent, primarily due to amendments to the Company's retiree medical plan adopted in January 2011 (see Note 14 of Notes to Consolidated Financial Statements) and Pension Plan contributions in 2011 partially offset by net losses for the Company's Pension Plan, restoration of retirement income plan and postretirement benefit plans.

The balance of Deferred Income Taxes was $1,651.4 million and $1,434.8 million at December 31, 2011 and 2010, respectively, an increase of $216.6 million, or 15.1 percent, primarily due to accelerated bonus tax depreciation partially offset by the Company being in a tax net operating loss position in 2011.

The balance of Regulatory Liabilities was $230.7 million and $193.1 million at December 31, 2011 and 2010, respectively, an increase of $37.6 million, or 19.5 percent, primarily due to increases related to removal obligations for OG&E distribution, transmission and generation assets and Oklahoma pension regulatory liabilities.

The balance of Other Deferred Liabilities was $61.2 million and $45.3 million at December 31, 2011 and 2010, respectively, an increase of $15.9 million, or 35.1 percent, primarily due to an asset retirement obligation related to the Crossroads wind farm.

The balance of Accumulated Other Comprehensive Loss was $40.6 million and $60.2 million at December 31, 2011 and 2010, respectively, a decrease of $19.6 million, or 32.6 percent, primarily due to amendments to the Company's retiree medical plan adopted in January 2011 (see Note 14 of Notes to Consolidated Financial Statements) and NGLs hedges maturing in 2011 partially offset by net losses for the Pension Plan, restoration of retirement income plan and postretirement benefit plans.

The balance of Noncontrolling Interests was $256.0 million and $110.4 million at December 31, 2011 and 2010, respectively, an increase of $145.6 million, primarily due to contributions from the ArcLight group in 2011 and the equity sale of a 0.1 percent membership interest in Enogex Holdings to the ArcLight group in February 2011 partially offset by distributions to the ArcLight group in 2011.

Off-Balance Sheet Arrangement

OG&E Railcar Lease Agreement

OG&E has a noncancellable operating lease with purchase options, covering 1,392 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 15, 2010, OG&E renewed the lease agreement effective February 1, 2011. At the end of the new lease term, which is February 1, 2016, 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 fair 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 $22.8 million.

OG&E is also required to maintain all of the railcars it has under lease to transport coal from Wyoming and has entered into agreements with Progress Rail Services and WATCO, both of which are non-affiliated companies, to furnish this maintenance.

Liquidity and Capital Resources

Cash Flows

Year ended December 31 *(In millions)*	**2011**	2010	2009
Net cash provided from operating activities	**$ 833.9**	$ 782.5	$ 654.5
Net cash used in investing activities	**(1,395.8)**	(846.1)	(808.5)
Net cash provided from financing activities	**564.2**	7.8	37.7

Operating Activities

The increase of $51.4 million, or 6.6 percent, in net cash provided from operating activities in 2011 as compared to 2010 was primarily due to lower fuel refunds at OG&E in 2011 as compared to 2010 and cash received in 2011 from an increase in billings to OG&E's customers due to warmer weather in OG&E's service territory in 2011 partially offset by income tax refunds received in 2010 related to a carry back of the 2008 tax loss resulting from a change in tax method of accounting for capitalization of repair expenditures and accelerated tax bonus depreciation.

The increase of $128.0 million, or 19.6 percent, in net cash provided from operating activities in 2010 as compared to 2009 was primarily due to:

- an increase in cash receipts for sales at Enogex due to an increase in natural gas prices and NGLs prices and volumes in 2010 as compared to 2009;
- income tax refunds received in 2010 related to a carry back of the 2008 tax loss resulting from a change in tax method of accounting for capitalization of repair expenditures and accelerated tax bonus depreciation;
- a cash collateral payment to counterparties of OER related to OER's NGLs hedge positions in 2009; and
- cash received in 2010 from the implementation of rate increases and riders at OG&E.

These increases in net cash provided from operating activities were partially offset by:

- an increase in payments for purchases at Enogex due to an increase in natural gas prices and NGLs prices and volumes in 2010 as compared to 2009; and
- higher fuel refunds at OG&E in 2010 as compared to 2009.

Investing Activities

The increase of $549.7 million, or 65.0 percent, in net cash used in investing activities in 2011 as compared to 2010 primarily related to higher levels of capital expenditures in 2011 related to various transmission projects and Crossroads at OG&E and gathering and processing expansion projects at Enogex.

The increase of $37.6 million, or 4.7 percent, in net cash used in investing activities in 2010 as compared to 2009 primarily related to a customer's reimbursement of Enogex's costs related to the ongoing construction of a transportation pipeline in 2009.

Financing Activities

The increase of $556.4 million in net cash provided from financing activities in 2011 as compared to 2010 was primarily due to:

- repayment in 2010 of the remaining balance of Enogex LLC's $400 million 8.125% senior notes which matured on January 15, 2010;
- an increase in short-term debt borrowings in 2011 as compared to 2010;
- contributions from the noncontrolling interest partners in 2011;
- higher borrowings under Enogex LLC's revolving credit agreement in 2011; and
- a decrease in repayments of borrowings under Enogex LLC's revolving credit agreement in 2011 as compared to 2010.

The decrease of $29.9 million, or 79.3 percent, in net cash provided from financing activities in 2010 as compared to 2009 was primarily due to:

- repayment of the remaining balance of Enogex LLC's $400 million 8.125% senior notes which matured on January 15, 2010 partially offset by the retirement of $110.8 million of senior notes related to the tender offer Enogex completed in July 2009;
- proceeds received from the issuance of $450 million of long-term debt at Enogex LLC in June 2009; and
- a decrease in the issuance of common stock in 2010.

These decreases in net cash provided from financing activities were partially offset by:

- proceeds received from the issuance of $250 million of long-term debt at OG&E in June 2010;
- proceeds received from the ArcLight group for the equity investment in Enogex Holdings in November 2010;
- lower repayments of short-term debt borrowings in 2010;
- a higher level of proceeds received from borrowings on Enogex LLC's line of credit in 2010; and
- a higher level of repayments made on Enogex LLC's line of credit in 2009.

Future Capital Requirements and Financing Activities

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, 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.

Capital Expenditures

The Company's consolidated estimates of capital expenditures for the years 2012 through 2016 are shown in the following table. These capital expenditures represent the base maintenance capital expenditures (i.e., capital expenditures to maintain and operate the Company's businesses) plus capital expenditures for known and committed projects.

(In millions)	2012	2013	2014	2015	2016
OG&E Base Transmission	$ 80	$ 50	$ 50	$ 50	$ 50
OG&E Base Distribution	195	200	200	200	200
OG&E Base Generation	110	80	80	80	80
OG&E Other	30	30	30	30	30
Total OG&E Base Transmission, Distribution, Generation and Other	415	360	360	360	360
OG&E Known and Committed Projects:					
Transmission Projects:					
Sunnyside-Hugo (345 kilovolt)	25	—	—	—	—
Sooner-Rose Hill (345 kilovolt)	5	—	—	—	—
Balanced Portfolio 3E Projects	110	180	50	—	—
SPP Priority Projects	20	200	115	—	—
Total Transmission Projects	160	380	165	—	—
Other Projects:					
Smart Grid Program (A)	90	35	40	20	20
Crossroads	40	—	—	—	—
System Hardening	15	—	—	—	—
Total Other Projects	145	35	40	20	20
Total OG&E Known and Committed Projects	305	415	205	20	20
Total OG&E (B)	720	775	565	380	380
Enogex LLC Base Maintenance	60	50	55	60	65
Enogex LLC Known and Committed Projects:					
Western Oklahoma / Texas Panhandle Gathering Expansion	215	115	15	5	5
Other Gathering Expansion	25	25	20	20	20
Total Enogex LLC Known and Committed Projects	240	140	35	25	25
Total Enogex LLC (C)	300	190	90	85	90
OGE Energy	20	20	20	20	20
Total capital expenditures	$ 1,040	$ 985	$ 675	$ 485	$ 490

(A) These capital expenditures are net of the $130 million Smart Grid grant approved by the U.S. Department of Energy.

(B) The capital expenditures above exclude any environmental expenditures associated with pollution control equipment related to regional haze requirements due to the uncertainty regarding the timing and costs for such pollution control equipment. OG&E has committed to install low NOX burners at the affected generating units at a cost preliminarily estimated between $70 million and $130 million, but the timing of the installation of such burners is uncertain. The SO2 emissions standards in the EPA's Federal implementation plan could require the installation of Dry Scrubbers or fuel switching. OG&E estimates that installing such Dry Scrubbers could cost more than $1.0 billion. The Federal implementation plan is being challenged by OG&E and the state of Oklahoma. Neither the outcome of the challenge to the Federal implementation plan nor the timing and amount of any required capital expenditures can be predicted with any certainty at this time, but such capital expenditures could be significant. For further information, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Environmental Laws and Regulations" below.

(C) These capital expenditures represent 100 percent of Enogex LLC's capital expenditures, of which a portion may be funded by the ArcLight group. Until the ArcLight group owns 50 percent of the equity of Enogex Holdings, the ArcLight group will fund capital contributions in an amount higher than its proportionate interest. If necessary, the ArcLight group will fund between 50 percent and 90 percent of required capital contributions during that period. The remainder of the required capital contributions (i.e., between 10 percent and 50 percent) will be funded by OGE Holdings.

Additional capital expenditures beyond those identified in the table above, including additional incremental growth opportunities in electric transmission assets and at Enogex LLC, will be evaluated based upon their impact upon achieving the Company's financial objectives. The capital expenditure projections related to Enogex LLC in the table above reflect base market conditions at February 16, 2012 and do not reflect the potential opportunity for a set of growth projects that could materialize. Also, if drilling activity declines in the future, this could reduce Enogex's capital expenditures in the table above.

Contractual Obligations

The following table summarizes the Company's contractual obligations at December 31, 2011. See the Company's Consolidated Statements of Capitalization and Note 16 of Notes to Consolidated Financial Statements for additional information.

(In millions)	2012	2013-2014	2015-2016	After 2016	Total
Maturities of long-term debt (A)	$ —	$ 300.0	$ 260.0	$ 2,185.4	$ 2,745.4
Operating lease obligations					
OG&E railcars	2.9	5.7	30.1	—	38.7
Enogex noncancellable operating leases	3.9	5.4	4.6	0.6	14.5
Total operating lease obligations	6.8	11.1	34.7	0.6	53.2
Other purchase obligations and commitments					
OG&E cogeneration capacity and fixed operation and maintenance payments	90.3	176.7	168.5	401.1	836.6
OG&E expected cogeneration energy payments	59.3	150.2	161.0	600.8	971.3
OG&E minimum fuel purchase commitments	380.2	280.3	90.4	—	750.9
OG&E expected wind purchase commitments	32.4	66.1	68.7	492.0	659.2
OG&E long-term service agreement commitments	4.5	40.3	10.1	59.8	114.7
OER Cheyenne Plains commitments	5.3	13.0	1.6	—	19.9
OER MEP commitments	2.1	3.3	—	—	5.4
OER other commitments	4.9	6.2	3.8	—	14.9
Total other purchase obligations and commitments	579.0	736.1	504.1	1,553.7	3,372.9
Total contractual obligations	585.8	1,047.2	798.8	3,739.7	6,171.5
Amounts recoverable through fuel adjustment clause (B)	(474.8)	(502.3)	(350.2)	(1,092.8)	(2,420.1)
Total contractual obligations, net	$ 111.0	$ 544.9	$ 448.6	$ 2,646.9	$ 3,751.4

(A) Maturities of the Company's long-term debt during the next five years consist of $300 million and $260 million in years 2014 and 2016, respectively. There are no maturities of the Company's long-term debt in years 2012, 2013 or 2015.

(B) Includes expected recoveries of costs incurred for OG&E's railcar operating lease obligations, OG&E's cogeneration expected energy payments, OG&E's minimum fuel purchase commitments and OG&E's expected wind purchase commitments.

OG&E also has 720 MWs of 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.

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 minimum fuel purchase commitments 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.

Pension and Postretirement Benefit Plans

At December 31, 2011, 38.6 percent of the Pension Plan investments were in listed common stocks with the balance primarily invested in bonds, debentures and notes, U.S. Government securities, a commingled fund and a common collective trust as presented in Note 14 of Notes to Consolidated Financial Statements. In 2011, asset returns on the Pension Plan were 1.4 percent due to the gains in fixed income investments partially offset by losses in equity investments in 2011. During the same time, corporate bond yields, which are used in determining the discount rate for future pension obligations, have continued to decline. During each of 2011 and 2010, OGE Energy made contributions to its Pension Plan of $50 million to help ensure that the Pension Plan maintains an adequate funded status. The level of funding is dependent on returns on plan assets and future discount rates. During 2012, OGE Energy may contribute up to $35 million to its Pension Plan. OGE Energy could be required to make additional contributions if the value of its pension trust and postretirement benefit plan trust assets are adversely impacted by a major market disruption in the future.

The following table presents the status of the Company's Pension Plan, the Restoration of Retirement Income Plan and the postretirement benefit plans at December 31, 2011 and 2010. 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 of Notes to Consolidated Financial Statements) in the Company's Consolidated Balance Sheet. The amounts in Accumulated Other Comprehensive Loss and those recorded as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

	Pension Plan		Restoration of Retirement Income Plan		Postretirement Benefit Plans	
December 31 *(In millions)*	**2011**	2010	**2011**	2010	**2011**	2010
Benefit obligations	**$ (697.7)**	$ (640.9)	**$ (13.3)**	$ (10.8)	**$ (280.6)**	$ (337.1)
Fair value of plan assets	**589.8**	574.0	**—**	—	**61.0**	58.5
Funded status at end of year	**$ (107.9)**	$ (66.9)	**$ (13.3)**	$ (10.8)	**$ (219.6)**	$ (278.6)

Common Stock Dividends

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 Company's financial objective includes increasing the dividend to meet the Company's dividend payout objectives. The Company's target payout ratio is to pay out dividends no more than 60 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 the Company's shareholder base, the Company's financial position, the Company's growth targets, the composition of the Company's assets and investment opportunities. At the Company's December 2011 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 $0.3925 per share from $0.3750 per share effective with the Company's first quarter 2012 dividend.

Security Ratings

	Moody’s Investors Services	Standard & Poor's Ratings Services	Fitch Ratings
OG&E Senior Notes	A2	BBB+	A+
Enogex LLC Notes	Baa3	BBB-	BBB
OGE Energy Senior Notes	Baa1	BBB	A
OGE Energy Commercial Paper	P2	A2	F1

Access to reasonably priced capital is dependent in part on credit and security ratings. Generally, lower ratings lead to higher financing costs. Pricing grids associated with the Company's credit facilities could cause annual fees and borrowing rates to increase if an adverse ratings impact occurs. The impact of any future downgrade could include an increase in the costs of the Company's short-term borrowings, but a reduction in the Company's credit ratings would not result in any defaults or accelerations. Any future downgrade of the Company could 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. In the event Moody's Investors Services or Standard & Poor's Ratings Services were to lower the Company's senior unsecured debt rating to a below investment grade rating, at December 31, 2011, the Company would have been required to post $2.1 million of cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position at December 31, 2011. 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.

On October 25, 2011, Standard & Poor's Ratings Services reaffirmed the security ratings of OGE Energy and OG&E as shown in the table above and downgraded Enogex LLC's security rating from BBB+ to BBB- with a stable outlook. Standard & Poor's Ratings Services indicated that the downgrade at Enogex LLC was primarily due to OGE Energy's lower ownership percentage in Enogex which according to Standard & Poor's Ratings Services, over time, lessens the benefit that Enogex receives from OGE Energy's higher credit rating. The downgrade did not trigger any collateral requirements and will not cause a material increase in fees under the revolving credit agreement.

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.

2011 Capital Requirements, Sources of Financing, Funding of Benefit Plans and Financing Activities

Total capital requirements, consisting of capital expenditures and maturities of long-term debt, were $1,446.2 million and contractual obligations, net of recoveries through fuel adjustment clauses, were $110.2 million resulting in total net capital requirements and contractual obligations of $1,556.4 million in 2011, of which $6.9 million was to comply with environmental regulations. This compares to net capital requirements of $1,111.3 million and net contractual obligations of $104.4 million totaling $1,215.7 million in 2010, of which $27.8 million was to comply with environmental regulations.

In 2011, the Company's sources of capital were cash generated from operations, proceeds from the issuance of long and short-term debt, proceeds from the sales of common stock to the public through the Company's Automatic Dividend Reinvestment and Stock Purchase Plan, funding for growth opportunities at Enogex through the ArcLight group and quarterly distributions from Enogex Holdings. 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.

Funding of Benefit Plans

In November 2011, the Company purchased 120,000 shares of its common stock at an average cost of $51.33 per share on the open market. These shares will be used to satisfy Enogex's portion of the Company's obligation to deliver shares of common stock related to long-term incentive payouts of earned performance units in 2012. The Company expects to purchase shares in the future to satisfy a portion of its obligation under its incentive plan.

OG&E Issuance of Long-Term Debt

On May 24, 2011, OG&E issued $250 million of 5.25% senior notes due May 15, 2041. The proceeds from the issuance were added to OGE Energy's general funds and were used to repay short-term debt. OG&E expects to issue additional long-term debt from time to time when market conditions are favorable and when the need arises.

Potential Collateral Requirements

Derivative instruments are utilized in managing the Company's commodity price exposures and in OER's asset management, marketing and trading activities and hedging activities executed on behalf of the Company. Agreements governing the derivative instruments may require the Company to provide collateral in the form of cash or a letter of credit in the event mark-to-market exposures exceed contractual thresholds or the Company's credit ratings are lowered. Future collateral requirements are uncertain, and are subject to terms of the specific agreements and to fluctuations in natural gas and NGLs market prices.

On July 21, 2010, President Obama signed into law the Dodd-Frank Act. While the Dodd-Frank Act is focused primarily on the regulation and oversight of financial institutions, it also provides for a new regulatory regime for derivatives, including mandatory clearing of certain swaps, exchange trading, margin requirements and other transparency requirements. The Dodd-Frank Act contains provisions that should exempt certain derivatives end-users from much of the clearing requirements. It is unclear whether end-users will be exempt from the margin requirements. The scope of the margin requirements and the end user exemption is uncertain and will be further defined through rulemaking proceedings at the Commodity Futures Trading Commission and the Securities and Exchange Commission. Further, although the Company may qualify for certain exemptions, its derivative counterparties may be subject to new capital, margin and business conduct requirements imposed as a result of the new legislation, which may increase the Company's transaction costs or make it more difficult to enter into hedging transactions on favorable terms. The Company's inability to enter into hedging transactions on favorable terms, or at all, could increase operating expenses and put the Company at increased exposure to risks of adverse changes in commodities prices. If, as a result of the rulemaking associated with the Dodd-Frank Act, the Company does not qualify for any exemptions related to clearing requirements and/or are subject to margin requirements, the Company would be subject to higher costs and increased collateral requirements. The impact of the provisions of the Dodd-Frank Act on the Company cannot be determined pending issuance of the final implementing regulations.

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 and to fund future growth opportunities. Additionally, the Company will have an additional source of funding for growth opportunities at Enogex through the ArcLight group and from quarterly distributions from Enogex Holdings. 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 and Credit Facilities

Short-term borrowings generally are used to meet working capital requirements. The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. In December 2011, the Company, OG&E and Enogex LLC each entered into new unsecured five-year revolving credit facilities totaling in the aggregate $1,550 million ($750 million for the Company, $400 million for OG&E and $400 million for Enogex LLC). The short-term debt balance was $277.1 million and $145.0 million at December 31, 2011 and 2010, respectively. The weighted-average interest rate on short-term debt at December 31, 2011 was 0.48 percent. The average balance of short-term debt in 2011 was $210.7 million at a weighted-average interest rate of 0.36 percent. The maximum month-end balance of short-term debt in 2011 was $323.0 million. Enogex had $150.0 million and $25.0 million in outstanding borrowings under its revolving credit agreement at December 31, 2011 and 2010, respectively. As Enogex LLC's credit agreement matures on December 13, 2016, along with its intent in utilizing its credit agreement, borrowings thereunder are classified as long-term debt in the Company's Consolidated Balance Sheets. At December 31, 2011, the Company had $1,120.7 million of net available liquidity under its revolving credit agreements. 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, 2011 and ending December 31, 2012. At December 31, 2011, the Company had $4.6 million in cash and cash equivalents. See Note 13 of Notes to Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

Expected Issuance of Long-Term Debt

OG&E expects to issue approximately $250 million of long-term debt in late 2012, depending on market conditions, to fund capital expenditures, repay short-term borrowings and for general corporate purposes.

Common Stock

The Company expects to issue between $13 million and $15 million of common stock in its Automatic Dividend Reinvestment and Stock Purchase Plan in 2012. See Note 11 of Notes to Consolidated Financial Statements for a discussion of the Company's common stock activity.

Minimum Quarterly Distributions by Enogex Holdings

Pursuant to the Enogex Holdings LLC Agreement, Enogex Holdings will make minimum quarterly distributions equal to the amount of cash required to cover OGE Energy's anticipated tax liabilities plus $12.5 million, to be distributed in proportion to each member's percentage ownership interest.

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 for all Company segments includes the valuation of Pension Plan assumptions, impairment estimates of long-lived assets (including intangible assets) and goodwill, income taxes, contingency reserves, asset retirement obligations, fair value and cash flow hedges and the allowance for uncollectible accounts receivable. For the electric utility segment, the most significant judgment is also exercised in the valuation of regulatory assets and liabilities and unbilled revenues. For the natural gas transportation and storage, gathering and processing and marketing segments, the most significant judgment is also exercised in the valuation of operating revenues, natural gas purchases, purchase and sale contracts, assets and depreciable lives of property, plant and equipment and amortization methodologies related to intangible assets. The selection, application and disclosure of the following critical accounting estimates have been discussed with the Company's Audit Committee. The Company discusses its significant accounting policies, including those that do not require management to make difficult, subjective, or complex judgments or estimates, in Note 1 of Notes to Consolidated Financial Statements.

Consolidated (including all Company segments)

Pension and Postretirement Benefit Plans

The Company has a Pension Plan that covers substantially all of the Company's employees hired before December 1, 2009. Also, effective December 1, 2009, the Company's Pension Plan is no longer being offered to employees hired on or after December 1, 2009. The Company also has defined benefit postretirement plans that cover substantially all of its employees. Pension and other postretirement plan expenses and liabilities are determined on an actuarial basis and are affected by the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and the level of funding. Actual changes in the fair market value of plan assets and differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension expense ultimately recognized. The pension plan rate assumptions are shown in Note 14 of Notes to Consolidated Financial Statements. The assumed return on plan assets is based on management's expectation of the long-term return on the plan assets portfolio. The discount rate used to compute the present value of plan liabilities is based generally on rates of high-grade corporate bonds with maturities similar to the average period over which benefits will be paid. The level of funding is dependent on returns on plan assets and future discount rates. Higher returns on plan assets and an increase in discount rates will reduce funding requirements to the Pension Plan. The following table indicates the sensitivity of the Pension Plan funded status to these variables.

	Change	Impact on Funded Status
Actual plan asset returns	+/- 5 percent	+/- $29.5 million
Discount rate	+/- 0.25 percent	+/- $20.3 million
Contributions	+/- $10 million	+/- $10 million

Impairment of Long-Lived Assets (Including Intangible Assets) and Goodwill

The Company assesses its long-lived assets, including intangible assets with finite useful lives, for impairment when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset's carrying amount. Estimates of future cash flows used to test the recoverability of long-lived assets and intangible assets 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. 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. In 2011, the Company recorded a pre-tax impairment loss of $5.0 million, of which $2.5 million was the noncontrolling interest portion (see Note 5), related to the Atoka processing plant. The Company recorded no other material impairments in 2011, 2010 and 2009.

As a result of the gas gathering acquisitions on November 1, 2011 discussed in Note 3, Enogex recorded goodwill of $39.4 million and intangible assets of $136.3 million. Enogex will assess its goodwill for impairment at least annually as of October 1 and will assess the intangible assets for impairment as discussed above.

Income Taxes

The Company uses the asset and liability method of accounting for income taxes. Under this method, a deferred tax asset or liability is recognized for the estimated future tax effects attributable to temporary differences between the financial statement basis and the tax basis of assets and liabilities as well as tax credit carry forwards and net operating loss carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period of the change.

The application of income tax law is complex. Laws and regulations in this area are voluminous and often ambiguous. Interpretations and guidance surrounding income tax laws and regulations change over time. Accordingly, it is necessary to make judgments regarding income tax exposure. As a result, changes in these judgments can materially affect amounts the Company recognized in its consolidated financial statements. Tax positions taken by the Company on its income tax returns that are recognized in the financial statements must satisfy a more likely than not recognition threshold, assuming that the position will be examined by taxing authorities with full knowledge of all relevant information.

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 GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements.

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 16 and 17 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.

Asset Retirement Obligations

The Company has previously recorded asset retirement obligations that are being amortized over their respective lives ranging from 20 to 99 years. In the fourth quarter of 2011, OG&E recorded an asset retirement obligation for $13.0 million related to its Crossroads wind farm. Beginning December 1, 2011, OG&E began to amortize the value of the related asset retirement obligation asset over the estimated remaining life of 50 years. The Company also has certain asset retirement obligations 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

The Company designates as cash flow hedges derivatives used to manage commodity price risk exposure for Enogex's NGLs volumes and corresponding keep-whole natural gas resulting from its natural gas processing contracts (processing hedges) and natural gas positions resulting from its natural gas gathering and processing, pipeline and storage operations (operational gas hedges). The Company also designates as cash flow hedges certain derivatives used to manage natural gas commodity exposure for certain natural gas storage inventory positions. 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. Enogex's cash flow hedges at December 31, 2011 mature by the end of the first quarter of 2012.

From time to time, OG&E and Enogex may engage in cash flow and fair value hedge transactions to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Electric Utility Segment

Regulatory Assets and Liabilities

OG&E, as a regulated utility, is subject to accounting principles for certain types of rate-regulated activities, which provide 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 benefit obligations regulatory asset is comprised of expenses recorded which are probable of future recovery and that have not yet been recognized as components of net periodic benefit cost, including net loss, prior service cost and net transition obligation.

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, 2011, 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 $0.3 million. At December 31, 2011 and 2010, Accrued Unbilled Revenues were $59.3 million and $56.8 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 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. Beginning in August 2009 and going forward, there was a change in the provision calculation as a result of the Oklahoma rate case whereby the portion of the uncollectible provision related to fuel is being recovered through the fuel adjustment clause. Due to the extremely hot weather in OG&E's service territory in 2011, OG&E recorded an additional amount of uncollectible expense anticipating higher customer defaults. At December 31, 2011, if the provision rate were to increase or decrease by 10 percent, this would cause a change in the uncollectible expense recognized of $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 $3.7 million and $1.6 million at December 31, 2011 and 2010, respectively.

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

Operating Revenues

Operating revenues for gathering, processing, transportation, storage and marketing 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.

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

Enogex records deferred revenue when it receives consideration from a third party before achieving certain criteria that must be met for revenue to be recognized in accordance with GAAP. In August 2010, Enogex completed construction of transportation and compression facilities necessary to provide gas delivery service to a new natural gas-fired electric generation facility near Pryor, Oklahoma. Aid in Construction payments of $36.4 million received in excess of construction costs were recognized as Deferred Revenues on the Company's Consolidated Balance Sheet and are being amortized on a straight-line basis of $1.2 million per year over the life of the related firm transportation service agreement under which service commenced in June 2011. Also, in August 2011, Enogex and one of its five largest customers entered into new agreements, effective July 1, 2011, relating to the customer's gathering and processing volumes on the Oklahoma portion of Enogex's system. As a result of this transaction and as part of the new agreements, Enogex recorded $6.4 million in Deferred Revenues on the Company's Consolidated Balance Sheet at December 31, 2011. Processing revenues under the agreements are recognized based on the estimated average fee per MMBtu processed over the life of the agreements. Enogex expects to record additional deferred revenues during 2012.

Enogex, through OER, engages in energy marketing, trading, risk management and hedging activities related to the purchase and sale of natural gas as well as hedging activity related to the sale of natural gas and NGLs on behalf of the Company. 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. OER's transactions that qualify as derivatives are reflected at fair value with the resulting unrealized gains and losses recorded as PRM 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. Contracts resulting in delivery of a commodity 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.

Natural Gas Purchases

Estimates for gas purchases are based on estimated 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

OER 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 and are recorded at fair market value. OER's 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 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 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, 2011, unrealized mark-to-market gains were $2.9 million, none of which were calculated utilizing models. At December 31, 2011, 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.

Valuation of Assets

The application of business combination and impairment accounting requires Enogex to use significant estimates and assumptions in determining the fair value of assets and liabilities. The acquisition method of accounting for business combinations requires Enogex to estimate the fair value of assets acquired and liabilities assumed to allocate the proper amount of the purchase price consideration between goodwill and the assets that are depreciated and amortized. Enogex records intangible assets separately from goodwill and amortizes intangible assets with finite lives over their estimated useful life as determined by management. Enogex does not amortize goodwill but instead annually assesses goodwill for impairment.

In 2011, Enogex completed an acquisition accounted for as a business combination as discussed in Note 3 of Notes to Consolidated Financial Statements. As part of this acquisition, Enogex engaged the services of a third-party valuation expert to assist it in determining the fair value of the acquired assets and liabilities, including goodwill; however, the ultimate determination of those values is the responsibility of Enogex's management. Enogex bases its estimates on assumptions believed to be reasonable, but which are inherently uncertain. These valuations require the use of management's assumptions, which would not reflect unanticipated events and circumstances that may occur.

Depreciable Lives of Property, Plant and Equipment and Amortization Methodologies Related to Intangible Assets

The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets at the time the assets are placed in service. As circumstances warrant, useful lives are adjusted when changes in planned use, changes in estimated production lives of affiliated natural gas basins or other factors indicate that a different life would be more appropriate. Such changes could materially impact future depreciation expense. Changes in useful lives that do not result in the impairment of an asset are recognized prospectively. The computation of amortization expense on intangible assets requires judgment regarding the amortization method used. The intangible asset should be amortized over its useful life using a method of amortization that reflects the pattern in which the economic benefits of the intangible asset are consumed.

Natural Gas Inventory

Natural gas inventory is held by Enogex, through its transportation and storage business to provide operational support for its pipeline deliveries and through its marketing business to manage its leased storage capacity. In an effort to mitigate market price exposures, Enogex may enter into contracts or hedging instruments to protect the cash flows associated with its inventory. All natural gas inventory held by Enogex is valued using moving average cost and is recorded at the lower of cost or market. As part of its recurring marketing activity, OER injects and withdraws natural gas into and out of inventory under the terms of its storage capacity contracts. During the years ended December 31, 2011, 2010 and 2009, Enogex recorded write-downs to market value related to natural gas storage inventory of $4.8 million, $0.3 million and $6.1 million, respectively. The amount of Enogex's natural gas inventory was $23.7 million and $23.9 million at December 31, 2011 and 2010, respectively. The cost of gas associated with sales of natural gas storage inventory is presented in Cost of Goods Sold on the Consolidated Statements of Income.

Allowance for Uncollectible Accounts Receivable

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 Enogex 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 Enogex's transportation and storage, gathering and processing and marketing segments was less than $0.1 million and $0.3 million at December 31, 2011 and 2010, respectively.

Accounting Pronouncements

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

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 16 and 17 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.

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 including 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 their wastes, requiring remedial action to mitigate pollution conditions that may be caused by their operations or that are attributable to former operators, regulating future construction activities to mitigate harm to threatened or endangered species and requiring the installation and operation of pollution control equipment. 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. OG&E and Enogex believe that their operations are in substantial compliance with current Federal, state and local environmental standards.

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 is expected to increase the cost of conducting business.

OG&E expects that environmental expenditures necessary to comply with the environmental laws and regulations discussed below 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.

Of the Company's capital expenditures budgeted for 2012, $34.4 million are to comply with environmental laws and regulations, of which $33.7 million and $0.7 million are related to OG&E and Enogex, respectively. Of the Company's capital expenditures budgeted for 2013, $36.0 million are to comply with environmental laws and regulations, of which $35.3 million and $0.7 million are related to OG&E and Enogex, respectively. The Company's management believes that all of its operations are in substantial compliance with current Federal, state and local environmental standards. It is estimated that OG&E's and Enogex's total expenditures for capital, operating, maintenance and other costs associated with environmental quality will be $51.6 million and $6.2 million, respectively, in 2012 as compared to $24.0 million and $6.5 million, respectively, in 2011. Management continues to evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

Air

Federal Clean Air Act Overview

OG&E’s and Enogex’s operations are subject to the Federal Clean Air Act, as amended, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including electric generating units, natural gas processing plants and compressor stations, and also impose various monitoring and reporting requirements. Such laws and regulations may require that OG&E and Enogex obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations or install emission control equipment. 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.

Regional Haze Control Measures

On June 15, 2005, the EPA issued final amendments to its 1999 regional haze rule. Regional haze is visibility impairment caused by the cumulative air pollutant emissions from numerous sources over a wide geographic area. These regulations are intended to protect visibility in certain national parks and wilderness 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.

As required by the Federal regional haze rule, the state of Oklahoma evaluated the installation of BART to reduce emissions that cause or contribute to regional haze from certain sources within the state that were built between 1962 and 1977. Certain of OG&E’s units at the Horseshoe Lake, Seminole, Muskogee and Sooner generating stations were evaluated for BART. On February 18, 2010, Oklahoma submitted its SIP to the EPA, which set forth the state's plan for compliance with the Federal regional haze rule. The SIP was subject to the EPA's review and approval.

The Oklahoma SIP included requirements for reducing emissions of NOX and SO2 from OG&E's seven BART-eligible units at the Seminole, Muskogee and Sooner generating stations. The SIP also included a waiver from BART requirements for all eligible units at the Horseshoe Lake generating station based on air modeling that showed no significant impact on visibility in nearby national parks and wilderness areas. The SIP concluded that BART for reducing NOX emissions at all of the subject units should be the installation of low NOX burners (overfire air and flue gas recirculation was also required on two of the units) and set forth associated NOX emission rates and limits. OG&E preliminarily estimates that the total cost of installing and operating these NOX controls on all covered units, based on recent industry experience and past projects, will be between $70 million and $130 million. With respect to SO2 emissions, the SIP included an agreement between the ODEQ and OG&E that established BART for SO2 control at four coal-fired units located at OG&E's Sooner and Muskogee generating stations as the continued use of low sulfur coal (along with associated emission rates and limits). The SIP specifically rejected the installation and operation of Dry Scrubbers as BART for SO2 control from these units because the state determined that Dry Scrubbers were not cost effective on these units.

On December 28, 2011, the EPA rejected portions of the Oklahoma SIP and issued a Federal implementation plan. While the EPA accepted Oklahoma's BART determination for NOX in the SIP, it rejected the SO2 BART determination with respect to the four coal-fired units at the Sooner and Muskogee generating stations. In its place, the EPA is requiring that OG&E meet an SO2 emission rate of 0.06 pounds per MMBtu within five years. OG&E could meet the proposed standard by either installing and operating Dry Scrubbers or fuel switching at the four affected units. OG&E estimates that installing Dry Scrubbers on these units would cost OG&E more than $1.0 billion. OG&E and the state of Oklahoma expect to file an administrative stay request with the EPA. OG&E and the state of Oklahoma have also announced that they intend to petition for review of this determination in the U.S. Court of Appeals for the Tenth Circuit. Neither the outcome of the appeal nor the timing and amount of any required expenditures for pollution control equipment can be predicted with any certainty at this time.

Cross-State Air Pollution Rule

On July 7, 2011, the EPA finalized its Cross-State Air Pollution Rule to replace the former Clean Air Interstate Rule that was remanded by a Federal court as a result of legal challenges. The final rule requires 27 states to reduce power plant emissions that contribute to ozone and particulate matter pollution in other states. On December 27, 2011, the EPA published a supplemental rule which makes six additional states, including Oklahoma, subject to the Cross-State Air Pollution Rule for NOX emissions during the ozone-season from May 1 through September 30. Under the rule, OG&E is required to reduce ozone-season NOX emissions from its electrical generating units within the state beginning in 2012. The Cross-State Air Pollution Rule is currently being challenged in court by numerous states and power generators. On December 30, 2011, the U.S. Court of Appeals issued a stay of the rule and requested proposals for accelerated briefing to allow the merits of the case to be heard by April 2012. On February 6, 2012, the EPA issued a notice indicating that the supplemental rule is also included in the stay discussed above. OG&E cannot predict the outcome of such challenges and is evaluating what emission controls would be necessary to meet the standards, its ability to comply with the standards in the timeframe proposed by the EPA and the associated costs, which could be significant.

Hazardous Air Pollutants Emission Standards

On December 16, 2011, the EPA signed the Maximum Achievable Control Technology regulations governing emissions of certain hazardous air pollutants from electric generating units. The final rule includes numerical standards for particulate matter (as a surrogate for toxic metals), hydrogen chloride and mercury emissions from coal-fired boilers. In addition, the regulations include work practice standards for dioxins and furans. Compliance is required within three years after the effective date of the rule with a possibility of a one year extension. The effective date of the rule has not been established, but it is expected to be during the second quarter of 2012. The final rule could be appealed after it is published. OG&E cannot predict the outcome of any such appeals and is evaluating the regulations and what emission controls would be necessary to meet the standards and the associated costs, which could be significant.

Notice of Violation

In July 2008, OG&E received a request for information from the EPA regarding Federal 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 Federal Clean Air Act's new source review process. In January 2012, OG&E received a supplemental request for an update of the previously provided information and for some additional information not previously requested. OG&E believes it has acted in full compliance with the Federal Clean Air Act and new source review process and is cooperating with the EPA. On April 26, 2011, the EPA issued a notice of violation alleging that 13 projects that occurred at OG&E's Muskogee and Sooner generating plants between 1993 and 2006 without the required new source review permits. The notice of violation also alleges that OG&E's visible emissions at its Muskogee and Sooner generating plants are not in accordance with applicable new source performance standards (See Part I, Item 3 – Legal Proceedings – Opacity Notice for a related discussion). OG&E has met with the EPA regarding the notice but cannot predict at this time what, if any, further actions may be necessary as a result of the notice. The EPA could seek to require OG&E to install additional pollution control equipment and pay fines and significant penalties as a result of the allegations in the notice of violation. Section 113 of the Federal Clean Air Act (along with the Federal Civil Penalties Inflation Adjustment Act of 1996) provides for civil penalties as much as $37,500 per day for each violation.

National Ambient Air Quality Standards

The EPA is required to set NAAQS for certain pollutants considered to be harmful to public health or the environment. On June 2, 2010, the EPA released its final rule strengthening its NAAQS for SO2. The final rule revokes the existing 24-hour and annual standards and establishes a new lower one-hour standard at a level of 75 parts per billion. The EPA intends to complete attainment designations within two years of promulgation of the revised SO2 standard, which is expected by June 2012. States with areas designated nonattainment in 2012 would need to submit a SIP to the EPA by early 2014 outlining actions that those states will take to meet the EPA's revised standards on or before August 2017. The Company will continue to monitor the EPA's attainment designation activities.

On January 25, 2010, the EPA released a rule strengthening the NAAQS for oxides of nitrogen as measured by nitrogen dioxide which became effective March 26, 2011. The rule establishes a new one-hour standard and monitoring requirements, as well as an approach for implementing the new standard. Oklahoma is currently in attainment with the new standard and it is anticipated that Oklahoma will be designated "unclassifiable" in 2012 because the new monitoring requirements will not yet be fully implemented. After the new monitoring network is deployed and has collected three years of air quality data, the EPA will re-designate areas in 2016 or 2017 based on the new data. It is currently anticipated that Oklahoma will be designated "attainment" at that time.

On September 21, 2006, the EPA lowered the 24-hour fine particulate NAAQS while retaining the annual NAAQS at its existing level and promulgated a new standard for inhalable coarse particulates. Based on past monitoring data, it appears that Oklahoma may be able to remain in attainment with these standards. However if parts of Oklahoma do become "non-attainment", reductions in emissions from OG&E's coal-fired boilers could be required which may result in significant capital and operating expenditures.

The EPA has designated Oklahoma as being "in attainment" with the current NAAQS for ozone. In March 2008, the EPA issued a final rule lowering the ambient primary and secondary ozone standards NAAQS from current levels. Before Oklahoma's designations of areas as attaining or not attaining the 2008 ozone standards were complete, the EPA announced an intent to reconsider these standards and issue even lower ozone NAAQS. President Obama, however, requested that the EPA refrain from issuing revised standards until 2013. The EPA has indicated that it will comply with the President's request. As a result, it is expected that Oklahoma will proceed with the designation of areas as attaining or not attaining the ozone standards established in the 2008 rule. Neither the outcome nor timing of the ozone NAAQS attainment area designation process nor its impact on the Company can be determined with any certainty at this time.

Acid Rain Program

The Federal Clean Air Act includes an Acid Rain Program. The goal of the Acid Rain Program is to achieve environmental and public health benefits through reductions in SO2 and NOX emissions, which are the primary causes of acid rain. To achieve this goal, the program employs both traditional and market-based approaches for controlling air pollution.

The Acid Rain Program introduces an allowance trading system that uses the free market to reduce pollution. Under this system, affected utility units are allocated allowances based on their historic fuel consumption and a specific emissions rate. Each allowance permits a unit to emit one ton of SO2 from the chimney during or after a specified year. For each ton of SO2 emitted in a given year, one allowance is retired, that is, it can no longer be used. Allowances may be bought, sold or banked.

During Phase II of the program (now in effect), the Federal Clean Air Act set a permanent ceiling (or cap) of 8.95 million total annual allowances allocated to utilities. This cap firmly restricts emissions and ensures that environmental benefits will be achieved and maintained. Due to OG&E's earlier decision to burn low sulfur coal, these restrictions have had no significant financial impact.

The Acid Rain Program also focuses on one set of sources that emit NOX, coal-fired electric utility boilers. As with the SO2 emission reduction requirements, the NOX program was implemented in two phases, beginning in 1996 and 2000. The NOX program embodies many of the same principles of the SO2 trading program. However, it does not cap NOX emissions as the SO2 program does, nor does it utilize an allowance trading system.

Emission limitations for NOX focus on the emission rate to be achieved (expressed in pounds of NOX per MMBtu of heat input). In general, two options for compliance with the emission limitations are provided: compliance with an individual emission rate for a boiler; or averaging of emission rates over two or more units to meet an overall emission rate limitation.

Since becoming subject to the Acid Rain Program, OG&E has met all obligations and limitations requirements.

Climate Change and Greenhouse Gas Emissions

Emissions of greenhouse gases, including carbon dioxide, sulfur hexafluoride and methane, may be contributing to warming of the Earth's atmosphere. There are various international agreements that restrict greenhouse gas emissions, but none of them have a binding effect on sources located in the United States. The U.S. Congress has not passed legislation to reduce emissions of greenhouse gases and the future prospects for any such legislation are uncertain. Several states 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. Oklahoma, Arkansas and Texas are not among them.

In the absence of new Federal legislation, the EPA is regulating greenhouse gas emissions from stationary sources using its existing legal authority. On September 22, 2009, the EPA announced the adoption of the first comprehensive national system for reporting emissions of carbon dioxide and other greenhouse gases produced by major sources in the United States. The reporting requirements apply to large direct emitters of greenhouse gases with emissions equal to or greater than a threshold of 25,000 metric tons per year, which includes certain OG&E and Enogex facilities. Pursuant to the rule, the Company began collecting data on January 1, 2010 and submitted its first annual report to the EPA by the September 30, 2011 deadline. For petroleum and natural gas facilities, data collection began on January 1, 2011, with the first annual report due to the EPA on September 28, 2012. OG&E already reports quarterly its carbon dioxide emissions from generating units subject to the Federal Acid Rain Program.

On June 3, 2010, the EPA issued a final rule that makes certain sources subject to permitting requirements for greenhouse gas emissions. This rule now requires sources that emit greater than 100,000 tons per year of greenhouse gases to obtain a permit for those emissions, even if they are not otherwise required to obtain a new or modified permit. Such sources may have to install best available control technology to control greenhouse gas emissions pursuant to this rule. Also, in December 2010, the EPA entered into an agreement to settle litigation brought by states and environmental groups whereby the EPA agreed to issue New Source Performance Standards for greenhouse gas emissions from certain new and modified electric generating units and emissions guidelines for existing units over the next two years. Pursuant to this settlement agreement, the EPA agreed to issue proposed rules during the fourth quarter of 2011 and final rules by mid-2012. The EPA has not yet issued proposed rules and has sought to extend the deadlines for issuing the rules.

Another impetus for addressing climate change is litigation relating to greenhouse gas emissions and pressure for greenhouse gas emission reductions from investor organizations and the international community. In at least three Federal court cases, nuisance-type claims have been asserted against emitters of carbon dioxide, including several utility companies, alleging that such emissions contribute to global warming. On June 20, 2011, the U.S. Supreme Court issued a decision that bars state and private parties from bringing Federal common law nuisance actions against electrical utility companies based on their alleged contribution to climate change. The Supreme Court's decision, which did not address state law claims, is expected to affect other pending Federal climate change litigation. Although OG&E is not a defendant in any of these proceedings, additional litigation in Federal and state courts over climate change issues is continuing.

OG&E is continuing to evaluate various options for reducing, avoiding, offsetting or sequestering its carbon dioxide emissions. OG&E is a partner in the EPA Sulfur Hexafluoride Voluntary Reduction Program, and 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 facilities to address climate change, this could result in significant additional compliance costs that would affect the Company’s future consolidated financial position, results of operations and cash flows if such costs are not recovered through regulated rates.

Endangered Species

Certain Federal laws, including the Bald and Golden Eagle Protection Act, the Migratory Bird Treaty Act and the Endangered Species Act, provide special protection to certain designated species. These laws and any state equivalents provide for significant civil and criminal penalties for unpermitted activities that result in harm to or harassment of certain protected animals and plants, including damage to their habitats. If such species are located in an area in which the Company conducts operations, or if additional species in those areas, such as the lesser prairie chicken, become subject to protection, the Company’s operations and development projects, particularly transmission projects, wind projects or pipeline operations, could be restricted or delayed, or the Company could be required to implement expensive mitigation measures.

Waste

OG&E's and Enogex's operations generate hazardous wastes that are subject to the Federal Resource Conservation and Recovery Act of 1976 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 and occasional larger quantities from periodic power generation related activities. These wastes are treated, stored and disposed at facilities that are permitted to manage them.

In June 2010, the EPA proposed new rules under Federal Resource Conservation and Recovery Act of 1976 that could alter the classification of OG&E's coal-fired power plants as conditionally exempt hazardous waste generators and make the management of coal ash more costly. The extent to which the EPA intends to regulate coal ash is uncertain due to the fact that the new rules propose to regulate coal ash as a hazardous waste or as a nonhazardous solid waste. In November 2010, OG&E submitted written comments opposing the regulation of coal ash as a hazardous waste while supporting its regulation as a nonhazardous waste. The EPA continues to consider numerous comments received on the proposal and has stated that it plans to issue a final rule regarding the regulation of coal ash in late 2012.

OG&E has sought and will continue to seek pollution prevention opportunities and to evaluate the effectiveness of its waste reduction, reuse and recycling efforts. In 2011, OG&E obtained refunds of $5.2 million from the recycling of scrap metal, salvaged transformers and used transformer oil. 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.

For Enogex, the Federal Resource Conservation and Recovery Act of 1976 currently exempts many natural gas gathering and field processing wastes from classification as hazardous waste. However, these oil and gas exploration and production wastes may still be regulated under state law or the less stringent solid waste requirements of the Federal Resource Conservation and Recovery Act of 1976. The transportation of natural gas in pipelines may also generate some hazardous wastes that are subject to the Federal Resource Conservation and Recovery Act of 1976 or comparable state law requirements.

Water

OG&E's and Enogex's operations are subject to the Federal 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, is prohibited unless authorized by a permit or other agency approval. The Federal 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. Existing cooling water intake structures are regulated under the Federal Clean Water Act to minimize their impact on the environment.

With respect to cooling water intake structures, Section 316(b) of the Federal Clean Water Act requires that their location, design, construction and capacity reflect the "best available technology" for minimizing their adverse environmental impact via the impingement and entrainment of aquatic organisms. In March 2011, the EPA proposed rules to implement Section 316(b). On August 18, 2011, OG&E filed comments with the EPA on the proposed rules. OG&E anticipates that the proposed rules will be finalized in mid-2012. In the interim, the state of Oklahoma requires OG&E to implement best management practices related to the operation and maintenance of its existing cooling water intake structures as a condition of renewing its discharge permits. Once the EPA promulgates the final rules, OG&E may incur additional capital and/or operating costs to comply with them. The costs of complying with the final water intake standards are not currently determinable, but could be significant.

Site Remediation

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 and comparable state laws impose liability, without regard to the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Because OG&E and Enogex utilize various products and generate wastes that are considered hazardous substances for purposes of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, OG&E and Enogex could be subject to 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 a significant impact to OG&E or Enogex.

For a further discussion regarding contingencies relating to environmental laws and regulations, see Note 16 of Notes to Consolidated Financial Statements.

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 interest rates and commodity prices. The Company's exposure to changes in interest rates relates primarily to short-term variable-rate debt and commercial paper. The Company is exposed to commodity prices in its operations.

Risk Committee and Oversight

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

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

The Company also has a Corporate Risk Management Department led by the Company's 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 Company's 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 market risk management are being followed. Some of the measures in these policies include value-at-risk limits, position limits, tenor limits and stop loss limits.

Interest Rate Risk

The Company's exposure to changes in interest rates primarily relates to short-term variable-rate debt and commercial paper. The Company manages its interest rate exposure by monitoring and limiting the effects of market changes in interest rates. The Company utilizes interest rate derivatives to alter interest rate exposure in an attempt to reduce the effects of these changes. 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 estimates of current rates available for similar issues with similar maturities. 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)*	2012	2013	2014	2015	2016	Thereafter	Total	12/31/11 Fair Value
Fixed-rate debt (A)								
Principal amount	$ —	$ —	$ 300.0	$ —	$ 110.0	$ 2,050.0	$ 2,460.0	$ 2,990.2
Weighted-average interest rate	—	—	6.25%	—	5.15%	6.40%	6.32%	
Variable-rate debt (B)								
Principal amount	—	—	—	—	150.0	$ 135.4	$ 285.4	$ 285.4
Weighted-average interest rate	—	—	—	—	1.65%	0.22%	0.97%	

(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 incurred by the Company would change interest expense by $2.9 million annually.

Commodity Price Risk

The commodity price risks inherent in the Company's commodity price 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 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 are conducted throughout the year subject to $2.5 million daily and monthly trading stop loss limits set by the Risk Oversight Committee. The loss exposure from trading activities is measured primarily using value-at-risk, which estimates the potential losses the trading activities could incur over a specified time horizon and confidence level. Currently, the Company utilizes the variance/co-variance method for calculating value-at-risk, assuming a 95 percent confidence level. The value-at-risk limit set by the Risk Oversight Committee for the Company's trading activities is currently $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 commodity price 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. Commodity price risk is estimated as the potential loss in fair value resulting from a hypothetical 20 percent adverse change in quoted market prices. The result of this analysis, which may differ from actual results, reflects net commodity price risk to be $0.1 million at December 31, 2011. This amount represents the Company's exposure, net of the ArcLight group's proportional share.

Commodity price risk is present in the Company's non-trading activities because changes in the prices of natural gas, NGLs and NGLs processing spreads have a direct effect on the compensation the Company receives for operating some of its assets. These prices are subject to fluctuations resulting from changes in supply and demand. To partially reduce non-trading commodity price risk, the Company utilizes risk mitigation tools such as default processing fees and ethane rejection capabilities to protect its downside exposure while maintaining its upside potential. Additionally, 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 commodity price risk created by 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. Commodity price risk is estimated as the potential loss in fair value resulting from a hypothetical 20 percent adverse change in quoted market prices. The result of this analysis, which may differ from actual results, reflects net commodity price risk to be $32.0 million at December 31, 2011. This amount represents the Company's exposure, net of the ArcLight group's proportional share.

Item 8. Financial Statements.

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

Year ended December 31 *(In millions except per share data)*	**2011**	2010	2009
OPERATING REVENUES			
Electric Utility operating revenues	**$ 2,211.5**	$ 2,109.9	$ 1,751.2
Natural Gas Midstream Operations operating revenues	**1,704.4**	1,607.0	1,118.5
Total operating revenues	**3,915.9**	3,716.9	2,869.7
COST OF GOODS SOLD (exclusive of depreciation and amortization shown below)			
Electric Utility cost of goods sold	**966.0**	952.6	748.7
Natural Gas Midstream Operations cost of goods sold	**1,311.9**	1,234.8	809.0
Total cost of goods sold	**2,277.9**	2,187.4	1,557.7
Gross margin on revenues	**1,638.0**	1,529.5	1,312.0
OPERATING EXPENSES			
Other operation and maintenance	**581.2**	549.8	466.8
Depreciation and amortization	**307.1**	291.3	262.6
Impairment of assets	**6.3**	1.1	3.1
Gain on insurance proceeds	**(3.0)**	—	—
Taxes other than income	**99.7**	93.4	87.6
Total operating expenses	**991.3**	935.6	820.1
OPERATING INCOME	**646.7**	593.9	491.9
OTHER INCOME (EXPENSE)			
Interest income	**0.5**	—	1.4
Allowance for equity funds used during construction	**20.4**	11.4	15.1
Other income	**19.3**	13.7	27.5
Other expense	**(21.7)**	(17.9)	(16.3)
Net other income	**18.5**	7.2	27.7
INTEREST EXPENSE			
Interest on long-term debt	**146.1**	139.3	137.3
Allowance for borrowed funds used during construction	**(10.4)**	(5.5)	(8.3)
Interest on short-term debt and other interest charges	**5.2**	5.9	8.4
Interest expense	**140.9**	139.7	137.4
INCOME BEFORE TAXES	**524.3**	461.4	382.2
INCOME TAX EXPENSE	**160.7**	161.0	121.1
NET INCOME	**363.6**	300.4	261.1
Less: Net income attributable to noncontrolling interests	**20.7**	5.1	2.8
NET INCOME ATTRIBUTABLE TO OGE ENERGY	**$ 342.9**	$ 295.3	$ 258.3
BASIC AVERAGE COMMON SHARES OUTSTANDING	**97.9**	97.3	96.2
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**99.2**	98.9	97.2
BASIC EARNINGS PER AVERAGE COMMON SHARE			
ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS	**$ 3.50**	$ 3.03	$ 2.68
DILUTED EARNINGS PER AVERAGE COMMON SHARE			
ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS	**$ 3.45**	$ 2.99	$ 2.66
DIVIDENDS DECLARED PER COMMON SHARE	**$ 1.5175**	$ 1.4625	$ 1.4275

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31 *(In millions)*	**2011**	2010	2009
Net income	**$ 363.6**	$ 300.4	$ 261.1
Other comprehensive income (loss), net of tax			
Pension Plan and Restoration of Retirement Income Plan:			
Amortization of deferred net loss, net of tax of $1.4 million, $1.2 million and $2.0 million, respectively	**2.5**	1.3	3.2
Net gain (loss) arising during the period, net of tax of ($6.7) million, $4.4 million and $0.4 million, respectively	**(13.5)**	7.6	0.6
Amortization of prior service cost, net of tax of $0.2 million, $0.1 million and $0.1 million, respectively	**0.4**	0.2	0.1
Prior service cost arising during the period, net of tax of $0, $0 and ($0.2) million, respectively	**—**	—	(0.3)
Postretirement plans:			
Amortization of deferred net loss, net of tax of ($1.6) million, $0.6 million and $0.7 million, respectively	**1.8**	1.2	0.9
Net loss arising during the period, net of tax of ($3.1) million, ($2.4) million and ($4.1) million, respectively	**(3.6)**	(4.1)	(6.3)
Amortization of deferred net transition obligation, net of tax of $0.1 million, $0.1 million and $0.1 million, respectively	**0.2**	0.1	0.1
Amortization of prior service cost, net of tax of ($1.6) million, $0.1 million and $0.1 million, respectively	**(1.8)**	—	0.2
Prior service cost arising during the period, net of tax of $9.5 million, $0 and $0, respectively	**10.8**	—	—
Deferred commodity contracts hedging losses reclassified in net income, net of tax of $12.6 million, $9.9 million and $4.7 million, respectively	**27.6**	18.5	7.5
Deferred commodity contracts hedging gains (losses), net of tax of ($1.7) million, ($8.5) million and ($42.6) million, respectively	**(4.8)**	(16.3)	(67.3)
Deferred interest rate swaps hedging gains, net of tax of $0.2 million, $0.2 million and $0.2 million, respectively	**0.3**	0.2	0.3
Other comprehensive income (loss), net of tax	**19.9**	8.7	(61.0)
Comprehensive income (loss)	**383.5**	309.1	200.1
Less: Comprehensive income attributable to noncontrolling interest for sale of equity investment	**(3.2)**	(6.2)	—
Less: Comprehensive income attributable to noncontrolling interests	**24.2**	5.5	2.8
Total comprehensive income (loss) attributable to OGE Energy	**$ 362.5**	$ 309.8	$ 197.3

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 *(In millions)*	**2011**	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	**$ 363.6**	$ 300.4	$ 261.1
Adjustments to reconcile net income to net cash provided from operating activities			
Depreciation and amortization	**307.1**	291.3	262.6
Impairment of assets	**6.3**	1.1	3.1
Deferred income taxes and investment tax credits, net	**166.0**	146.4	269.8
Allowance for equity funds used during construction	**(20.4)**	(11.4)	(15.1)
Gain on disposition and abandonment of assets	**(2.7)**	—	—
Gain on insurance proceeds	**(3.0)**	—	—
Stock-based compensation expense	**7.8**	7.4	4.1
Excess tax benefit on stock-based compensation	**—**	(0.7)	(3.3)
Price risk management assets	**(1.7)**	3.9	27.8
Price risk management liabilities	**19.0**	8.5	(88.7)
Regulatory assets	**14.0**	24.1	20.2
Regulatory liabilities	**(1.9)**	(12.4)	(17.5)
Other assets	**(7.0)**	6.3	(3.5)
Other liabilities	**(37.4)**	(37.0)	(37.7)
Change in certain current assets and liabilities			
Accounts receivable, net	**(48.0)**	11.9	(3.3)
Accrued unbilled revenues	**(2.5)**	0.4	(10.2)
Income taxes receivable	**(3.6)**	153.0	(157.7)
Fuel, materials and supplies inventories	**54.2**	(45.2)	(36.1)
Gas imbalance assets	**0.7**	0.7	3.0
Fuel clause under recoveries	**(0.8)**	(0.7)	23.7
Other current assets	**(7.2)**	(5.9)	(1.4)
Accounts payable	**34.5**	59.2	(17.2)
Gas imbalance liabilities	**3.1**	(5.3)	(12.9)
Fuel clause over recoveries	**(22.2)**	(157.6)	178.9
Other current liabilities	**16.0**	44.1	4.8
Net Cash Provided from Operating Activities	**833.9**	782.5	654.5
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures (less allowance for equity funds used during construction)	**(1,270.4)**	(879.9)	(847.8)
Acquisition of gathering assets	**(200.4)**	—	—
Reimbursement of capital expenditures	**49.6**	31.5	38.8
Proceeds from sale of assets	**18.0**	2.3	—
Proceeds from insurance	**7.4**	—	—
Other investing activities	**—**	—	0.5
Net Cash Used in Investing Activities	**(1,395.8)**	(846.1)	(808.5)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from long-term debt	**246.3**	246.2	444.8
Contributions from noncontrolling interest partners	**216.4**	183.2	—
Proceeds from line of credit	**150.0**	115.0	80.0
Increase (decrease) in short-term debt	**132.1**	(30.0)	(123.0)
Issuance of common stock	**14.8**	16.9	79.6
Excess tax benefit on stock-based compensation	**—**	0.7	3.3
Retirement of long-term debt	**—**	(289.2)	(110.8)
Purchase of treasury stock	**(6.2)**	—	—
Distributions to noncontrolling interest partners	**(17.4)**	(4.0)	—
Repayment of line of credit	**(25.0)**	(90.0)	(200.0)
Dividends paid on common stock	**(146.8)**	(141.0)	(136.2)
Net Cash Provided from Financing Activities	**564.2**	7.8	37.7
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**2.3**	(55.8)	(116.3)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**2.3**	58.1	174.4
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 4.6**	$ 2.3	$ 58.1

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

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS

December 31 *(In millions)*	**2011**	2010
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 4.6**	$ 2.3
Accounts receivable, less reserve of $3.8 and $1.9, respectively	**322.5**	277.9
Accrued unbilled revenues	**59.3**	56.8
Income taxes receivable	**8.3**	4.7
Fuel inventories	**100.7**	158.8
Materials and supplies, at average cost	**87.2**	83.3
Price risk management	**3.5**	1.4
Gas imbalances	**1.8**	2.5
Deferred income taxes	**32.1**	18.7
Fuel clause under recoveries	**1.8**	1.0
Other	**30.9**	24.7
Total current assets	**652.7**	632.1
OTHER PROPERTY AND INVESTMENTS, at cost	**46.7**	44.9
PROPERTY, PLANT AND EQUIPMENT		
In service	**10,315.9**	9,188.0
Construction work in progress	**499.0**	460.0
Total property, plant and equipment	**10,814.9**	9,648.0
Less accumulated depreciation	**3,340.9**	3,183.6
Net property, plant and equipment	**7,474.0**	6,464.4
DEFERRED CHARGES AND OTHER ASSETS		
Regulatory assets	**507.9**	489.4
Intangible assets, net	**137.0**	2.8
Goodwill	**39.4**	—
Price risk management	**0.3**	0.8
Other	**48.0**	34.7
Total deferred charges and other assets	**732.6**	527.7
TOTAL ASSETS	**$ 8,906.0**	$ 7,669.1

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

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS (Continued)

December 31 *(In millions)*	**2011**	2010
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 277.1**	$ 145.0
Accounts payable	**388.0**	321.7
Dividends payable	**38.5**	36.6
Customer deposits	**67.6**	67.0
Accrued taxes	**42.3**	39.3
Accrued interest	**54.8**	53.1
Accrued compensation	**47.8**	43.3
Price risk management	**0.4**	16.8
Gas imbalances	**9.8**	6.7
Fuel clause over recoveries	**7.7**	29.9
Other	**64.5**	55.1
Total current liabilities	**998.5**	814.5
LONG-TERM DEBT	**2,737.1**	2,362.9
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued benefit obligations	**360.8**	372.4
Deferred income taxes	**1,651.4**	1,434.8
Deferred investment tax credits	**6.1**	9.4
Regulatory liabilities	**230.7**	193.1
Price risk management	**0.1**	—
Deferred revenues	**40.8**	36.7
Other	**61.2**	45.3
Total deferred credits and other liabilities	**2,351.1**	2,091.7
Total liabilities	**6,086.7**	5,269.1
COMMITMENTS AND CONTINGENCIES (NOTE 16)		
STOCKHOLDERS' EQUITY		
Common stockholders' equity	**1,035.3**	969.2
Retained earnings	**1,574.8**	1,380.6
Accumulated other comprehensive loss, net of tax	**(40.6)**	(60.2)
Treasury stock, at cost	**(6.2)**	—
Total OGE Energy stockholders' equity	**2,563.3**	2,289.6
Noncontrolling interests	**256.0**	110.4
Total stockholders' equity	**2,819.3**	2,400.0
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 8,906.0**	$ 7,669.1

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 *(In millions)*			**2011**	2010
STOCKHOLDERS' EQUITY				
Common stock, par value $0.01 per share; authorized 225.0 shares; and outstanding 98.1 and 97.6 shares, respectively			**$ 1.0**	$ 1.0
Premium on common stock			**1,034.3**	968.2
Retained earnings			**1,574.8**	1,380.6
Accumulated other comprehensive loss, net of tax			**(40.6)**	(60.2)
Treasury stock, at cost, 0.1 and 0 shares, respectively			**(6.2)**	—
Total OGE Energy stockholders' equity			**2,563.3**	2,289.6
Noncontrolling interest			**256.0**	110.4
Total stockholders' equity			**2,819.3**	2,400.0
LONG-TERM DEBT				
	SERIES	DUE DATE		
	Senior Notes - OGE Energy			
	5.00%	Senior Notes, Series Due November 15, 2014	**100.0**	100.0
	Unamortized discount		**(0.2)**	(0.3)
	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**	250.0
	8.25%	Senior Notes, Series Due January 15, 2019	**250.0**	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**	200.0
	5.85%	Senior Notes, Series Due June 1, 2040	**250.0**	250.0
	5.25%	Senior Notes, Series Due May 15, 2041	**250.0**	—
	Other Bonds - OG&E			
	0.22% - 0.44%	Garfield Industrial Authority, January 1, 2025	**47.0**	47.0
	0.20% - 0.44%	Muskogee Industrial Authority, January 1, 2025	**32.4**	32.4
	0.24% - 0.50%	Muskogee Industrial Authority, June 1, 2027	**56.0**	56.0
	Unamortized discount		**(6.2)**	(5.0)
	Enogex			
	1.65%	Enogex LLC Revolving Credit Agreement Due December 13, 2016	**150.0**	25.0
	6.875%	Senior Notes, Series Due July 15, 2014	**200.0**	200.0
	6.25%	Senior Notes, Series Due March 15, 2020	**250.0**	250.0
	Unamortized discount		**(1.9)**	(2.2)
Total long-term debt			**2,737.1**	2,362.9
Total Capitalization			**$ 5,556.4**	$ 4,762.9

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 Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Treasury Stock	Total
Balance at December 31, 2008	$ 0.9	$ 802.0	$ 1,107.6	$ (13.7)	$ 17.2	$ —	$ 1,914.0
Comprehensive income (loss)							
Net income	—	—	258.3	—	2.8	—	261.1
Other comprehensive income (loss), net of tax	—	—	—	(61.0)	—	—	(61.0)
Comprehensive income (loss)	—	—	258.3	(61.0)	2.8	—	200.1
Dividends declared on common stock	—	—	(138.1)	—	—	—	(138.1)
Issuance of common stock	0.1	79.5	—	—	—	—	79.6
Stock-based compensation	—	5.2	—	—	—	—	5.2
Balance at December 31, 2009	$ 1.0	$ 886.7	$ 1,227.8	$ (74.7)	$ 20.0	$ —	$ 2,060.8
Comprehensive income (loss)							
Net income	—	—	295.3	—	5.1	—	300.4
Other comprehensive income (loss), net of tax	—	—	—	14.5	(5.8)	—	8.7
Comprehensive income (loss)	—	—	295.3	14.5	(0.7)	—	309.1
Dividends declared on common stock	—	—	(142.5)	—	—	—	(142.5)
Issuance of common stock	—	17.0	—	—	—	—	17.0
Stock-based compensation	—	10.4	—	—	—	—	10.4
Contributions from noncontrolling interest partner	—	88.1	—	—	95.1	—	183.2
Deferred income taxes attributable to contributions from noncontrolling interest partner	—	(34.0)	—	—	—	—	(34.0)
Distributions to noncontrolling interest partner	—	—	—	—	(4.0)	—	(4.0)
Balance at December 31, 2010	$ 1.0	$ 968.2	$ 1,380.6	$ (60.2)	$ 110.4	$ —	$ 2,400.0
Comprehensive income (loss)							
Net income	**—**	**—**	**342.9**	**—**	**20.7**	**—**	**363.6**
Other comprehensive income (loss), net of tax	**—**	**—**	**—**	**19.6**	**0.3**	**—**	**19.9**
Comprehensive income (loss)	**—**	**—**	**342.9**	**19.6**	**21.0**	**—**	**383.5**
Dividends declared on common stock	**—**	**—**	**(148.7)**	**—**	**—**	**—**	**(148.7)**
Issuance of common stock	**—**	**14.8**	**—**	**—**	**—**	**—**	**14.8**
Stock-based compensation	**—**	**5.8**	**—**	**—**	**—**	**—**	**5.8**
Contributions from noncontrolling interest partners	**—**	**74.4**	**—**	**—**	**142.0**	**—**	**216.4**
Distributions to noncontrolling interest partners	**—**	**—**	**—**	**—**	**(17.4)**	**—**	**(17.4)**
Deferred income taxes attributable to contributions from noncontrolling interest partners	**—**	**(28.9)**	**—**	**—**	**—**	**—**	**(28.9)**
Purchase of treasury stock	**—**	**—**	**—**	**—**	**—**	**(6.2)**	**(6.2)**
Balance at December 31, 2011	**$ 1.0**	**$ 1,034.3**	**$ 1,574.8**	**$ (40.6)**	**$ 256.0**	**$ (6.2)**	**$ 2,819.3**

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

OGE ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Organization

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 OG&E and are subject to regulation by the OCC, the APSC and the 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 natural gas business in 1928 and is no longer engaged in the natural gas distribution business.

Enogex is a provider of integrated natural gas midstream services. Enogex is engaged in the business of gathering, processing, transporting, storing and marketing natural gas. Most of Enogex's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. Enogex's operations are organized into three business segments: (i) natural gas transportation and storage, (ii) natural gas gathering and processing and (iii) natural gas marketing. At December 31, 2011, the Company indirectly owns an 81.3 percent membership interest in Enogex Holdings, which in turn owns all of the membership interests in Enogex LLC, a Delaware single-member limited liability company (see Note 4). The Company continues to consolidate Enogex Holdings in its Consolidated Financial Statements as OGE Energy has a controlling financial interest over the operations of Enogex Holdings. Also, Enogex LLC holds a 50 percent ownership interest in Atoka. The Company consolidates Atoka in its Consolidated Financial Statements as Enogex acts as the managing member of Atoka and has control over the operations of Atoka.

OGE Energy charges 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, either as overhead based primarily on labor costs or using 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. OGE Energy adopted the Distrigas method in January 1996 as a result of a recommendation by the OCC Staff. OGE Energy believes this method provides a reasonable basis for allocating common expenses.

Basis of Presentation

In the opinion of management, all adjustments necessary to fairly present the consolidated financial position of the Company at December 31, 2011 and 2010 and the results of its operations and cash flows for the years ended December 31, 2011, 2010 and 2009, have been included and are of a normal recurring nature except as otherwise disclosed.

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 accounting principles for certain types of rate-regulated activities, which provide that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment.

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

The following table is a summary of OG&E's regulatory assets and liabilities at:

December 31 *(In millions)*		**2011**		2010
Regulatory Assets				
Current				
Fuel clause under recoveries	**$**	**1.8**	$	1.0
Other (A)		**14.2**		4.9
Total Current Regulatory Assets	**$**	**16.0**	$	5.9
Non-Current				
Benefit obligations regulatory asset	**$**	**359.2**	$	365.5
Income taxes recoverable from customers, net		**54.0**		43.3
Smart Grid		**37.2**		14.2
Deferred storm expenses		**23.8**		28.6
Unamortized loss on reacquired debt		**14.2**		15.3
Deferred Pension expenses		**9.1**		13.5
Other		**10.4**		9.0
Total Non-Current Regulatory Assets	**$**	**507.9**	$	489.4
Regulatory Liabilities				
Current				
Smart Grid rider over collections (B)	**$**	**24.3**	$	10.4
Fuel clause over recoveries		**7.7**		29.9
Other (B)		**13.7**		10.5
Total Current Regulatory Liabilities	**$**	**45.7**	$	50.8
Non-Current				
Accrued removal obligations, net	**$**	**208.2**	$	184.9
Pension tracker		**22.5**		8.2
Total Non-Current Regulatory Liabilities	**$**	**230.7**	$	193.1

(A) Included in Other Current Assets on the Consolidated Balance Sheets.
(B) Included in Other Current Liabilities on the Consolidated Balance Sheets.

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.

The benefit obligations regulatory asset is comprised of expenses recorded which are probable of future recovery and that have not yet been recognized as components of net periodic benefit cost, including net loss, prior service cost and net transition obligation. These expenses were allowed to be recorded as a regulatory asset as OG&E had historically recovered and currently recovers pension and postretirement benefit plan expense in its electric rates and there was no negative evidence that the existing regulatory treatment would change. 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 benefit obligations regulatory asset balance to be reclassified to Accumulated Other Comprehensive Income.

The following table is a summary of the components of the benefit obligations regulatory asset at:

December 31 *(In millions)*	**2011**	2010
Pension Plan and Restoration of Retirement Income Plan:		
Net loss	**$ 266.3**	$ 215.0
Prior service cost	**7.0**	9.7
Postretirement plans:		
Net loss	**144.2**	135.7
Prior service cost	**(60.8)**	—
Net transition obligation	**2.5**	5.1
Total	**$ 359.2**	$ 365.5

The following amounts in the benefit obligations regulatory asset at December 31, 2011 are expected to be recognized as components of net periodic benefit cost in 2012:

(In millions)	
Pension Plan and Restoration of Retirement Income Plan:	
Net loss	**$ 18.8**
Prior service cost	**2.5**
Postretirement plans:	
Net loss	**17.3**
Prior service cost	**(13.7)**
Net transition obligation	**2.5**
Total	**$ 27.4**

Income taxes recoverable from customers, which represents income tax benefits previously used to reduce OG&E's revenues, are treated as regulatory assets and liabilities and are being amortized over the estimated remaining life of the assets to which they relate. These amounts are being recovered in rates as the temporary differences that generated the income tax benefit turn around. The income tax related regulatory assets and liabilities are netted in Income Taxes Recoverable from Customers, Net in the regulatory assets and liabilities table above.

In accordance with the OCC order received by OG&E in July 2010 related to its Smart Grid project, OG&E established a regulatory asset which includes the cost of system-wide deployment of smart grid technology and implementing the smart grid pilot program, the incremental costs for web portal access, education and providing home energy reports and stranded costs associated with OG&E's existing meters. The costs recoverable from Oklahoma customers for system-wide deployment of smart grid technology and implementing the smart grid pilot program are capped at $366.4 million (inclusive of the U.S. Department of Energy grant award amount) subject to an offset for any recovery of those costs from Arkansas customers and are currently being recovered through a rider which will remain in effect until the Smart Grid project costs are included in base rates beginning in 2014. The incremental costs for web portal access, education and home energy reports are capped at $6.9 million and will be recovered in base rates beginning in 2014. The stranded costs associated with OG&E's existing meters which are being replaced by smart meters will accumulate during the Smart Grid deployment and recovery of the stranded costs will be included in future rate cases. OG&E received an order from the APSC in August 2011 related to its Arkansas Smart Grid project. OG&E will recover estimated capital costs of $14 million and associated operation and maintenance costs for deployment of smart grid technology, along with incremental costs for web portal access and education of $0.8 million, through a rider. The rider will become effective when the smart meters are fully deployed in Arkansas, which is expected during the second quarter of 2012, and will remain in effect until new base rates are implemented subsequent to OG&E's next rate case. The APSC also authorized OG&E to record a regulatory asset for stranded costs associated with OG&E's existing meters and to recover the stranded meter regulatory asset in base rates subsequent to OG&E's next rate case.

In accordance with the September 2008 OCC rate order, OG&E was allowed to defer the Oklahoma storm-related operation and maintenance expenses in excess of $2.7 million and will reserve for any Oklahoma storm-related operation and maintenance expenses less than $2.7 million. OG&E will recover the deferred amounts over a five-year period ending in August 2013.

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. These deferred amounts have been recorded as a regulatory asset as OG&E received an order in July 2009 allowing it to begin recovery of $16.8 million of these costs over a four-year period. In accordance with the APSC order received by OG&E in May 2009 in its Arkansas rate case, OG&E was allowed recovery of its 2006 and 2007 pension settlement costs. During the second quarter of 2009, OG&E reduced its pension expense and recorded a regulatory asset for $3.2 million, which is being amortized over a 10-year period, as allowed in the Arkansas rate order. Both the Oklahoma and Arkansas pension plan expenses are reflected in Deferred Pension expenses asset in the regulatory assets and liabilities table above. Also, in accordance with the OCC order received by OG&E in August 2009 in its Oklahoma rate case, OG&E was allowed to recover a certain amount of pension plan expenses. In accordance with the OCC order received by OG&E in September 2011 in its pension tracker modification filing, OG&E was allowed to include postretirement medical expense in its pension tracker. At December 31, 2011, OG&E had $22.5 million of expenses under this level, which have been recorded as Pension tracker regulatory liability in the regulatory assets and liabilities table above.

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 adjusted, as appropriate. If the Company were required to discontinue the application of accounting principles for certain types of rate-regulated activities for some or all of its operations, it could result in writing off the related regulatory assets, which could have significant financial effects.

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 for all Company segments includes the valuation of Pension Plan assumptions, impairment estimates of long-lived assets (including intangible assets) and goodwill, income taxes, contingency reserves, asset retirement obligations, fair value and cash flow hedges and the allowance for uncollectible accounts receivable. For the electric utility segment, the most significant judgment is also exercised in the valuation of regulatory assets and liabilities and unbilled revenues. For the natural gas transportation and storage, gathering and processing and marketing segments, the most significant judgment is also exercised in the valuation of operating revenues, natural gas purchases, purchase and sale contracts, assets and depreciable lives of property, plant and equipment and amortization methodologies related to intangible assets.

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. Beginning in August 2009 and going forward, there was a change in the provision calculation as a result of the Oklahoma rate case whereby the portion of the uncollectible provision related to fuel is being recovered through the fuel adjustment clause. Due to the extremely hot weather in OG&E's service territory in 2011, OG&E recorded an additional amount of uncollectible expense anticipating higher customer defaults. 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 Enogex believes the collection of specific amounts owed is unlikely to occur. The allowance for uncollectible accounts receivable was $3.8 million and $1.9 million at December 31, 2011 and 2010, respectively.

For OG&E, new business customers are required to provide a security deposit in the form of cash, bond or irrevocable letter of credit that is refunded when the account is closed. New residential customers, whose outside credit scores indicate risk, are required to provide a security deposit that is refunded based on customer protection rules defined by the OCC and the APSC. The payment behavior of all existing customers is continuously monitored and, if the payment behavior indicates sufficient risk within the meaning of the applicable utility regulation, customers will be required to provide a security deposit.

For Enogex, credit risk is the risk of financial loss to Enogex if counterparties fail to perform their contractual obligations. Enogex maintains credit policies with regard to its counterparties that management believes minimize overall credit risk. These policies include the evaluation of a potential counterparty's financial position (including credit rating, if available), collateral requirements under certain circumstances, the use of standardized agreements which provide for the netting of cash flows associated with a single counterparty and the monitoring of 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. OG&E uses the weighted-average cost method of accounting for inventory that is physically added to or withdrawn from storage or stockpiles. The amount of fuel inventory was $76.9 million and $134.9 million at December 31, 2011 and 2010, respectively.

Enogex

Natural gas inventory is held by Enogex, through its transportation and storage business to provide operational support for its pipeline deliveries and through its marketing business to manage its leased storage capacity. In an effort to mitigate market price exposures, Enogex may enter into contracts or hedging instruments to protect the cash flows associated with its inventory. All natural gas inventory held by Enogex is valued using moving average cost and is recorded at the lower of cost or market. As part of its recurring marketing activity, OER injects and withdraws natural gas into and out of inventory under the terms of its storage capacity contracts. During the years ended December 31, 2011, 2010 and 2009, Enogex recorded write-downs to market value related to natural gas storage inventory of $4.8 million, $0.3 million and $6.1 million, respectively. The amount of Enogex's natural gas inventory was $23.7 million and $23.9 million at December 31, 2011 and 2010, respectively. The cost of gas associated with sales of natural gas storage inventory is presented 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 depending on contractual terms. 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 is 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. 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 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 net of any salvage proceeds 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 table below presents OG&E's ownership interest in the jointly-owned McClain Plant and the jointly-owned Redbud Plant, and, as disclosed below, only OG&E's ownership interest is reflected in the property, plant and equipment and accumulated depreciation balances in these tables. The owners of the remaining interests in the McClain Plant and the Redbud Plant 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 Plant such as fuel, maintenance expense and other operating expenses are included in the applicable financial statement captions in the Consolidated Statement of Income.

December 31, 2011 *(In millions)*	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
McClain Plant	**77%**	**$ 207.2**	**$ 73.7**	**$ 133.5**
Redbud Plant	**51%**	**$ 461.1 (A)**	**$ 54.3 (B)**	**$ 406.8**

(A) This amount includes a plant acquisition adjustment of $148.3 million.
(B) This amount includes accumulated amortization of the plant acquisition adjustment of $17.9 million.

Enogex

All property, plant and equipment is 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 net of any salvage proceeds 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.

On December 8, 2010, a fire occurred at Enogex's Cox City natural gas processing plant destroying major components of one of the four processing trains, representing 120 MMcf/d of the total 180 MMcf/d of capacity, at that facility. Gas volumes normally processed at the Cox City plant were diverted to other facilities or bypassed around Enogex's system to accommodate production and all of the impacted gathered volumes were back online in December 2010. The damaged train was replaced and the facility was returned to full service in September 2011. The total cost necessary to return the facility back to full service was $29.6 million. While Enogex believes that the costs in excess of the $10 million deductible should be reimbursed by insurance, the matter is currently being negotiated with the insurance company and Enogex cannot predict the precise outcome of these negotiations or the timing associated with the recovery. In the fourth quarter of 2011, Enogex received a partial insurance reimbursement of $7.4 million and recognized a gain of $3.0 million on insurance proceeds. Enogex expects to receive additional reimbursement of portions of the costs in 2012. Enogex will recognize insurance recoveries in earnings as the insurance claims are resolved.

OGE Energy Consolidated

The Company's property, plant and equipment and related accumulated depreciation are divided into the following major classes at:

December 31, 2011 *(In millions)*	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
OGE Energy (holding company)			
Property, plant and equipment	**$ 124.6**	**$ 90.6**	**$ 34.0**
OGE Energy property, plant and equipment	**124.6**	**90.6**	**34.0**
OG&E			
Distribution assets	**2,981.3**	**920.3**	**2,061.0**
Electric generation assets	**3,360.6**	**1,215.8**	**2,144.8**
Transmission assets	**1,464.2**	**339.6**	**1,124.6**
Intangible plant	**43.2**	**20.3**	**22.9**
Other property and equipment	**293.9**	**96.3**	**197.6**
OG&E property, plant and equipment	**8,143.2**	**2,592.3**	**5,550.9**
Enogex			
Transportation and storage assets	**956.9**	**271.0**	**685.9**
Gathering and processing assets	**1,580.1**	**381.0**	**1,199.1**
Marketing assets	**10.1**	**6.0**	**4.1**
Enogex property, plant and equipment	**2,547.1**	**658.0**	**1,889.1**
Total property, plant and equipment	**$ 10,814.9**	**$ 3,340.9**	**$ 7,474.0**

December 31, 2010 (In millio*ns)*	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
OGE Energy (holding company)			
Property, plant and equipment	$ 111.1	$ 77.5	$ 33.6
OGE Energy property, plant and equipment	111.1	77.5	33.6
OG&E			
Distribution assets	2,833.4	897.4	1,936.0
Electric generation assets	3,047.1	1,164.6	1,882.5
Transmission assets	1,221.3	325.6	895.7
Intangible plant	26.5	20.7	5.8
Other property and equipment	243.4	86.1	157.3
OG&E property, plant and equipment	7,371.7	2,494.4	4,877.3
Enogex			
Transportation and storage assets	924.7	250.0	674.7
Gathering and processing assets	1,230.8	354.6	876.2
Marketing assets	9.7	7.1	2.6
Enogex property, plant and equipment	2,165.2	611.7	1,553.5
Total property, plant and equipment	$ 9,648.0	$ 3,183.6	$ 6,464.4

Depreciation and Amortization

OG&E

The provision for depreciation, which was 2.9 percent and 3.0 percent, respectively, of the average depreciable utility plant for 2011 and 2010, 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 2012, the provision for depreciation is projected to be 2.9 percent of the average depreciable utility plant. Amortization of intangible assets is computed using the straight-line method. Of the remaining amortizable intangible plant balance at December 31, 2011, 48.3 percent will be amortized over three years with 51.7 percent of the remaining amortizable intangible plant balance at December 31, 2011 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 of the acquired asset. Plant acquisition adjustments include $148.3 million for the Redbud Plant, which are being amortized over a 27-year life and $3.3 million for certain substation facilities in OG&E's service territory, which are being amortized over a 26 to 59-year period.

Enogex

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

The computation of depreciation expense requires judgment regarding the estimated useful lives and salvage value of assets at the time the assets are placed in service. As circumstances warrant, useful lives are adjusted when changes in planned use, changes in estimated production lives of affiliated natural gas basins or other factors indicate that a different life would be more appropriate. Such changes could materially impact future depreciation expense. Changes in useful lives that do not result in the impairment of an asset are recognized prospectively. The computation of amortization expense on intangible assets requires judgment regarding the amortization method used. The intangible asset should be amortized over its useful life using a method of amortization that reflects the pattern in which the economic benefits of the intangible asset are consumed.

Asset Retirement Obligations

The Company has previously recorded asset retirement obligations that are being amortized over their respective lives ranging from 20 to 99 years. In the fourth quarter of 2011, OG&E recorded an asset retirement obligation for $13.0 million related to its Crossroads wind farm. Beginning December 1, 2011, OG&E began to amortize the value of the related asset retirement obligation asset over the estimated remaining life of 50 years. The Company also has certain asset retirement obligations 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 Long-Lived Assets (Including Intangible Assets) and Goodwill

The Company assesses its long-lived assets, including intangible assets with finite useful lives, for impairment when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset's carrying amount. Estimates of future cash flows used to test the recoverability of long-lived assets and intangible assets 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. 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. In 2011, the Company recorded a pre-tax impairment loss of $5.0 million, of which $2.5 million was the noncontrolling interest portion (see Note 5), related to the Atoka processing plant. The Company recorded no other material impairments in 2011, 2010 and 2009.

As a result of the gas gathering acquisitions on November 1, 2011 discussed in Note 3, Enogex recorded goodwill of $39.4 million and intangible assets of $136.3 million. Enogex will assess its goodwill for impairment at least annually as of October 1 and will assess the intangible assets for impairment as discussed above.

Allowance for Funds Used During Construction

For OG&E, allowance for funds used during construction is calculated according to the FERC pronouncements for the imputed cost of equity and borrowed funds. Allowance for funds used during construction, a non-cash item, is reflected as a reduction to interest expense in the Consolidated Statements of Income and as an increase to Construction Work in Progress in the Consolidated Balance Sheets. Allowance for funds used during construction rates, compounded semi-annually, were 8.71 percent, 8.89 percent and 7.99 percent for the years ended December 31, 2011, 2010 and 2009, respectively. The decrease in the allowance for funds used during construction rates in 2011 was primarily due to the issuance of long-term debt which changed the cost of capital weighting to shift towards debt which has a lower effective rate than equity.

Collection of Sales Tax

In the course of its operations, OG&E collects sales tax from its customers. OG&E records a current liability for 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. 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. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

SPP Purchases and Sales

OG&E participates in the 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' 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, storage and marketing 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. Enogex's key natural gas producer customers in 2011 included Chesapeake Energy Marketing Inc., Apache Corporation, Devon Energy Production Company, L.P., BP America Production Company and Kaiser Francis Oil Co. In 2011, these five customers accounted for 19.9 percent, 15.0 percent, 12.5 percent, 4.1 percent and 3.9 percent, respectively, of Enogex's gathering and processing volumes. In 2011, Enogex's top 10 natural gas producer customers accounted for 69.4 percent of Enogex's gathering and processing volumes.

Enogex recognizes revenue from natural gas gathering, processing, transportation, storage and marketing services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold. Enogex depends on third-party facilities to transport and fractionate NGLs that it delivers to the third party at the tailgates of its processing plants. Additionally, the third party purchases 50 percent of the NGLs delivered to its system, which accounted for $285.4 million (38.8 percent, $279.8 million (46.0 percent) and $170.0 million (49.5 percent), respectively, of Enogex's total NGLs sales for the years ended December 31, 2011, 2010 and 2009. If this third-party's pipeline or other facilities become partially or fully unavailable, Enogex's revenues and cash flows could be adversely affected.

Enogex records deferred revenue when it receives consideration from a third party before achieving certain criteria that must be met for revenue to be recognized in accordance with GAAP.

Enogex, through OER, engages in energy marketing, trading, risk management and hedging activities related to the purchase and sale of natural gas as well as hedging activity related to the sale of natural gas and NGLs on behalf of the Company. 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. OER's transactions that qualify as derivatives are reflected at fair value with the resulting unrealized gains and losses recorded as PRM 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. Contracts resulting in delivery of a commodity 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.

Estimates for gas purchases are based on estimated 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.

Normal purchases and normal sales contracts are not recorded in PRM 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 treatment to: (i) commodity contracts for the purchase and sale of natural gas used in or produced by Enogex's operations and (ii) commodity contracts for the sale of NGLs produced by Enogex's gathering and processing business.

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.

Income Taxes

The Company files consolidated income tax returns in the U.S. Federal jurisdiction and various state jurisdictions. 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 uses the asset and liability method of accounting for income taxes. Under this method, a deferred tax asset or liability is recognized for the estimated future tax effects attributable to temporary differences between the financial statement basis and the tax basis of assets and liabilities as well as tax credit carry forwards and net operating loss carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period of the change. The Company recognizes interest related to unrecognized tax benefits in interest expense and recognizes penalties in other expense.

Accrued Vacation

The Company accrues vacation pay monthly by establishing a liability for vacation earned. Vacation may be taken as earned and is charged against the liability. At the end of each year, the liability represents the amount of vacation earned, but not taken.

Accumulated Other Comprehensive Income (Loss)

The following table summarizes the components of accumulated other comprehensive loss at December 31, 2011 and 2010 attributable to OGE Energy. At both December 31, 2011 and 2010, there was no accumulated other comprehensive loss related to Enogex's noncontrolling interest in Atoka.

December 31 *(In millions)*	**2011**	2010
Pension Plan and Restoration of Retirement Income Plan:		
Net loss	**$ (42.1)**	$ (31.1)
Prior service cost	**(0.1)**	(0.5)
Postretirement plans:		
Net loss	**(15.4)**	(13.6)
Prior service cost	**9.0**	—
Net transition obligation	**(0.1)**	(0.3)
Deferred commodity contracts hedging losses	**3.3**	(19.5)
Deferred interest rate swaps hedging losses	**(0.7)**	(1.0)
Total accumulated other comprehensive loss	**(46.1)**	(66.0)
Less: Accumulated other comprehensive loss attributable to noncontrolling interests	**(5.5)**	(5.8)
Accumulated other comprehensive loss, net of tax	**$ (40.6)**	$ (60.2)

Of the deferred hedging losses at December 31, 2011, $4.9 million are expected to be recognized into earnings during 2012.

Pension Plan, Restoration of Retirement Income Plan and Postretirement Plans

The amounts in accumulated other comprehensive loss at December 31, 2011 that are expected to be recognized as components of net periodic benefit cost in 2012 are as follows:

(In millions)	
Pension Plan and Restoration of Retirement Income Plan:	
Net loss	**$ 2.7**
Prior service cost	**0.3**
Postretirement plans:	
Net loss	**1.9**
Prior service cost	**(1.8)**
Net transition obligation	**0.1**
Total, net of tax	**$ 3.2**

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. The Company has less than $0.1 million in accrued environmental liabilities at both December 31, 2011 and 2010.

Reclassifications

Certain prior year amounts have been reclassified on the Consolidated Statements of Income for impairment of assets and on the Consolidated Balance Sheet for intangible assets to conform to the 2011 presentation.

2. Accounting Pronouncements

In December 2011, the Financial Accounting Standards Board issued "Balance Sheet: Disclosures about Offsetting Assets and Liabilities." The new standard requires entities to disclose information about financial instruments and derivative instruments that are either offset on the balance sheet or are subject to a master netting arrangement, including providing both gross information and net information for recognized assets and liabilities, the net amounts presented on an entity's balance sheet and a description of the rights of setoff associated with these assets and liabilities. The new standard is applicable for all entities that have financial instruments and derivative instruments shown using a net presentation on an entity's balance sheet or are subject to a master netting arrangement. The new standard is effective for interim and annual reporting periods for fiscal years beginning on or after January 1, 2013 and should be applied retrospectively for all periods presented. The Company plans to adopt this new standard effective January 1, 2013 and will provide any additional disclosures necessary to comply with the new standard.

In December 2011, the Financial Accounting Standards Board issued "Comprehensive Income: Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income in Accounting Standards Update No. 2011-05." The new standard defers the effective date of changes from previous accounting guidance that related to the presentation of reclassification adjustments. The new standard is applicable for all entities that have other comprehensive income. The new standard is effective for interim and annual reporting periods for fiscal years beginning after December 15, 2011. The Company adopted this new standard effective January 1, 2012.

3. Business Combination

On September 23, 2011, Enogex entered into the following agreements: an agreement with Cordillera, Oxbow and West Canadian Midstream LLC pursuant to which Enogex agreed to acquire 100 percent of the membership interest in Roger Mills Gas Gathering, LLC, an Oklahoma limited liability company that owns an approximately 60-mile natural gas gathering system located in Roger Mills County and Ellis County, Oklahoma; an agreement with Cordillera and Oxbow pursuant to which Enogex agreed to acquire an approximately 30-mile natural gas gathering system located in Roger Mills County, Oklahoma; and agreements with Cordillera and other producers pursuant to which such producers agreed to provide Enogex with long-term acreage dedication in the area served by the gathering systems encompassing approximately 100,000 net acres. The gathering systems are located in the Granite Wash area. The aggregate purchase price for these transactions was $200.4 million which was paid in cash primarily from contributions from OGE Energy and the ArcLight group (as discussed in Note 4) as well as cash generated from operations and bank borrowings. The transactions closed on November 1, 2011.

The acquisition described above was accounted for as a business combination. The purchase price shown below is preliminary and has been allocated to the identifiable assets acquired and liabilities assumed based on the estimated fair values at the acquisition date using a third-party valuation expert. Any amount not allocated to identifiable assets and liabilities was allocated to goodwill. These allocations may change in subsequent financial statements. Enogex is currently evaluating the preliminary purchase price allocation, which will be adjusted as additional information relative to the fair value of assets and liabilities becomes available. Enogex expects the purchase price allocations to be completed by the end of the first quarter of 2012. The following table summarizes the preliminary purchase price allocation for this acquisition.

(In millions)		
Current assets	$	5.4
Net property, plant and equipment		24.3
Intangible assets		136.3
Goodwill		39.4
Current liabilities assumed		(5.0)
Total	$	200.4

The goodwill recognized from this acquisition primarily related to the benefits associated with combining the acquired assets with Enogex's existing assets and operations. Enogex believes that the transactions will provide Enogex with key new opportunities in the Granite Wash area. All of the goodwill is deductible for tax purposes. The goodwill has been recorded in the Gathering and Processing segment. At December 31, 2011, there were no changes in the recognized amount of goodwill resulting from this acquisition.

Intangible assets consist of an identifiable customer contracts and relationships. The acquired intangible assets will be amortized on a straight-line basis over the estimated remaining useful life of 15 years. The net amount of intangible assets and related accumulated amortization was $134.8 million and $1.5 million, respectively, at December 31, 2011.

4. Noncontrolling Interest Owner

In 2011, OGE Energy and the ArcLight group made contributions to Enogex Holdings of $70.9 million and $214.6 million, respectively, to fund a portion of Enogex LLC's 2011 capital requirements. Also, on February 1, 2011, OGE Energy sold a 0.1 percent membership interest in Enogex Holdings to the ArcLight group for $1.9 million. The following table summarizes changes in OGE Holdings' and the ArcLight group's membership interest in Enogex Holdings in 2011.

(In millions)	OGE Holdings	ArcLight group	Total
Balance at December 31, 2010 (units)	90.1	9.9	100.0
Ownership percentage at December 31, 2010	90.1%	9.9%	100.0%
Sale of 100,000 units of Enogex Holdings (A)	(0.1)	0.1	—
Issuance of 4,303,007 units of Enogex Holdings (B)	0.4	3.9	4.3
Issuance of 5,405,405 units of Enogex Holdings (C)	0.5	4.9	5.4
Issuance of 5,725,190 units of Enogex Holdings (D)	2.9	2.8	5.7
Balance at December 31, 2011 (units)	93.8	21.6	115.4
Ownership percentage at December 31, 2011	81.3%	18.7%	100.0%

(A) On February 1, 2011, OGE Energy sold a 0.1 percent membership interest in Enogex Holdings to the ArcLight group for $1.9 million.
(B) On February 1, 2011, OGE Energy and the ArcLight group made contributions of $8.0 million and $71.6 million, respectively, to fund a portion of Enogex LLC's 2011 capital requirements.
(C) On October 3, 2011, OGE Energy and the ArcLight group made contributions of $10.0 million and $90.0 million, respectively, to fund a portion of Enogex LLC's 2011 capital requirements.
(D) On November 1, 2011, OGE Energy and the ArcLight group made contributions of $52.9 million and $53.0 million, respectively, to fund Enogex's gas gathering acquisitions as discussed in Note 3.

The following table summarizes changes in OGE Energy's equity which represents changes in additional paid-in capital for unrecognized gains from the sale and issuance of equity interests in Enogex Holdings to the ArcLight group in 2011.

(In millions)	
Net income attributable to OGE Energy	**$ 342.9**
Transfers to the noncontrolling interest	
Increase in paid-in capital for sale of 100,000 units of Enogex Holdings (net of tax of $0.3 million)	**0.5**
Increase in paid-in capital for issuance of 4,303,007 units of Enogex Holdings (net of tax of $10.9 million)	**17.3**
Increase in paid-in capital for issuance of 5,405,405 units of Enogex Holdings (net of tax of $12.3 million)	**19.5**
Increase in paid-in capital for issuance of 5,725,190 units of Enogex Holdings (net of tax of $5.2 million)	**8.2**
Net transfers to the noncontrolling interest	**45.5**
Total of net income attributable to OGE Energy and transfers from noncontrolling interest	**$ 388.4**

The following table summarizes the quarterly distributions by Enogex Holdings to its partners in 2011.

(In millions)	OGE Holdings Portion	ArcLight group's Portion	Total Distribution
First quarter 2011	$ 7.5	$ 0.8	$ 8.3
Second quarter 2011	34.3	5.3	39.6
Third quarter 2011	43.4	6.6	50.0
Fourth quarter 2011	30.4	4.7	35.1
Total	$ 115.6	$ 17.4	$ 133.0

5. Impairment of Assets

Atoka operated a 20 MMcf/d refrigeration processing plant which processed gas gathered in the Atoka area. The processing plant was leased on a month-to-month basis. In August 2011, management made a decision to use third-party processing exclusively for gathered volumes dedicated to Atoka and, therefore, to take the processing plant out of service and return it to the lessor in accordance with the rental agreement. As a result, in August 2011 Enogex recorded a pre-tax impairment loss of $5.0 million in the Gathering and Processing segment associated with the cost it had capitalized in connection with the installation of the leased plant as it will not be able to recover the remaining value of the assets through future cash flows. The Atoka plant assets were measured at fair value on a nonrecurring basis and are considered level 3 in the fair value hierarchy (see Note 6). The noncontrolling interest portion of the pre-tax impairment loss was $2.5 million which is included in Net Income Attributable to Noncontrolling Interests in the Company's Consolidated Statement of Income.

6. Fair Value Measurements

The classification of the Company's fair value measurements requires judgment regarding the degree to which market data are observable or corroborated by observable market data. GAAP establishes a fair value hierarchy that prioritizes the inputs used to measure fair value based on observable and unobservable data. The hierarchy categorizes the inputs into three levels, with the highest priority given to quoted prices in active markets for identical unrestricted assets or liabilities (Level 1) and the lowest priority given to unobservable inputs (Level 3). Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The three levels defined in the fair value hierarchy and examples of each are as follows:

Level 1 inputs are quoted prices in active markets for identical unrestricted assets or liabilities that are accessible at the measurement date. Instruments classified as Level 1 include natural gas futures, swaps and option transactions for contracts traded on the NYMEX and settled through a NYMEX clearing broker.

Level 2 inputs are inputs other than quoted prices in active markets included within Level 1 that are either directly or indirectly observable at the reporting date for the asset or liability for substantially the full term of the asset or liability. Level 2 inputs include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active. Instruments classified as Level 2 include over-the-counter NYMEX natural gas swaps, natural gas basis swaps and natural gas purchase and sales transactions in markets such that the pricing is closely related to the NYMEX pricing.

Level 3 inputs are prices or valuation techniques for the asset or liability that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity). Unobservable inputs 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). Instruments classified as Level 3 include the revaluation of the Atoka plant assets (see Note 5).

The Company utilizes the market approach in determining the fair value of its derivative positions by using either NYMEX published market prices, independent broker pricing data or broker/dealer valuations. 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. In certain less liquid markets or for longer-term contracts, forward prices are not as readily available. In these circumstances, contracts are valued using internally developed methodologies that consider historical relationships among various quoted prices in active markets that result in management's best estimate of fair value. These contracts are classified as 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 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.

Contracts with Master Netting Arrangements

Fair value amounts recognized for forward, interest rate 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, 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 derivative contracts under master netting agreements using a net fair value presentation.

The following tables summarize the Company's assets and liabilities that are measured at fair value on a recurring basis at December 31, 2011 and 2010 as well as reconcile the Company's commodity contracts fair value to PRM Assets and Liabilities on the Company's Consolidated Balance Sheets at December 31, 2011 and 2010. There were no Level 3 investments held at December 31, 2011.

December 31, 2011				
(In millions)	Commodity Contracts		Gas Imbalances (A)	
	Assets	Liabilities	Assets	Liabilities (B)
Quoted market prices in active market for identical assets (Level 1)	**$ 57.1**	**$ 52.3**	**$ —**	**$ —**
Significant other observable inputs (Level 2)	**4.2**	**1.2**	**1.8**	**7.8**
Total fair value	**61.3**	**53.5**	**1.8**	**7.8**
Netting adjustments	**(57.5)**	**(53.0)**	**—**	**—**
Total	**$ 3.8**	**$ 0.5**	**$ 1.8**	**$ 7.8**

December 31, 2010				
(In millions)	Commodity Contracts		Gas Imbalances (A)	
	Assets	Liabilities	Assets	Liabilities (B)
Quoted market prices in active market for identical assets (Level 1)	$ 20.6	$ 20.2	$ —	$ —
Significant other observable inputs (Level 2)	2.7	30.7	2.5	2.8
Significant unobservable inputs (Level 3)	13.3	—	—	—
Total fair value	36.6	50.9	2.5	2.8
Netting adjustments	(34.4)	(34.1)	—	—
Total	$ 2.2	$ 16.8	$ 2.5	$ 2.8

(A) The Company uses the market approach to fair value its gas imbalance assets and liabilities, using an average of the Inside FERC Gas Market Report for Panhandle Eastern Pipe Line Co. (Texas, Oklahoma Mainline), ONEOK (Oklahoma) and ANR Pipeline (Oklahoma) indices.

(B) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of $2.0 million and $3.9 million at December 31, 2011 and 2010, respectively, 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 following table summarizes the Company's assets and liabilities that are measured at fair value on a recurring basis using significant unobservable inputs (Level 3).

	Commodity Contracts			
	Assets		Liabilities	
(In millions)	**2011**	2010	**2011**	2010
Balance at January 1	**$ 13.3**	$ 49.0	**$ —**	$ 14.7
Total gains or losses				
Included in other comprehensive income	**(5.4)**	(10.0)	**—**	—
Settlements	**(7.9)**	(25.7)	**—**	(14.7)
Balance at December 31	**$ —**	$ 13.3	**$ —**	$ —

In the fourth quarter of 2011, OG&E recorded an asset retirement obligation for $13.0 million related to its Crossroads wind farm, which is measured at fair value on a nonrecurring basis and is considered level 3 in the fair value hierarchy. The inputs used in the valuation of the asset retirement obligation include the term of the Crossroads lease agreement, the average inflation rate, market risk premium and the credit-adjusted risk free interest rate. The term of the asset retirement obligation of 50 years was determined by the Crossroads lease agreement which states that OG&E will remove the wind turbines and related facilities at the time the lease expires. The inflation rate is calculated by using a 20-year average of the Consumer Price Index. The market risk premium is based on historical market returns relative to the U.S. Treasury rate. The credit-adjusted risk free interest rate is estimated from recent yields of OG&E's outstanding debt.

The following table summarizes the fair value and carrying amount of the Company's financial instruments, including derivative contracts related to the Company's PRM activities, at:

December 31 *(In millions)*	**2011**		2010	
	Carrying Amount	**Fair Value**	Carrying Amount	Fair Value
Price Risk Management Assets				
Energy Derivative Contracts	**$ 3.8**	**$ 3.8**	$ 2.2	$ 2.2
Price Risk Management Liabilities				
Energy Derivative Contracts	**$ 0.5**	**$ 0.5**	$ 16.8	$ 16.8
Long-Term Debt				
OG&E Senior Notes	**$ 1,903.8**	**$ 2,383.8**	$ 1,655.0	$ 1,831.5
OGE Energy Senior Notes	**99.8**	**108.5**	99.7	106.4
OG&E Industrial Authority Bonds	**135.4**	**135.4**	135.4	135.4
Enogex LLC Senior Notes	**448.1**	**497.9**	447.8	480.7
Enogex LLC Revolving Credit Agreement	**150.0**	**150.0**	25.0	25.0

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 energy derivative 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 estimates of current rates available for similar issues with similar maturities.

7. Derivative Instruments and Hedging Activities

The Company is exposed to certain risks relating to its ongoing business operations. The primary risks managed using derivatives instruments are commodity price risk and interest rate risk. The Company is also exposed to credit risk in its business operations.

Commodity Price Risk

The Company primarily uses forward physical contracts, commodity price swap contracts and commodity price option features to manage the Company's commodity price risk exposures. Commodity derivative instruments used by the Company are as follows:

- NGLs put options and NGLs swaps are used to manage Enogex's NGLs exposure associated with its processing agreements;
- natural gas swaps are used to manage Enogex's keep-whole natural gas exposure associated with its processing operations and Enogex's natural gas exposure associated with operating its gathering, transportation and storage assets;
- natural gas futures and swaps and natural gas commodity purchases and sales are used to manage OER's natural gas exposure associated with its storage and transportation contracts; and
- natural gas futures and swaps, natural gas options and natural gas commodity purchases and sales are used to manage OER's marketing and trading activities.

Normal purchases and normal sales contracts are not recorded in PRM 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 treatment to: (i) commodity contracts for the purchase and sale of natural gas used in or produced by Enogex's operations, (ii) commodity contracts for the sale of NGLs produced by Enogex's gathering and processing business, (iii) electric power contracts by OG&E and (iv) fuel procurement by OG&E.

The Company recognizes its non-exchange traded derivative instruments as PRM 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.

Interest Rate Risk

The Company's exposure to changes in interest rates primarily relates to short-term variable-rate debt and commercial paper. The Company manages its interest rate exposure by monitoring and limiting the effects of market changes in interest rates. The Company utilizes interest rate derivatives to alter interest rate exposure in an attempt to reduce the effects of these changes. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Credit Risk

The Company is exposed to certain credit risks relating to its ongoing business operations. 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.

Cash Flow Hedges

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 or hedge components excluded from the assessment of effectiveness is recognized currently in earnings. The Company measures the ineffectiveness of commodity cash flow hedges using the change in fair value method whereby 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. Forecasted transactions, which are 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.

The Company designates as cash flow hedges derivatives used to manage commodity price risk exposure for Enogex's NGLs volumes and corresponding keep-whole natural gas resulting from its natural gas processing contracts (processing hedges) and natural gas positions resulting from its natural gas gathering and processing, pipeline and storage operations (operational gas hedges). The Company also designates as cash flow hedges certain derivatives used to manage natural gas commodity exposure for certain natural gas storage inventory positions. Enogex's cash flow hedges at December 31, 2011 mature by the end of the first quarter of 2012.

Fair Value Hedges

For derivative instruments that are designated and qualify as a fair value hedge, the gain or loss on the derivative as well as the offsetting loss or gain on the hedged item attributable to the hedge risk are recognized currently in earnings. The Company includes the gain or loss on the hedged items in Operating Revenues as the offsetting loss or gain on the related hedging derivative.

At December 31, 2011 and 2010, the Company had no derivative instruments that were designated as fair value hedges.

Derivatives Not Designated As Hedging Instruments

Derivative instruments not designated as hedging instruments are utilized in OER's asset management, marketing and trading activities. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized currently in earnings.

Quantitative Disclosures Related to Derivative Instruments

At December 31, 2011, the Company had the following derivative instruments that were designated as cash flow hedges.

(In millions)	2011 Gross Notional Volume (A)
Enogex marketing hedges	
Natural gas sales	3.2

(A) Natural gas in MMBtu's.

At December 31, 2011, the Company had the following derivative instruments that were not designated as hedging instruments.

(In millions)	Gross Notional Volume (A)	
	Purchases	Sales
Natural gas (B)		
Physical (C)(D)	14.3	51.8
Fixed Swaps/Futures	57.9	58.2
Options	17.6	12.8
Basis Swaps	8.2	7.5

(A) Natural gas in MMBtu's.
(B) 88.0 percent of the natural gas contracts have durations of one year or less, 5.5 percent have durations of more than one year and less than two years and 6.5 percent have durations of more than two years.
(C) Of the natural gas physical purchases and sales volumes not designated as hedges, the majority are priced based on a monthly or daily index and the fair value is subject to little or no market price risk.
(D) Natural gas physical sales volumes exceed natural gas physical purchase volumes due to the marketing of natural gas volumes purchased via Enogex's processing contracts, which are not derivative instruments and are excluded from the table above.

Balance Sheet Presentation Related to Derivative Instruments

The fair value of the derivative instruments that are presented in the Company's Consolidated Balance Sheet at December 31, 2011 are as follows:

		Fair Value	
Instrument	**Balance Sheet Location**	**Assets**	**Liabilities**
		(In millions)	
Derivatives Designated as Hedging Instruments			
Natural Gas			
Financial Futures/Swaps	Other Current Assets	$ **5.2**	$ **0.3**
Total		$ **5.2**	$ **0.3**
Derivatives Not Designated as Hedging Instruments			
Natural Gas			
Financial Futures/Swaps	Current PRM	$ **0.4**	$ **—**
	Other Current Assets	**49.9**	**49.9**
Physical Purchases/Sales	Current PRM	**3.1**	**0.4**
	Non-Current PRM	**0.3**	**0.1**
Financial Options	Other Current Assets	**2.4**	**2.8**
Total		$ **56.1**	$ **53.2**
Total Gross Derivatives (A)		$ **61.3**	$ **53.5**

(A) See Note 6 for a reconciliation of the Company's total derivatives fair value to the Company's Consolidated Balance Sheet at December 31, 2011.

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The fair value of the derivative instruments that are presented in the Company's Consolidated Balance Sheet at December 31, 2010 are as follows:

Instrument	Balance Sheet Location	Fair Value Assets	Fair Value Liabilities
		(In millions)	
Derivatives Designated as Hedging Instruments			
NGLs			
Financial Options	Current PRM	$ 13.3	$ —
Natural Gas			
Financial Futures/Swaps	Current PRM	—	28.8
	Other Current Assets	0.6	0.3
Total		$ 13.9	$ 29.1
Derivatives Not Designated as Hedging Instruments			
Natural Gas			
Financial Futures/Swaps	Current PRM	$ —	$ 0.1
	Other Current Assets	20.0	19.8
Physical Purchases/Sales	Current PRM	1.4	1.2
	Non-Current PRM	0.8	—
Financial Options	Other Current Assets	0.5	0.7
Total		$ 22.7	$ 21.8
Total Gross Derivatives (A)		$ 36.6	$ 50.9

(A) See Note 6 for a reconciliation of the Company's total derivatives fair value to the Company's Consolidated Balance Sheet at December 31, 2010.

Income Statement Presentation Related to Derivative Instruments

The following tables present the effect of derivative instruments on the Company's Consolidated Statement of Income in 2011.

Derivatives in Cash Flow Hedging Relationships

(In millions)	Amount Recognized in Other Comprehensive Income (A)	Amount Reclassified from Accumulated Other Comprehensive Income into Income	Amount Recognized in Income
NGLs Financial Options	**$ (8.4)**	**$ (9.8)**	**$ —**
Natural Gas Financial Futures/Swaps	**2.9**	**(30.4)**	**—**
Total	**$ (5.5)**	**$ (40.2)**	**$ —**

(A) The estimated net amount of gains or losses included in Accumulated Other Comprehensive Income at December 31, 2011 that is expected to be reclassified into income within the next 12 months is a loss of $4.9 million.

Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income
Natural Gas Physical Purchases/Sales	**$ (10.0)**
Natural Gas Financial Futures/Swaps	**0.4**
Total	**$ (9.6)**

The following tables present the effect of derivative instruments on the Company's Consolidated Statement of Income in 2010.

Derivatives in Cash Flow Hedging Relationships

(In millions)	Amount Recognized in Other Comprehensive Income	Amount Reclassified from Accumulated Other Comprehensive Income into Income	Amount Recognized in Income
NGLs Financial Options	$ (9.7)	$ 1.2	$ —
NGLs Financial Futures/Swaps	1.7	(3.7)	—
Natural Gas Financial Futures/Swaps	(14.9)	(25.9)	0.2
Total	$ (22.9)	$ (28.4)	$ 0.2

Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income
Natural Gas Physical Purchases/Sales	$ (11.7)
Natural Gas Financial Futures/Swaps	3.2
Total	$ (8.5)

The following tables present the effect of derivative instruments on the Company's Consolidated Statement of Income in 2009.

Derivatives in Cash Flow Hedging Relationships

(In millions)	Amount Recognized in Other Comprehensive Income	Amount Reclassified from Accumulated Other Comprehensive Income into Income	Amount Recognized in Income
NGLs Financial Options	$ (56.4)	$ 1.7	$ —
NGLs Financial Futures/Swaps	(33.7)	12.6	—
Natural Gas Financial Futures/Swaps	(19.8)	(26.5)	(0.2)
Total	$ (109.9)	$ (12.2)	$ (0.2)

Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income
Natural Gas Physical Purchases/Sales	$ (24.3)
Natural Gas Financial Futures/Swaps	17.7
NGLs Financial Futures/Swaps	(0.2)
Total	$ (6.8)

For derivatives designated as cash flow hedges in the tables above, amounts reclassified from Accumulated Other Comprehensive Income into income (effective portion) and amounts recognized in income (ineffective portion) for the years ended December 31, 2011, 2010 and 2009, if any, are reported in Operating Revenues. For derivatives not designated as hedges in the tables above, amounts recognized in income for the years ended December 31, 2011, 2010 and 2009, if any, are reported in Operating Revenues.

Credit-Risk Related Contingent Features in Derivative Instruments

In the event Moody's Investors Services or Standard & Poor's Ratings Services were to lower the Company's senior unsecured debt rating to a below investment grade rating, at December 31, 2011, the Company would have been required to post $2.1 million of cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position at December 31, 2011. 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.

8. Stock-Based Compensation

In 2008, the Company adopted, and its shareowners approved, the 2008 Stock Incentive Plan. Under the 2008 Stock Incentive 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 Stock Incentive Plan.

The following table summarizes the Company's pre-tax compensation expense and related income tax benefit for the years ended December 31, 2011, 2010 and 2009 related to the Company's performance units and restricted stock.

Year ended December 31 *(In millions)*	**2011**	2010	2009
Performance units			
Total shareholder return	**$ 8.2**	$ 6.8	$ 4.4
Earnings per share	**5.5**	2.5	1.4
Total performance units	**13.7**	9.3	5.8
Restricted stock	**1.0**	0.9	0.9
Total compensation expense	**$ 14.7**	$ 10.2	$ 6.7
Income tax benefit	**$ 5.7**	$ 3.9	$ 2.7

The Company has issued new shares to satisfy stock option exercises, restricted stock grants and payouts of earned performance units. In 2011, 2010 and 2009, there were 311,623 shares, 230,233 shares and 324,651 shares, respectively, of new common stock issued pursuant to the Company's stock incentive plans related to exercised stock options, restricted stock grants and payouts of earned performance units. In 2011, there were 9,258 shares of restricted stock returned to the Company to satisfy tax liabilities.

In November 2011, the Company purchased 120,000 shares of its common stock at an average cost of $51.33 per share on the open market. These shares will be used to satisfy Enogex's portion of the Company's obligation to deliver shares of common stock related to long-term incentive payouts of earned performance units in 2012. The Company expects to purchase shares in the future to satisfy a portion of its obligation under its incentive plan. The Company records treasury stock purchases at cost. Treasury stock is presented as a reduction of stockholders' equity in the Company's Consolidated Balance Sheet.

Performance Units

Under the 2008 Stock Incentive Plan, 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 2008 Stock Incentive Plan). 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 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 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 total shareholder return ranking relative to a peer group of companies. The performance units granted based on earnings per share are contingently awarded and will be payable in shares of the Company's common stock based on the Company's earnings per share 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 in the Consolidated Balance Sheet. If there is no or only a partial payout for the performance units at the end of the award cycle, the unearned performance units are cancelled. Payout requires 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.

Performance Units – Total Shareholder Return

The fair value of the performance units based on total shareholder return 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 award cycle. There are no post-vesting restrictions related to the Company's performance units based on total shareholder return. The number of performance units granted based on total shareholder return and the assumptions used to calculate the grant date fair value of the performance units based on total shareholder return are shown in the following table.

	2011	2010	2009
Number of units granted	213,721	214,750	316,513
Fair value of units granted	$ 46.09	$ 39.43	$ 25.55
Expected dividend yield	3.2%	3.9%	4.5%
Expected price volatility	33.0%	34.0%	31.0%
Risk-free interest rate	1.40%	1.42%	1.25%
Expected life of units (in years)	2.87	2.87	2.88

Performance Units – Earnings Per Share

The fair value of the performance units based on earnings per share 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 earnings per share 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 earnings per share. The number of performance units granted based on earnings per share and the grant date fair value are shown in the following table.

	2011	2010	2009
Number of units granted	71,238	71,585	105,504
Fair value of units granted	$ 41.61	$ 32.44	$ 20.02

Restricted Stock

Under the 2008 Stock Incentive Plan and beginning in 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.

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 number of shares of restricted stock granted and the grant date fair value are shown in the following table.

	2011	2010	2009
Shares of restricted stock granted	17,902	26,653	6,226
Fair value of restricted stock granted	$ 48.82	$ 40.78	$ 33.38

A summary of the activity for the Company's non-vested performance units and restricted stock at December 31, 2011 and changes in 2011 are shown in the following table.

	Performance Units				Restricted Stock	
	Total Shareholder Return		Earnings Per Share			
	Number of Units	Weighted-Average Grant Date Fair Value	Number of Units	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Units/Shares Non-Vested at 12/31/10	507,154	$ 31.40	169,054	$ 25.26	47,739	$ 36.46
Granted	213,721 (A)	$ 46.09	71,238 (A)	$ 41.61	17,902	$ 48.82
Vested	(291,294)	$ 25.55	(97,099)	$ 20.02	(28,397)	$ 34.05
Forfeited	(14,751)	$ 40.53	(4,916)	$ 34.91	—	$ —
Units/Shares Non-Vested at 12/31/11	414,830	$ 42.75	138,277	$ 37.01	37,244	$ 44.24
Units/Shares Expected to Vest	357,974		119,325		37,244	

(A) 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.

Fair Value of Vested Performance Units and Restricted Stock

A summary of the Company's fair value for its vested performance units and restricted stock is shown in the following table.

Year ended December 31 *(In millions)*	**2011**	2010	2009
Performance units			
Total shareholder return	**$ 7.4**	$ 5.4	$ 1.9
Earnings per share	**3.9**	1.9	0.5
Restricted stock	**1.0**	0.6	0.6

Unrecognized Compensation Cost

A summary of the Company's unrecognized compensation cost for its non-vested performance units and restricted stock and the weighted-average periods over which the compensation cost is expected to be recognized are shown in the following table.

December 31, 2011	Unrecognized Compensation Cost *(in millions)*	Weighted Average to be Recognized *(in years)*
Performance units		
Total shareholder return	$ 7.8	1.70
Earnings per share	3.0	1.56
Total performance units	10.8	
Restricted stock	0.9	2.33
Total	$ 11.7	

Stock Options

The Company last issued stock options in 2004 and as of December 31, 2006, all stock options were fully vested and expensed. All stock options have a contractual life of 10 years. A summary of the activity for the Company's stock options at December 31, 2011 and changes in 2011 are shown 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 12/31/10	100,344	$ 22.19		
Exercised	(44,544)	$ 20.94	$ 2.2	
Options Outstanding at 12/31/11	55,800	$ 23.19	$ 1.9	1.96 years
Options Fully Vested and Exercisable at 12/31/11	55,800	$ 23.19	$ 1.9	1.96 years

A summary of the activity for the Company's exercised stock options in 2011, 2010 and 2009 are shown in the following table.

Year ended December 31 *(In millions)*	**2011**	2010	2009
Intrinsic value (A)	**$ 2.2**	$ 2.5	$ 1.7
Cash received from stock options exercised	**1.3**	3.2	3.5
Income tax benefit realized for the tax deductions from exercised stock options (B)	**—**	1.0	0.7

(A) The difference between the market value on the date of exercise and the option exercise price.
(B) The Company did not realize an income tax benefit for the tax deductions from the exercised stock options in 2011 due to the Company being in a tax net operating loss position in 2011.

9. Supplemental Cash Flow Information

The following table discloses information about investing and financing activities that affected recognized assets and liabilities but which did 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)*	**2011**	2010	2009
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Power plant long-term service agreement	**$ 1.7**	$ 2.7	$ —
Future installment payments to wind farm developer	**—**	2.3	3.9
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash Paid During the Period for			
Interest (net of interest capitalized) (A)	**$ 138.9**	$ 144.6	$ 125.8
Income taxes (net of income tax refunds)	**4.7**	(139.5)	2.0

(A) Net of interest capitalized of $19.1 million, $8.0 million and $14.6 million in 2011, 2010 and 2009, respectively.

10. Income Taxes

The items comprising income tax expense are as follows:

Year ended December 31 *(In millions)*	**2011**	2010	2009
Provision (Benefit) for Current Income Taxes			
Federal	**$ (6.4)**	$ 15.8	$ (145.3)
State	**—**	2.3	(4.8)
Total Provision (Benefit) for Current Income Taxes	**(6.4)**	18.1	(150.1)
Provision for Deferred Income Taxes, net			
Federal	**160.3**	134.5	256.7
State	**2.9**	9.3	8.1
Total Provision for Deferred Income Taxes, net	**163.2**	143.8	264.8
Deferred Federal Investment Tax Credits, net	**(3.3)**	(3.7)	(4.2)
Income Taxes Relating to Other Income and Deductions	**7.2**	2.8	10.6
Total Income Tax Expense	**$ 160.7**	$ 161.0	$ 121.1

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 tax examinations by tax authorities for years prior to 2007 or state and local tax examinations by tax authorities for years prior to 2002. 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. OG&E earns both Federal and Oklahoma state tax credits associated with the production from its wind farms. In addition, OG&E and Enogex earn Oklahoma state tax credits associated with their investments in electric generating and natural gas processing facilities which 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	**2011**	2010	2009
Statutory Federal tax rate	**35.0 %**	35.0 %	35.0 %
Amortization of net unfunded deferred taxes	**0.7**	0.7	0.7
State income taxes, net of Federal income tax benefit	**0.6**	1.7	1.0
Medicare Part D subsidy	**0.2**	2.6	(1.1)
Qualified production activities	**—**	(0.2)	—
401(k) dividends	**(0.5)**	(0.6)	(0.7)
Federal investment tax credits, net	**(0.7)**	(0.8)	(1.1)
Income attributable to noncontrolling interest	**(1.3)**	(0.4)	—
Federal renewable energy credit (A)	**(3.4)**	(3.4)	(2.2)
Other	**0.1**	0.3	0.1
Effective income tax rate	**30.7 %**	34.9 %	31.7 %

(A) These are credits associated with the production from OG&E's wind farms.

At December 31, 2011 and 2010, the Company had no material unrecognized tax benefits related to uncertain tax positions.

The deferred tax provisions are recognized as costs in the ratemaking process by the commissions having jurisdiction over the rates charged by OG&E. The components of Deferred Income Taxes at December 31, 2011 and 2010, respectively, were as follows:

December 31 *(In millions)*	**2011**	2010
Current Deferred Income Tax Assets		
Net operating losses	**$ 15.8**	$ —
Accrued liabilities	**13.2**	8.2
Accrued vacation	**4.2**	6.1
Uncollectible accounts	**1.4**	0.6
Other	**—**	2.8
Total Current Deferred Income Tax Assets	**34.6**	17.7
Current Accrued Income Tax Liabilities		
Derivative instruments	**(2.5)**	1.0
Total Current Accrued Income Tax Liabilities	**(2.5)**	1.0
Current Deferred Income Tax Assets, net	**$ 32.1**	$ 18.7
Non-Current Deferred Income Tax Liabilities		
Accelerated depreciation and other property related differences	**$ 1,449.6**	$ 1,071.4
Investment in Enogex Holdings	**571.8**	376.1
Company pension plan	**67.5**	71.4
Regulatory asset	**21.2**	17.2
Income taxes refundable to customers, net	**15.9**	16.8
Bond redemption-unamortized costs	**4.4**	4.8
Derivative instruments	**—**	22.4
Total Non-Current Deferred Income Tax Liabilities	**2,130.4**	1,580.1
Non-Current Deferred Income Tax Assets		
Net operating losses	**(225.2)**	—
Regulatory liabilities	**(65.3)**	(43.7)
State tax credits	**(63.0)**	(35.5)
Postretirement medical and life insurance benefits	**(50.2)**	(39.0)
Federal tax credits	**(49.7)**	(21.5)
Derivative instruments	**(12.8)**	—
Deferred Federal investment tax credits	**(2.3)**	(3.6)
Other	**(10.5)**	(2.0)
Total Non-Current Deferred Income Tax Assets	**(479.0)**	(145.3)
Non-Current Deferred Income Tax Liabilities, net	**$ 1,651.4**	$ 1,434.8

During 2010 and 2011, the Company had a Federal tax operating loss primarily caused by the accelerated tax "bonus" depreciation provision contained within the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 which allows the Company to record a current income tax deduction for 100 percent of the cost of certain property placed into service from September 8, 2010 to December 31, 2011. In addition, the new law also allows the Company to record a current income tax deduction for 50 percent of the cost of certain property placed into service from January 1, 2012 to December 31, 2012. For financial accounting purposes, the Company recorded an increase in its Non-Current Deferred Income Taxes Liability at December 31, 2011 and 2010 on the Company's Consolidated Balance Sheet to recognize the financial statement impact of this new law.

In June 2010, new legislation was passed in Oklahoma that created a moratorium, from July 1, 2010 through June 30, 2012, on 30 income tax credits. For income tax purposes, credits affected by the moratorium may not be claimed for any event, transaction, investment, expenditure or other act for which the credits would otherwise be allowable. During this two-year period, affected credits generated by the Company are being deferred and will be utilized at a time after the moratorium expires. For financial accounting purposes, the Company will receive the benefits in the future as most of these credits do not expire if they are not utilized in the period they are generated.

Medicare Part D Subsidy

On March 23, 2010, the Patient Protection and Affordable Care Act of 2009 was signed into law, and, on March 30, 2010, the Health Care and Education Reconciliation Act of 2010, which makes various amendments to certain aspects of the Patient Protection and Affordable Care Act of 2009, was signed into law. These Acts effectively change the tax treatment of Federal subsidies paid to sponsors of retiree health benefit plans that provide prescription drug benefits that are at least actuarially equivalent to the corresponding benefits provided under Medicare Part D.

The Federal subsidy paid to employers was introduced as part of the Medicare Prescription Drug, Improvement, and Modernization Act of 2003. The Company has been recognizing the Federal subsidy since 2005 related to certain retiree prescription drug plans that were determined to be actuarially equivalent to the benefit provided under Medicare Part D. Under the Medicare Prescription Drug, Improvement, and Modernization Act of 2003, the Federal subsidy does not reduce an employer's income tax deduction for the costs of providing such prescription drug plans nor is it subject to income tax individually.

During 2011, the Company modified its retiree health benefit plan in such a manner that it is no longer actuarially equivalent to the corresponding benefits provided under Medicare Part D. As a result, the Company is no longer eligible to receive Medicare Part D reimbursements. See Note 14 for a further discussion.

Other

The Company sustained Federal and state tax operating losses in 2010 and 2011 caused primarily by bonus depreciation and other book verses tax temporary differences. As a result, the Company accrued Federal and state income tax benefits in 2010 and 2011. The Company can no longer carry these losses back to prior periods, therefore, these losses are being carried forward. In addition to the operating losses, the Company was unable to utilize the various tax credits that were generating during these years. These tax losses and credits are being carried as deferred tax assets and will be utilized in future periods. The Company anticipates future taxable income will be sufficient to utilize all of the losses and credits before they begin to expire, accordingly no valuation allowance is considered necessary. The following table summarizes these carry forwards:

(In millions)	Carry Forward Amount	Deferred Tax Asset	Earliest Expiration Date
Net operating losses			
State operating loss	$ 772.9	$ 28.4	2030
Federal operating loss	607.2	212.6	2030
Federal tax credits	49.7	49.7	2029
State tax credits			
Oklahoma investment tax credits	76.3	49.7	N/A
Oklahoma capital investment board credits (A)	7.3	7.3	2015
Oklahoma zero emission tax credits	8.4	6.0	2020

(A) Oklahoma capital investment board credits may not be exercisable after July 1, 2015. The Company anticipates the credits will be monetized or the expiration date of these credits will be extended.

The Company expects that $45.0 million of the tax loss carry forward will be utilized in 2012 and, as a result, a current deferred tax asset of $15.8 million was recorded at December 31, 2011. The remaining $225.2 million was recorded as a non-current deferred tax asset and is expected to be realized in periods after 2012.

11. Common Equity

Automatic Dividend Reinvestment and Stock Purchase Plan

The Company issued 277,245 shares of common stock under its Automatic Dividend Reinvestment and Stock Purchase Plan in 2011 and received proceeds of $13.8 million. The Company may, from time to time, issue additional shares under its Automatic Dividend Reinvestment and Stock Purchase Plan to fund capital requirements or working capital needs. At December 31, 2011, there were 2,369,043 shares of unissued common stock reserved for issuance under the Company's Automatic Dividend Reinvestment and Stock Purchase Plan.

Earnings Per Share

Basic earnings per share is calculated by dividing net income attributable to OGE Energy by the weighted average number of the Company's common shares outstanding during the period. In the calculation of diluted earnings per share, weighted average shares outstanding are increased for additional shares that would be outstanding if potentially dilutive securities were converted to common stock. Potentially dilutive securities for the Company consist of performance units. Basic and diluted earnings per share for the Company were calculated as follows:

(In millions)	**2011**	2010	2009
Net Income Attributable to OGE Energy	**$ 342.9**	$ 295.3	$ 258.3
Average Common Shares Outstanding			
Basic average common shares outstanding	**97.9**	97.3	96.2
Effect of dilutive securities:			
Contingently issuable shares (performance units)	**1.3**	1.6	1.0
Diluted average common shares outstanding	**99.2**	98.9	97.2
Basic Earnings Per Average Common Share			
Attributable to OGE Energy Common Shareholders	**$ 3.50**	$ 3.03	$ 2.68
Diluted Earnings Per Average Common Share			
Attributable to OGE Energy Common Shareholders	**$ 3.45**	$ 2.99	$ 2.66
Anti-dilutive shares excluded from earnings per share calculation	**—**	—	—

12. Long-Term Debt

A summary of the Company's long-term debt is included in the Consolidated Statements of Capitalization. At December 31, 2011, the Company was in compliance with all of its debt agreements.

OG&E has tax-exempt pollution control 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:

SERIES	**DATE DUE**	**AMOUNT**
		(In millions)
0.22% - 0.44%	Garfield Industrial Authority, January 1, 2025	$ 47.0
0.20% - 0.44%	Muskogee Industrial Authority, January 1, 2025	32.4
0.24% - 0.50%	Muskogee Industrial Authority, June 1, 2027	56.0
Total (redeemable during next 12 months)		$ 135.4

All of these bonds are subject to an optional tender at the request of the holders, at 100 percent of the principal amount, together with accrued and unpaid interest to the date of purchase. The bond holders, on any business day, can request repayment of the bond by delivering an irrevocable notice to the tender agent stating the principal amount of the bond, payment instructions for the purchase price and the business day the bond is to be purchased. The repayment option may only be exercised by the holder of a bond for the principal amount. When a tender notice has been received by the trustee, a third party remarketing agent for the bonds will attempt to remarket any bonds tendered for purchase. This process occurs once per week. Since the original issuance of these series of bonds in 1995 and 1997, the remarketing agent has successfully remarketed all tendered bonds. If the remarketing agent is unable to remarket any such bonds, OG&E is obligated to repurchase such unremarketed bonds. As OG&E has both the intent and ability to refinance the bonds on a long-term basis and such ability is supported by an ability to consummate the refinancing, the bonds are classified as long-term debt in the Company's Consolidated Financial Statements. OG&E believes that it has sufficient liquidity to meet these obligations.

Long-Term Debt Maturities

Maturities of the Company's long-term debt during the next five years consist of $300 million and $260 million in years 2014 and 2016, respectively. There are no maturities of the Company's long-term debt in years 2012, 2013 or 2015.

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.

OG&E Issuance of Long-Term Debt

On May 24, 2011, OG&E issued $250 million of 5.25% senior notes due May 15, 2041. The proceeds from the issuance were added to OGE Energy's general funds and were used to repay short-term debt. OG&E expects to issue additional long-term debt from time to time when market conditions are favorable and when the need arises.

13. Short-Term Debt and Credit Facilities

The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The short-term debt balance was $277.1 million and $145.0 million at December 31, 2011 and 2010, respectively, at a weighted-average interest rate of 0.48 percent and 0.34 percent, respectively. The following table provides information regarding the Company's revolving credit agreements and available cash at December 31, 2011.

Revolving Credit Agreements and Available Cash

Entity	Aggregate Commitment	Amount Outstanding (A)	Weighted-Average Interest Rate	Maturity	
	(In millions)				
OGE Energy (B)	$ 750.0	$ 277.1	0.48% (D)	December 13, 2016	(F)
OG&E (C)	400.0	2.2	0.53% (D)	December 13, 2016	(F)
Enogex LLC (E)	400.0	150.0	1.65% (D)	December 13, 2016	(F)
	1,550.0	429.3	0.89%		
Cash	4.6	N/A	N/A	N/A	
Total	$ 1,554.6	$ 429.3	0.89%		

(A) Includes direct borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit at December 31, 2011.
(B) 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, 2011, there was $277.1 million in outstanding commercial paper borrowings.
(C) 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, 2011, there was $2.2 million supporting letters of credit.
(D) Represents the weighted-average interest rate for the outstanding borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit.
(E) This bank facility is available to provide revolving credit borrowings for Enogex LLC. As Enogex LLC's credit agreement matures on December 13, 2016, along with its intent in utilizing its credit agreement, borrowings thereunder are classified as long-term debt in the Company's Consolidated Balance Sheets.
(F) In December 2011, the Company, OG&E and Enogex LLC each entered into new unsecured five-year revolving credit facilities totaling in the aggregate $1,550 million ($750 million for the Company, $400 million for OG&E and $400 million for Enogex LLC). Each of the credit facilities contain an option, which may be exercised up to two times, to extend the term for an additional year.

The Company's ability to access the commercial paper market could be adversely impacted by a credit ratings downgrade or major market disruptions. Pricing grids associated with the Company's credit facilities could cause annual fees and borrowing rates to increase if an adverse ratings impact occurs. The impact of any future downgrade could include an increase in the costs of the Company's short-term borrowings, but a reduction in the Company's credit ratings would not result in any defaults or accelerations. Any future downgrade of the Company could 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.

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, 2011 and ending December 31, 2012.

14. Retirement Plans and Postretirement Benefit Plans

Pension Plan and Restoration of Retirement Income Plan

In October 2009, the Company's Pension Plan and the Company's 401(k) Plan were amended, effective January 1, 2010 to provide eligible employees a choice to select a future retirement benefit combination from the Company's Pension Plan and the Company's 401(k) Plan.

Employees hired or rehired on or after December 1, 2009 do not participate in the Pension Plan but are eligible to participate in the 401(k) Plan where, for each pay period, the Company contributes to the 401(k) Plan, on behalf of each participant, 200 percent of the participant's contributions up to five percent of compensation.

It is the Company's policy to fund the Pension Plan on a current basis based on the net periodic pension expense as determined by the Company's actuarial consultants. During each of 2011 and 2010, OGE Energy made contributions to its Pension Plan of $50 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. During 2012, OGE Energy may contribute up to $35 million to its Pension Plan. The expected contribution to the Pension Plan during 2012 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. OGE Energy could be required to make additional contributions if the value of its pension trust and postretirement benefit plan trust assets are adversely impacted by a major market disruption in the future.

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

The following table presents the status of the Company's Pension Plan and Restoration of Retirement Income Plan at December 31, 2011 and 2010. 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 those recorded as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

	Pension Plan		Restoration of Retirement Income Plan	
December 31 *(In millions)*	**2011**	2010	**2011**	2010
Benefit obligations	**$ (697.7)**	$ (640.9)	**$ (13.3)**	$ (10.8)
Fair value of plan assets	**589.8**	574.0	**—**	—
Funded status at end of year	**$ (107.9)**	$ (66.9)	**$ (13.3)**	$ (10.8)

The following table summarizes the benefit payments the Company expects to pay related to its Pension Plan and Restoration of Retirement Income Plan. 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.

(In millions)	Projected Benefit Payments
2012	$ 68.2
2013	69.2
2014	87.0
2015	78.3
2016	71.1
2017 and Beyond	303.3

Plan Investments, Policies and Strategies

The Pension Plan assets are held in a trust which follows an investment policy and strategy designed to reduce the funded status volatility of the Plan by utilizing liability driven investing. The purpose of liability driven investing is to structure the asset portfolio to more closely resemble the pension liability and thereby more effectively hedge against changes in the liability. The investment policy follows a glide path approach that shifts a higher portfolio weighting to fixed income as the Plan's funded status increases. The table below sets forth the targeted fixed income and equity allocations at different funded status levels.

Projected Benefit Obligation Funded Status Thresholds	<90%	95%	100%	105%	110%	115%	120%
Fixed income	50%	58%	65%	73%	80%	85%	90%
Equity	50%	42%	35%	27%	20%	15%	10%
Total	100%	100%	100%	100%	100%	100%	100%

Within the portfolio's overall allocation to equities, the funds are allocated according to the guidelines in the table below.

Asset Class	Target Allocation	Minimum	Maximum
Domestic All-Cap/Large Cap Equity	50%	50%	60%
Domestic Mid-Cap Equity	15%	5%	25%
Domestic Small-Cap Equity	15%	5%	25%
International Equity	20%	10%	30%

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 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 each investment manager's respective portfolio.

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 percent 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)
Core Fixed Income	Barclays Capital Aggregate Index
Interest Rate Sensitive Fixed Income	Barclays Capital Aggregate Index
Long Duration Fixed Income	Barclays Capital Aggregate Index
Equity Index	Standard & Poor's 500 Index
All-Cap Equity	Russell 3000 Index
	Russell 3000 Value Index
Mid-Cap Equity	Russell Midcap Index
	Russell Midcap Value Index
Small-Cap Equity	Russell 2000 Index
	Russell 2000 Value Index
International Equity	Morgan Stanley Capital International ACWI ex-US

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

The domestic value equity managers focus on stocks that the manager believes are undervalued in price and earn an average or less than average return on assets, and often pays out higher than average dividend payments. The domestic growth equity manager will invest primarily in growth companies which consistently experience above average growth in earnings and sales, earn a high return on assets, and reinvest cash flow into existing business. The domestic mid-cap equity portfolio manager focuses on companies with market capitalizations lower than the average company traded on the public exchanges with the following characteristics: price/earnings ratio at or near the Russell Midcap Index, small dividend yield, return on equity at or near the Russell Midcap Index and an earnings per share growth rate at or near the Russell Midcap Index. The domestic small-cap 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 an 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 All Country World ex-US Index is the benchmark for comparative performance purposes. The Morgan Stanley Capital International All Country World ex-US Index is a market value weighted index designed to measure the combined equity market performance of developed and emerging markets countries, excluding the United States. All of the equities which are purchased for the international portfolio are thoroughly researched. Only companies with a market capitalization in excess of $100 million are allowable. No more than five percent of the portfolio can be invested in any one stock at the time of purchase. All securities are freely traded on a recognized stock exchange and there are no 144-A securities and no over-the-counter derivatives. The following investment categories are excluded: options (other than traded currency options), commodities, futures (other than currency futures or currency hedging), short sales/margin purchases, private placements, unlisted securities and real estate (but not real estate shares).

For all domestic equity investment managers, no more than eight percent (five percent for mid-cap and small-cap equity managers) can be invested in any one stock at the time of purchase and no more than 16 percent (10 percent for mid-cap and small-cap equity managers) after accounting for price appreciation. Options or financial futures may not be purchased unless prior approval of the Company's 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.

Plan Investments

The following tables summarize the Pension Plan's investments that are measured at fair value on a recurring basis at December 31, 2011 and 2010. There were no Level 3 investments held by the Pension Plan at December 31, 2011 and 2010.

(In millions)	December 31, 2011	Level 1	Level 2
Common stocks			
U.S. common stocks	**$ 179.7**	**$ 179.7**	**$ —**
Foreign common stocks	**59.5**	**59.5**	**—**
Bonds, debentures and notes (A)			
Corporate fixed income and other securities	**95.3**	**—**	**95.3**
Mortgage-backed securities	**17.2**	**—**	**17.2**
U.S. Government obligations			
U.S. treasury notes and bonds (B)	**118.8**	**118.8**	**—**
Mortgage-backed securities	**72.0**	**—**	**72.0**
Other securities	**1.0**	**—**	**1.0**
Commingled fund (C)	**38.5**	**—**	**38.5**
Common/collective trust (D)	**29.6**	**—**	**29.6**
Foreign government bonds	**2.9**	**—**	**2.9**
Interest-bearing cash	**2.1**	**2.1**	**—**
U.S. municipal bonds	**1.7**	**—**	**1.7**
Preferred stocks (foreign)	**0.6**	**0.6**	**—**
Total Plan investments	**$ 618.9**	**$ 360.7**	**$ 258.2**
Receivable from broker for securities sold	**4.8**		
Interest and dividends receivable	**3.1**		
Payable to broker for securities purchased	**(37.0)**		
Total Plan assets	**$ 589.8**		

(In millions)	December 31, 2010	Level 1	Level 2
Common stocks			
U.S. common stocks	$ 189.0	$ 189.0	$ —
Foreign common stocks	75.9	75.9	—
Bonds, debentures and notes (A)			
Corporate fixed income and other securities	104.1	—	104.1
Mortgage-backed securities	26.6	—	26.6
U.S. Government obligations			
Mortgage-backed securities	76.5	—	76.5
U.S. treasury notes and bonds (B)	35.7	35.7	—
Other securities	2.4	—	2.4
Commingled fund (C)	37.7	—	37.7
Common/collective trust (D)	23.1	—	23.1
Mutual funds			
Global equity mutual fund	1.8	1.8	—
U.S equity mutual fund	1.6	1.6	—
Foreign equity mutual fund	1.0	1.0	—
U.S. municipal bonds	4.3	—	4.3
Foreign government bonds	3.9	—	3.9
Repurchase agreement	3.7	—	3.7
Preferred stocks (foreign)	0.7	0.7	—
Interest-bearing cash	0.2	0.2	—
Total Plan investments	$ 588.2	$ 305.9	$ 282.3
Receivable from broker for securities sold	5.5		
Interest and dividends receivable	2.8		
Payable to broker for securities purchased	(22.5)		
Total Plan assets	$ 574.0		

(A) This category primarily represents U.S. corporate bonds with an investment grade rating at or above Baa3 or BBB- by Moody's Investors Services, Standard & Poor's Ratings Services or Fitch Ratings.

(B) This category represents U.S. treasury notes and bonds with a Moody's Investors Services rating of Aaa and Government Agency Bonds with a Moody's Investors Services rating of A1 or higher.

(C) This category represents units of participation in a commingled fund that primarily invest in stocks and bonds of U.S. companies.
(D) This category represents units of participation in an investment pool which primarily invests in foreign or domestic bonds, debentures, mortgages, equipment or other trust certificates, notes, obligations issued or guaranteed by the U.S. Government or its agencies, bank certificates of deposit, bankers' acceptances and repurchase agreements, high grade commercial paper and other instruments with money market characteristics with a fixed or variable interest rate. There are no restrictions on redemptions in the common/collective trust.

The three levels defined in the fair value hierarchy and examples of each are as follows:

Level 1 inputs are quoted prices in active markets for identical unrestricted assets or liabilities that are accessible by the Pension Plan at the measurement date. Instruments classified as Level 1 include investments in common and preferred stocks, U.S. treasury notes and bonds, mutual funds and interest-bearing cash.

Level 2 inputs are inputs other than quoted prices in active markets included within Level 1 that are either directly or indirectly observable at the reporting date for the asset or liability for substantially the full term of the asset or liability. Level 2 inputs include quoted prices for similar assets or liabilities in active markets and quoted prices for identical or similar assets or liabilities in markets that are not active. Instruments classified as Level 2 include corporate fixed income and other securities, mortgage-backed securities, other U.S. Government obligations, commingled fund, a common/collective trust, U.S. municipal bonds, foreign government bonds, a repurchase agreement, money market fund and forward contracts.

Level 3 inputs are prices or valuation techniques for the asset or liability that require inputs that are both significant to the fair value measurement and unobservable (i.e., supported by little or no market activity). Unobservable inputs reflect the Plan's own assumptions about the assumptions that market participants would use in pricing the asset or liability (including assumptions about risk).

Postretirement Benefit Plans

In addition to providing pension benefits, the Company provides certain medical and life insurance benefits for eligible retired members. 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 at least age 55 with 10 or more years of 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. Effective January 1, 2010, the age for dependents to participate in the Company's Medical Plan was increased to age 21 and if the dependent is a full-time student to age 26. Effective July 1, 2010, the age for dependents to participate in the Company's Medical Plan was increased to age 26 without regard to their full-time student status. All regular, full-time, active employees whose age and years of credited service total or exceed 80 or have attained at least age 55 with three or more years of 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 postretirement benefit costs and includes an annual amount as a component of the cost-of-service in future ratemaking proceedings.

In January 2011, the Company adopted several amendments to its retiree medical plan. Effective January 1, 2012, medical costs for pre-65 aged eligible retirees are fixed at the 2011 level and the Company covers future annual medical inflationary cost increases up to five percent. Increases in excess of five percent annually are covered by the pre-65 aged retiree in the form of premium increases. Also, effective January 1, 2012, the Company supplements Medicare coverage for Medicare-eligible retirees, providing them a fixed stipend based on the Company's expected average 2011 premium for medical and drug coverage, and allows those Medicare-eligible retirees to acquire coverage from a Company-provided third-party administrator. The effect of these plan amendments was reflected in the Company's 2011 Consolidated Balance Sheet as a reduction to the accumulated postretirement benefit obligation of $91.3 million, an increase in other comprehensive income of $16.9 million and a reduction to OG&E's benefit obligations regulatory asset of $74.4 million.

Plan Investments

The following tables summarize the postretirement benefit plans investments that are measured at fair value on a recurring basis at December 31, 2011 and 2010. There were no Level 2 investments held by the postretirement benefit plans at December 31, 2011 and 2010.

(In millions)	December 31, 2011	Level 1	Level 3
Group retiree medical insurance contract (A)	**$ 54.3**	**$ —**	**$ 54.3**
Mutual funds investment			
U.S. equity investments	**5.3**	**5.3**	**—**
Money market funds investment	**0.7**	**0.7**	**—**
Cash	**0.7**	**0.7**	**—**
Total Plan investments	**$ 61.0**	**$ 6.7**	**$ 54.3**

(In millions)	December 31, 2010	Level 1	Level 3
Group retiree medical insurance contract (A)	$ 52.4	$ —	$ 52.4
Mutual funds investment			
U.S. equity investments	5.5	5.5	—
Money market funds investment	0.6	0.6	—
Total Plan investments	$ 58.5	$ 6.1	$ 52.4

(A) This category represents a group retiree medical insurance contract which invests in a pool of common stocks, bonds and money market accounts, of which a significant portion is comprised of mortgage-backed securities.

The postretirement benefit plans Level 3 investment includes an investment in a group retiree medical insurance contract. The unobservable input included in the valuation of the contract includes the approach for determining the allocation of the postretirement benefit plans pro-rata share of the total assets in the contract.

The following table summarizes the postretirement benefit plans investments that are measured at fair value on a recurring basis using significant unobservable inputs (Level 3).

Year ended December 31 *(In millions)*	**2011**
Group retiree medical insurance contract	
Beginning balance	**$ 52.4**
Interest income	**1.3**
Net unrealized gains related to instruments held at the reporting date	**0.9**
Dividend income	**0.8**
Realized gains	**0.1**
Administrative expenses and charges	**(0.1)**
Claims paid	**(1.1)**
Ending balance	**$ 54.3**

The following table presents the status of the Company's postretirement benefit plans at December 31, 2011 and 2010. 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 those recorded as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

December 31 *(In millions)*	**2011**	2010
Benefit obligations	**$ (280.6)**	$ (337.1)
Fair value of plan assets	**61.0**	58.5
Funded status at end of year	**$ (219.6)**	$ (278.6)

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 8.75 percent in 2012 with the rates trending downward to 4.48 percent by 2028. 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)*	**2011**	2010	2009
Effect on aggregate of the service and interest cost components	**$ —**	$ 3.1	$ 2.4
Effect on accumulated postretirement benefit obligations	**0.1**	0.7	40.3

ONE-PERCENTAGE POINT DECREASE			
Year ended December 31 *(In millions)*	**2011**	2010	2009
Effect on aggregate of the service and interest cost components	**$ 0.1**	$ 2.5	$ 1.9
Effect on accumulated postretirement benefit obligations	**0.6**	1.6	32.9

Medicare Prescription Drug, Improvement and Modernization Act of 2003

On December 8, 2003, President Bush signed into law the Medicare Prescription Drug, Improvement and Modernization Act of 2003, which expanded Medicare to include, for the first time, coverage for prescription drugs. The following table summarizes the gross benefit payments the Company expects to pay related to its postretirement benefit plans, including prescription drug benefits. The Company received $1.3 million in Federal subsidy receipts in 2011. Due to amendments in the Company's retiree medical plan discussed above, the Company does not expect to receive any additional Federal subsidies in the future.

(In millions)	Gross Projected Postretirement Benefit Payments
2012	$ 15.4
2013	16.0
2014	16.9
2015	17.7
2016	18.3
2017 and Beyond	97.0

Early Retiree Reinsurance Program

The Patient Protection and Affordable Care Act of 2010 authorized a temporary reinsurance program to pay certain employment-based group health plans up to 80 percent of each early retiree's annual claims cost between $15,000 and $90,000. The program will end by the earlier of January 1, 2014 or when the limited $5 billion in funding runs out. The Company received $0.7 million in Federal subsidy receipts in 2011. The Company's reimbursement proceeds are excluded from gross income and were used to reduce the health benefit costs for the plan and to reduce premium contributions for the plan participants. The Company does not expect to receive any additional benefits provided by this program.

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 2011 and 2010. 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 postretirement benefit obligation. The accumulated postretirement benefit obligation for the Company's Pension Plan and Restoration of Retirement Income Plan differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. The accumulated postretirement benefit obligation for the Pension Plan and the Restoration of Retirement Income Plan at December 31, 2011 was $656.1 million and $11.9 million, respectively. The accumulated postretirement benefit obligation for the Pension Plan and the Restoration of Retirement Income Plan at December 31, 2010 was $601.4 million and $8.7 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:

December 31 *(In millions)*	Pension Plan 2011	Pension Plan 2010	Restoration of Retirement Income Plan 2011	Restoration of Retirement Income Plan 2010	Postretirement Benefit Plans 2011	Postretirement Benefit Plans 2010
Change in Benefit Obligation						
Beginning obligations	**$ (640.9)**	$ (610.9)	**$ (10.8)**	$ (8.3)	**$ (337.1)**	$ (288.0)
Service cost	**(17.6)**	(16.7)	**(1.0)**	(0.9)	**(3.5)**	(4.3)
Interest cost	**(33.3)**	(31.8)	**(0.6)**	(0.5)	**(12.5)**	(17.0)
Plan amendments	**—**	—	**—**	—	**91.4**	—
Participants' contributions	**—**	—	**—**	—	**(8.1)**	(7.3)
Medicare subsidies received	**—**	—	**—**	—	**(2.0)**	(1.4)
Actuarial gains (losses)	**(48.3)**	(15.9)	**(1.0)**	(1.5)	**(25.7)**	(36.6)
Benefits paid	**42.4**	34.4	**0.1**	0.4	**16.9**	17.5
Ending obligations	**$ (697.7)**	$ (640.9)	**$ (13.3)**	$ (10.8)	**$ (280.6)**	$ (337.1)
Change in Plans' Assets						
Beginning fair value	**$ 574.0**	$ 496.3	**$ —**	$ —	**$ 58.5**	$ 55.0
Actual return on plans' assets	**8.2**	62.1	**—**	—	**2.7**	5.2
Employer contributions	**50.0**	50.0	**0.1**	0.4	**6.6**	7.1
Participants' contributions	**—**	—	**—**	—	**8.1**	7.3
Medicare subsidies received	**—**	—	**—**	—	**2.0**	1.4
Benefits paid	**(42.4)**	(34.4)	**(0.1)**	(0.4)	**(16.9)**	(17.5)
Ending fair value	**589.8**	574.0	**—**	—	**61.0**	58.5
Funded status at end of year	**$ (107.9)**	$ (66.9)	**$ (13.3)**	$ (10.8)	**$ (219.6)**	$ (278.6)

Net Periodic Benefit Cost

Year ended December 31 *(In millions)*	Pension Plan 2011	Pension Plan 2010	Pension Plan 2009	Restoration of Retirement Income Plan 2011	Restoration of Retirement Income Plan 2010	Restoration of Retirement Income Plan 2009	Postretirement Benefit Plans 2011	Postretirement Benefit Plans 2010	Postretirement Benefit Plans 2009
Service cost	**$ 17.6**	$ 16.7	$ 18.1	**$ 1.0**	$ 0.9	$ 0.7	**$ 3.5**	$ 4.3	$ 3.3
Interest cost	**33.3**	31.8	31.4	**0.6**	0.5	0.4	**12.5**	17.0	14.1
Expected return on plan assets	**(45.5)**	(42.4)	(33.0)	**—**	—	—	**(5.1)**	(6.9)	(6.5)
Amortization of transition obligation	**—**	—	—	**—**	—	—	**2.7**	2.7	2.7
Amortization of net loss	**19.2**	21.3	23.5	**0.4**	0.3	0.3	**18.3**	12.1	5.0
Amortization of unrecognized prior service cost (A)	**2.4**	2.4	0.8	**0.7**	0.7	0.6	**(16.5)**	—	1.0
Net periodic benefit cost (B)	**$ 27.0**	$ 29.8	$ 40.8	**$ 2.7**	$ 2.4	$ 2.0	**$ 15.4**	$ 29.2	$ 19.6

(A) Unamortized prior service cost is amortized on a straight-line basis over the average remaining service period to the first eligibility age of participants who are expected to receive a benefit and are active at the date of the plan amendment.
(B) In addition to the $45.1 million, $61.4 million and $62.4 million of net periodic benefit cost recognized in 2011, 2010 and 2009, respectively, the Company recognized the following:

- an increase in pension expense in 2011 and 2010 of $10.8 million and $8.1 million, respectively, and a reduction in pension expense in 2009 of $2.2 million to maintain the allowable amount to be recovered for pension expense in the Oklahoma jurisdiction which are included in the Pension tracker regulatory liability (see Note 1);
- a reduction in pension expense in 2009 of $3.2 million in the Arkansas jurisdiction to reflect the approval of recovery of OG&E's 2006 and 2007 pension settlement costs in the May 2009 Arkansas rate order which are included in the Pension tracker regulatory liability) (see Note 1); and
- an increase in postretirement medical expense in 2011 of $3.5 million to maintain the allowable amount to be recovered for postretirement medical expense in the Oklahoma jurisdiction which are included in the Pension tracker regulatory liability (see Note 1).

The capitalized portion of the net periodic pension benefit cost was $6.1 million, $6.5 million and $8.4 million at December 31, 2011, 2010 and 2009, respectively. The capitalized portion of the net periodic postretirement benefit cost was $3.8 million, $6.5 million and $4.1 million at December 31, 2011, 2010 and 2009, respectively.

Rate Assumptions

	Pension Plan and Restoration of Retirement Income Plan			Postretirement Benefit Plans		
Year ended December 31	**2011**	2010	2009	**2011**	2010	2009
Discount rate	**4.50%**	5.30%	5.30%	**4.50%**	5.30%	6.00%
Rate of return on plans' assets	**8.00%**	8.50%	8.50%	**6.50%**	8.50%	8.50%
Compensation increases	**4.40%**	4.40%	4.50%	**N/A**	N/A	N/A
Assumed health care cost trend:						
Initial trend	**N/A**	N/A	N/A	**8.75%**	8.99%	9.49%
Ultimate trend rate	**N/A**	N/A	N/A	**4.48%**	5.00%	5.00%
Ultimate trend year	**N/A**	N/A	N/A	**2028**	2020	2018

N/A - not applicable

The overall expected rate of return on plan assets assumption decreased from 8.50 percent in 2010 to 8.00 percent in 2011 in determining net periodic benefit cost due to recent returns on the Company's long-term investment portfolio. 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 $2.4 million and $2.1 million at December 31, 2011 and 2010, respectively.

401(k) Plan

The Company provides a 401(k) Plan. Each regular full-time employee of the Company or a participating affiliate is eligible to participate in the 401(k) Plan immediately. All other employees of the Company or a participating affiliate are eligible to become participants in the 401(k) Plan after completing one year of service as defined in the 401(k) Plan. Participants may contribute each pay period any whole percentage between two percent and 19 percent of their compensation, as defined in the 401(k) Plan, for that pay period. 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 401(k) Plan also allows an eligible automatic contribution arrangement and provides for a qualified default investment alternative consistent with the U.S. Department of Labor regulations. Participants may elect, in accordance with the 401(k) Plan procedures, to have his or her salary deferral rate to be made in the future automatically increased annually on a date and in an amount as specified by the participant in such election. The 401(k) Plan was amended in October 2009, as discussed previously, whereby employees were offered a choice to either stay in the 401(k) Plan (prior to it being amended) where the Company matching contributions are discussed below or select an option whereby, effective January 1, 2010, the Company contributes on behalf of each participant, depending on the option selected, 200 percent of the participant's contributions up to five percent of compensation or 100 percent of the participant's contributions up to six percent of compensation. In the 401(k) Plan (prior to it being amended), the Company contributes to the 401(k) Plan each pay period, on behalf of each participant, an amount equal to 50 percent of the participant's contributions up to six percent of compensation for participants whose employment or re-employment date occurred before February 1, 2000 and who have less than 20 years of service, as defined in the 401(k) Plan, and an amount equal to 75 percent of the participant's contributions up to six percent of compensation for participants whose employment or re-employment date occurred before February 1, 2000 and who have 20 or more years of service, as defined in the 401(k) Plan. For participants whose employment or re-employment date occurred on or after February 1, 2000 and before December 1, 2009, under the 401(k) Plan (prior to it being amended), the Company contributes 100 percent of the participant's contributions up to six percent of compensation. For participants hired on or after December 1, 2009, the Company contributes, effective January 1, 2010, 200 percent of the participant's contributions up to five percent of compensation. No Company contributions are made with respect to a participant's Catch-Up Contributions, rollover contributions, or with respect to a participant's 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. Prior to January 1, 2010, the Company's contribution, which was initially allocated for investment to the OGE Energy Corp. Common Stock Fund, was made in shares of the Company's common stock or in cash which was used to invest in the Company's common stock. Once made, the Company's contribution could be reallocated, on any business day, by participants to other available investment options. The 401(k) Plan was amended effective January 1, 2010, whereby the Company's contribution may be directed to any available investment option in the 401(k) Plan. 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 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 contributed $12.3 million, $11.4 million and $9.3 million in 2011, 2010 and 2009, respectively, to the 401(k) Plan.

Deferred Compensation Plan

The Company provides a nonqualified deferred compensation plan which is intended to be an unfunded 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' 401(k) 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 annual 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 401(k) Plan with such deferrals to start when maximum deferrals to the qualified 401(k) 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 make up for any match lost in the 401(k) Plan because of deferrals to the deferred compensation plan, and to allow for a match that would have been made under the 401(k) Plan on that portion of either the first six percent of total compensation or the first five percent of total compensation, depending on the option the participant elected under the choice provided to eligible employees discussed above, deferred that exceeds the limits allowed in the 401(k) 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. The deferred compensation plan was amended, effective January 1, 2012, to provide for full vesting after three years. 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 and Restoration of Retirement Income Plan. The supplemental executive retirement plan is intended to be an unfunded plan and not subject to the benefit limits imposed by the Code.

15. Report of Business Segments

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. Other Operations primarily includes 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, 2011, 2010 and 2009.

2011	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
(In millions)							
Operating revenues	**$ 2,211.5**	**$ 410.5**	**$ 1,167.1**	**$ 678.0**	**$ —**	**$ (551.2)**	**$ 3,915.9**
Cost of goods sold	**1,013.5**	**253.3**	**870.7**	**688.1**	**—**	**(547.7)**	**2,277.9**
Gross margin on revenues	**1,198.0**	**157.2**	**296.4**	**(10.1)**	**—**	**(3.5)**	**1,638.0**
Other operation and maintenance	**436.0**	**46.5**	**111.8**	**7.3**	**(17.3)**	**(3.1)**	**581.2**
Depreciation and amortization	**216.1**	**21.6**	**55.6**	**0.4**	**13.4**	**—**	**307.1**
Impairment of assets	**—**	**—**	**6.3**	**—**	**—**	**—**	**6.3**
Gain on insurance proceeds	**—**	**—**	**(3.0)**	**—**	**—**	**—**	**(3.0)**
Taxes other than income	**73.6**	**14.7**	**7.0**	**0.3**	**4.1**	**—**	**99.7**
Operating income (loss)	**$ 472.3**	**$ 74.4**	**$ 118.7**	**$ (18.1)**	**$ (0.2)**	**$ (0.4)**	**$ 646.7**
Total assets	**$ 6,620.9**	**$ 1,805.5**	**$ 1,483.8**	**$ 74.5**	**$ 166.6**	**$ (1,245.3)**	**$ 8,906.0**
Capital expenditures (A)	**$ 844.5**	**$ 39.3**	**$ 572.0**	**$ 1.8**	**$ 13.8**	**$ (0.6)**	**$ 1,470.8**

(A) Includes $200.4 million related to the acquisition of certain gas gathering assets as discussed in Note 3.

2010	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
(In millions)							
Operating revenues	$ 2,109.9	$ 403.6	$ 1,005.6	$ 798.5	$ —	$ (600.7)	$ 3,716.9
Cost of goods sold	1,000.2	246.4	733.3	804.7	—	(597.2)	2,187.4
Gross margin on revenues	1,109.7	157.2	272.3	(6.2)	—	(3.5)	1,529.5
Other operation and maintenance	418.1	48.9	91.5	8.4	(13.6)	(3.5)	549.8
Depreciation and amortization	208.7	21.1	50.1	0.1	11.3	—	291.3
Impairment of assets	—	0.7	0.4	—	—	—	1.1
Taxes other than income	69.2	13.9	6.4	0.3	3.6	—	93.4
Operating income (loss)	$ 413.7	$ 72.6	$ 123.9	$ (15.0)	$ (1.3)	$ —	$ 593.9
Total assets	$ 5,898.1	$ 1,246.1	$ 973.8	$ 94.5	$ 135.4	$ (678.8)	$ 7,669.1
Capital expenditures	$ 631.6	$ 70.2	$ 164.0	$ 2.4	$ 14.1	$ (2.4)	$ 879.9

2009	Electric Utility	Transportation and Storage	Gathering and Processing	Marketing	Other Operations	Eliminations	Total
(In millions)							
Operating revenues	$ 1,751.2	$ 401.0	$ 657.5	$ 619.9	$ —	$ (559.9)	$ 2,869.7
Cost of goods sold	796.3	239.9	458.8	617.7	—	(555.0)	1,557.7
Gross margin on revenues	954.9	161.1	198.7	2.2	—	(4.9)	1,312.0
Other operation and maintenance	348.0	40.9	87.2	9.2	(13.9)	(4.6)	466.8
Depreciation and amortization	187.4	20.4	43.9	0.1	10.8	—	262.6
Impairment of assets	0.3	0.9	1.9	—	—	—	3.1
Taxes other than income	65.1	13.2	5.5	0.4	3.4	—	87.6
Operating income (loss)	$ 354.1	$ 85.7	$ 60.2	$ (7.5)	$ (0.3)	$ (0.3)	$ 491.9
Total assets	$ 5,478.1	$ 1,159.5	$ 866.1	$ 125.2	$ 137.3	$ (499.5)	$ 7,266.7
Capital expenditures	$ 600.5	$ 71.4	$ 166.0	$ —	$ 10.2	$ (0.3)	$ 847.8

16. Commitments and Contingencies

Operating Lease Obligations

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

Year ended December 31 *(In millions)*	2012	2013	2014	2015	2016	2017 and Beyond	Total
Operating lease obligations							
OG&E railcars	$ 2.9	$ 2.9	$ 2.8	$ 2.7	$ 27.4	$ —	$ 38.7
Enogex noncancellable operating leases	3.9	3.0	2.4	2.4	2.2	0.6	14.5
Total operating lease obligations	$ 6.8	$ 5.9	$ 5.2	$ 5.1	$ 29.6	$ 0.6	$ 53.2

Payments for operating lease obligations were $9.5 million, $9.4 million and $9.2 million for the years ended December 31, 2011, 2010 and 2009, respectively.

OG&E Railcar Lease Agreement

OG&E has a noncancellable operating lease with purchase options, covering 1,392 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 15, 2010, OG&E renewed the lease agreement effective February 1, 2011. At the end of the new lease term, which is February 1, 2016, 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 fair 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 $22.8 million.

OG&E is also required to maintain all of 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.

Enogex Noncancellable Operating Leases

Enogex currently occupies 116,184 square feet of office space at its executive offices under a lease that expires March 31, 2012. On June 30, 2011, Enogex executed a five-year lease agreement that expires March 31, 2017 for 134,219 square feet of office space at its new executive offices. The lease payments are $11.3 million over the lease term which begins April 1, 2012. Enogex also has compression service and gas treating service agreements which are either on a month-to-month basis or expire during 2012 and 2013.

Other Purchase Obligations and Commitments

The Company's other future purchase obligations and commitments estimated for the next five years are as follows:

(In millions)	2012	2013	2014	2015	2016	Total
Other purchase obligations and commitments						
OG&E cogeneration capacity and fixed operation and maintenance payments	$ 90.3	$ 89.4	$ 87.3	$ 85.2	$ 83.3	$ 435.5
OG&E expected cogeneration energy payments	59.3	68.9	81.3	74.2	86.8	370.5
OG&E minimum fuel purchase commitments	380.2	192.4	87.9	90.4	—	750.9
OG&E expected wind purchase commitments	32.4	32.8	33.3	34.0	34.7	167.2
OG&E long-term service agreement commitments	4.5	6.6	33.7	5.1	5.0	54.9
OER Cheyenne Plains commitments	5.3	6.5	6.5	1.6	—	19.9
OER MEP commitments	2.1	2.1	1.2	—	—	5.4
OER other commitments	4.9	3.1	3.1	3.1	0.7	14.9
Total other purchase obligations and commitments	$ 579.0	$ 401.8	$ 334.3	$ 293.6	$ 210.5	$ 1,819.2

Public Utility Regulatory Policy Act of 1978

At December 31, 2011, OG&E has QF contracts having terms of 15 to 32 years. These contracts were entered into pursuant to the Public Utility Regulatory Policy Act of 1978. Stated generally, the Public Utility Regulatory Policy Act of 1978 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 320 MW AES-Shady Point, Inc. QF contract and the 120 MW PowerSmith Cogeneration Project, L.P. QF contract, OG&E purchases 100 percent of the electricity generated by the QFs.

For the years ended December 31, 2011, 2010 and 2009, OG&E made total payments to cogenerators of $140.7 million, $147.3 million and $139.8 million, respectively, of which $78.0 million, $80.7 million and $83.1 million, respectively, represented capacity payments. All payments for purchased power, including cogeneration, are included in the Consolidated Statements of Income as Cost of Goods Sold.

OG&E Minimum Fuel Purchase Commitments

OG&E purchased necessary fuel supplies of coal and natural gas for its generating units of $647.6 million, $721.4 million and $588.3 million for the years ended December 31, 2011, 2010 and 2009, respectively. OG&E has coal contracts for purchases from January 2012 through December 2015. OG&E has natural gas contracts for purchases from January 2012 through March 2012 that account for 26 percent of OG&E's projected 2012 natural gas requirements. Additional gas supplies to fulfill OG&E's remaining 2012 natural gas requirements will be acquired through additional requests for proposal in early to mid-2012, along with monthly and daily purchases, all of which are expected to be made at market prices.

OG&E Wind Purchase Commitments

OG&E's current wind power portfolio includes: (i) the Centennial wind farm, (ii) the OU Spirit wind farm, (iii) the Crossroads wind farm, (iv) 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 that expires in 2018, (v) access to up to 150 MWs of electricity generated at a wind farm in Woodward County, Oklahoma from a 20-year contract OG&E entered into with CPV Keenan that expires in 2030 and (vi) access to up to 130 MWs of electricity generated at a wind farm in Woodward County, Oklahoma from a 20-year contract OG&E entered into with Edison Mission Energy that expires in 2030.

The following table summarizes OG&E's wind power purchases for the years ended December 31, 2011, 2010 and 2009.

Year ended December 31, 2011 *(In millions)*	**2011**	2010	2009
CPV Keenan	**$ 24.5**	$ 3.8	$ —
Edison Mission Energy	**8.5**	—	—
FPL Energy	**3.7**	3.9	4.0
Total wind power purchased	**$ 36.7**	$ 7.7	$ 4.0

OG&E Long-Term Service Agreement Commitments

In July 2004, OG&E acquired a 77 percent interest in the McClain Plant. As part of that acquisition, OG&E became subject to an existing long-term parts and service maintenance contract for the upkeep of the natural gas-fired combined cycle generation facility. The contract was initiated in December 1999, and runs for the earlier of 96,000 factored-fired hours or 4,800 factored-fired starts. Based on historical usage and current expectations for future usage, this contract is expected to run until 2015. The contract requires payments based on both a fixed and variable cost component, depending on how much the McClain Plant is used.

In September 2008, OG&E acquired a 51 percent interest in the Redbud Plant. As part of that acquisition, OG&E became subject to an existing long-term parts and service maintenance contract for the upkeep of the natural gas-fired combined cycle generation facility. The contract was initiated in January 2001, and runs for the earlier of 120,000 factored-fired hours or 4,500 factored-fired starts. Based on historical usage and current expectations for future usage, this contract is expected to run until 2028. The contract requires payments based on both a fixed and variable cost component, depending on how much the Redbud Plant is used.

OER Agreement with Cheyenne Plains Gas Pipeline Company, L.L.C. (Cheyenne Plains)

In 2004, OER entered into a firm transportation service agreement with Cheyenne Plains, who operates the Cheyenne Plains Pipeline that provides firm transportation services in Wyoming, Colorado and Kansas, for 60,000 decatherms/day of firm capacity on the pipeline. The firm transportation service agreement 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 $7.4 million. Effective March 1, 2007, OER and Cheyenne Plains amended the firm transportation service agreement to provide for OER to turn back 20,000 decatherms/day of its capacity beginning in January 2008 for the remainder of the term.

OER Agreement with MEP

In December 2006, Enogex entered into a firm capacity lease agreement with MEP for a primary term of 10 years (subject to possible extension) that gives 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 2009, OER entered into a firm transportation service agreement with MEP for 10,000 decatherms/day of firm capacity on the pipeline. The firm transportation service agreement was for a five-year term beginning with the in-service date of the MEP pipeline in June 2009 with an annual demand fee of $2.1 million.

Natural Gas Measurement Cases

Will Price, et al. v. El Paso Natural Gas Co., et al. (Price I). On September 24, 1999, various subsidiaries of OGE Energy 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, OG&E and Enogex Inc. were omitted from the case but two of OGE Energy's other subsidiary entities remained as defendants. The plaintiffs' amended petition seeks class certification and alleges that 60 defendants, including two of OGE Energy's subsidiary entities, have improperly measured the volume of natural gas. The 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.

On September 18, 2009, the court entered its order denying class certification. On October 2, 2009, the plaintiffs filed for a rehearing of the court's denial of class certification. On March 31, 2010, the court denied the plaintiffs' request for rehearing. On July 20, 2011, Enogex LLC and OER filed motions for summary judgment. On January 25, 2012, the court denied portions of the motions for summary judgment related to the legal issue of the plaintiffs' claims regarding civil conspiracy. In an order dated January 23, 2012, the court granted the plaintiffs additional time to perform discovery prior to the consideration of the motions for summary judgment as they relate to the plaintiffs' other claims.

OGE Energy intends to vigorously defend this action. At this time, OGE Energy does not believe the outcome will have a material impact on its financial position.

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 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 amended petition of the Price I case. OG&E and Enogex Inc. were not named in this case, but two of OGE Energy's other subsidiary entities were named in this case. The plaintiffs allege that the defendants mismeasured the British thermal unit 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.

On September 18, 2009, the court entered its order denying class certification. On October 2, 2009, the plaintiffs filed for a rehearing of the court's denial of class certification. On March 31, 2010, the court denied the plaintiffs' request for rehearing. On July 20, 2011, Enogex LLC and OER filed motions for summary judgment. On January 25, 2012, the court denied portions of the motions for summary judgment related to the legal issue of the plaintiffs' claims regarding civil conspiracy. In an order dated January 23, 2012, the court granted the plaintiffs additional time to perform discovery prior to the consideration of the motions for summary judgment as they relate to the plaintiffs' other claims.

OGE Energy intends to vigorously defend this action. At this time, OGE Energy does not believe the outcome will have a material impact on its financial position.

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 alleged 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 asserted breach of contract, implied covenants, obligation, fiduciary duty, unjust enrichment, conspiracy and fraud causes of action and claim actual damages, plus attorneys' fees and costs, and punitive damages. 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 Company 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 America, Inc. and BP America Production Company's cross claim on January 16, 2007. On October 14, 2011, this case was dismissed without prejudice. While this lawsuit could be re-filed, Enogex considers the claims and cross claim associated with this lawsuit to be without merit, based upon Enogex's investigation to date. Enogex now considers this case closed.

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 including 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 their wastes, requiring remedial action to mitigate pollution conditions that may be caused by their operations or that are attributable to former operators, regulating future construction activities to mitigate harm to threatened or endangered species and requiring the installation and operation of pollution control equipment. 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. OG&E and Enogex believe that their operations are in substantial compliance with current Federal, state and local environmental standards.

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 is expected to increase the cost of conducting business.

On May 17, 2011, OG&E entered into a Consent Order with the ODEQ related to alleged violations of Federal and state opacity standards from 2005 to May 2011 at OG&E's Muskogee and Sooner generating stations. The Consent Order requires OG&E to reach certain milestones with regard to the overall amount of time when opacity exceeds certain amounts. Beginning January 1, 2015, the Consent Order requires each unit at OG&E's Muskogee and Sooner generating stations to have a rolling annual average of the time that opacity emissions are in excess of 20 percent to a level equal to or below one percent of the total time in a measurement period. OG&E agreed to implement two specific projects and other measures as necessary to achieve the milestones established in the Consent Order. These projects and other measures are not expected to involve significant capital or ongoing operating expenses. OG&E also agreed to pay a stipulated cash penalty of $150,000 and agreed to contribute another $150,000 to an ODEQ environmental fund for assisting small Oklahoma communities with their drinking water and wastewater treatment systems. OG&E entered into the Consent Order without admitting or denying the allegations made by the ODEQ. In order to facilitate the court approval of the Consent Order, the ODEQ initiated the necessary legal action against OG&E in state court on May 17, 2011. On June 2, 2011, the Consent Order was approved and entered by the District Court of Oklahoma County, Oklahoma. Subject to the ongoing compliance obligations described above pursuant to the Consent Order, OG&E considers this matter closed.

OG&E and Enogex are managing several significant uncertainties about the scope and timing for the acquisition, installation and operation of additional pollution control equipment and compliance costs for a variety of the EPA rules that are being challenged in court. OG&E and Enogex are unable to predict the financial impact of these matters with certainty at this time. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Environmental Laws and Regulations" for a discussion of the Company's environmental matters.

Pipeline Safety Legislation

On December 13, 2011, Congress passed the Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011, which the President signed into law on January 3, 2012. Among other things, the law requires additional verification of pipeline infrastructure records by Enogex and other intrastate and interstate pipeline owners and operators to confirm the maximum allowable operating pressure of lines located in high consequence areas or more-densely populated areas. Where records are inadequate to confirm the maximum allowable operating pressure, the PHMSA will require the operator to re-confirm the maximum allowable operating pressure, a process that could cause temporary or permanent limitations on throughput for affected pipelines. This law requires PHMSA to direct pipeline operators to verify the maximum allowable operating pressure of their pipelines by July 3, 2012, and to submit documentation to PHMSA by July 3, 2013. This law also raises the maximum penalty for violating pipeline safety rules to $0.2 million per violation per day up to $2.0 million for a related series of violations.

In addition, this law requires PHMSA to issue reports and/or, if appropriate, develop new regulations, addressing a variety of subjects, including: (1) requiring pipeline owners and operators to install excess-flow valves in certain circumstances; (2) requiring pipeline owners and operators to use automatic or remote-controlled shut-off valves in certain circumstances; (3) requiring pipeline owners and operators to test to confirm the strength of previously untested transmission lines located within high consequence areas and operating at a pressure greater than 30 percent of specified minimum yield stress; (4) requiring pipeline owners and operators to notify the National Response Center of an accident or incident at the earliest practicable moment (but not later than one hour) after confirming that an accident or incident has occurred; (5) expanding integrity management requirements beyond high consequence areas; and (6) applying the Federal pipeline safety regulations to onshore gathering lines that are not currently subject to the Federal pipeline safety regulations. This law prescribes various deadlines for PHMSA to act on these issues.

At this time, the Company is not able to estimate the capital, operating or other costs that may be required to comply with this law and any related PHMSA regulations that may be promulgated, but such costs could be significant.

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 GAAP, an estimate is made of the loss and the appropriate accounting entries are reflected in the Company's Consolidated Financial Statements. Except as otherwise stated above, in Note 17 below and in Item 3 of this Form 10-K, management, after consultation with legal counsel, does not currently anticipate that liabilities arising out of these pending or threatened lawsuits, claims and contingencies will have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

17. Rate Matters and Regulation

Regulation and Rates

OG&E's retail electric tariffs are regulated by the OCC in Oklahoma and by the APSC in Arkansas. The issuance of certain securities by OG&E is also regulated by the OCC and the APSC. OG&E's wholesale electric tariffs, transmission activities, short-term borrowing authorization and accounting practices are subject to the jurisdiction of the FERC. The Secretary of the U.S. Department of Energy has jurisdiction over some of OG&E's facilities and operations. In 2011, 89 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight 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 OGE Energy. The order required that, among other things, (i) OGE Energy permit the OCC access to the books and records of OGE Energy and its affiliates relating to transactions with OG&E, (ii) OGE Energy employ accounting and other procedures and controls to protect against subsidization of non-utility activities by OG&E's customers and (iii) OGE Energy 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 OGE Energy 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

OG&E Wholesale Agreement

On May 28, 2009, OG&E sent a termination notice to the Arkansas Valley Electric Cooperative that OG&E would terminate its wholesale power agreement to all points of delivery where OG&E sells or has sold power to the Arkansas Valley Electric Cooperative, effective November 30, 2011. In December 2010, OG&E and the Arkansas Valley Electric Cooperative entered into a new wholesale power agreement whereby OG&E will supply wholesale power to the Arkansas Valley Electric Cooperative through June 2015. On January 3, 2011, OG&E submitted this agreement to the FERC for approval. The FERC approved the new wholesale power agreement on March 2, 2011 and the new contract was effective May 1, 2011.

OG&E Crossroads Wind Farm

On July 29, 2010, OG&E received an order from the OCC authorizing OG&E to recover from Oklahoma customers the cost to construct Crossroads, with the rider being implemented as the individual turbines are placed in service. The Crossroads wind farm was fully in service in January 2012. As part of this project, on June 16, 2011, OG&E entered into an interconnection agreement with the SPP for Crossroads which allowed Crossroads to interconnect at 227.5 MWs.

OG&E 2010 Arkansas Rate Case Filing

On September 28, 2010, OG&E filed a rate case with the APSC requesting an annual rate increase of $17.7 million, to recover the cost of significant electric system expansions and upgrades, including high-voltage transmission lines, that have been completed since the last rate filing in August 2008, as well as increased operating costs. OG&E also sought recovery, through a rider, of the Arkansas jurisdictional portion of (i) costs associated with transmission upgrades and facilities that have been approved by the SPP in its regional planning processes and constructed by other non-OG&E transmission owners throughout the SPP that have been allocated to OG&E through the FERC-approved transmission rates and (ii) SPP administrative fees. On June 17, 2011, the APSC approved a settlement agreement among all parties to the case and OG&E implemented new electric rates effective June 20, 2011. Key items of the APSC order include: (i) the recovery of and a return on significant electric system expansions and upgrades, including high-voltage transmission lines, as well as increased operating costs, totaling $8.8 million annually; (ii) authorization for OG&E to recover the actual cost of third-party transmission charges and SPP administrative fees through a rider mechanism which will remain in effect until new rates are implemented after OG&E's next general rate case (the Arkansas jurisdictional portion of the combined costs was $1.0 million in 2011); and (iii) the deferral of certain expenses associated with a customer education program in an amount not to exceed $0.3 million per year for a maximum of two years.

OG&E SPP Cost Tracker

On October 7, 2010, OG&E filed an application with the OCC seeking recovery of the Oklahoma jurisdictional portion of (i) costs associated with transmission upgrades and facilities that have been approved by the SPP in its regional planning processes and constructed by other non-OG&E transmission owners throughout the SPP that have been allocated to OG&E through the FERC-approved transmission rates and (ii) SPP administrative fees. OG&E requested authorization to implement a cost tracker in order to recover from its retail customers the third-party project costs discussed above and to collect its administrative SPP cost assessment levied under Schedule 1A of the SPP open access transmission tariff, which is currently recovered in base rates. OG&E also requested authorization to establish a regulatory asset effective January 1, 2011 in order to give OG&E the opportunity to recover such costs that will be paid but not recovered until the cost tracker is made effective. On February 8, 2011, all parties signed a settlement agreement in this matter which would allow OG&E to recover the costs discussed in (i) above through a recovery rider effective January 1, 2011. OG&E recovered $5.1 million of incremental revenues in 2011 through the rider. Rather than including the costs of the SPP administrative fee assessment in the recovery rider, the stipulating parties agreed to allow OG&E to include the projected 2012 level of the SPP administrative fee assessment in its next Oklahoma rate case which was filed in August 2011. Pursuant to the settlement agreement in OG&E's 2011 Oklahoma general rate case filing, OG&E proposed that recovery in base rates for the costs of transmission projects it constructs and owns and that are authorized by the SPP in its regional planning processes should be limited to the Oklahoma retail jurisdictional share of the costs for such projects allocated to OG&E by the SPP. On March 28, 2011, the OCC issued an order in this matter approving the settlement agreement.

OG&E Fuel Adjustment Clause Review for Calendar Year 2009

On October 29, 2010, the OCC Staff filed an application for a public hearing to review and monitor OG&E's application of the 2009 fuel adjustment clause. On December 28, 2010, OG&E responded by filing the necessary information and documents to satisfy the OCC's minimum filing requirement rules. An intervenor representing a group of OG&E's industrial customers filed testimony on March 11, 2011 seeking a $15.5 million refund related to (i) a purported failure by OG&E to maximize the use of its coal-fired power plants and (ii) an inappropriate extension of the existing gas transportation and storage contract between OG&E and Enogex. OG&E filed rebuttal testimony on April 4, 2011 in opposition to the claims of the intervenor. On August 11, 2011, all parties to this case signed a settlement agreement in this matter, stating that (i) OG&E was prudent in its operations during 2009; (ii) a third party expert should be hired to evaluate OG&E's future gas transportation and storage needs and that OG&E should file a plan for meeting its future gas transportation and storage needs by mid-2012; and (iii) with respect to the existing gas transportation and storage contract with Enogex, OG&E will return $8.4 million to its customers in settlement for all periods under the contract through April 30, 2013. In August 2011, OG&E credited $4.9 million to its customers and will credit the remaining amount on a monthly basis through April 30, 2013. The OCC issued an order approving the settlement agreement on August 29, 2011.

OG&E Smart Grid Project

On December 17, 2010, OG&E filed an application with the APSC requesting pre-approval for system-wide deployment of smart grid technology and a recovery rider, including a credit for the Smart Grid grant awarded by the U.S. Department of Energy under the American Recovery and Reinvestment Act of 2009. On June 22, 2011, OG&E reached a settlement agreement with all the parties in this matter. OG&E and the other parties in this matter agreed to ask the APSC to approve the settlement agreement including the following: (i) pre-approval of system-wide deployment of smart grid technology in Arkansas and authorization for OG&E to begin recovering the prudently incurred costs of the Arkansas system-wide deployment of smart grid technology through a rider mechanism that will become effective in accordance with the order approving the settlement agreement; (ii) cost recovery through the rider would commence when all of the smart meters to be deployed in Arkansas are in service; (iii) OG&E guarantees that customers will receive certain operations and maintenance cost reductions resulting from the smart grid deployment as a credit to the recovery rider; and (iv) the stranded costs associated with OG&E's existing meters which are being replaced by smart meters will be accumulated in a regulatory asset and recovered in base rates beginning after an order is issued in OG&E's next general rate case. OG&E currently expects to spend $14 million, net of funds from the U.S. Department of Energy grant, in capital expenditures to implement smart grid in Arkansas pursuant to the settlement agreement. On August 3, 2011, the APSC issued an order in this matter approving the settlement agreement.

OG&E FERC Transmission Rate Incentive Filing

On February 18, 2011, OG&E submitted to the FERC a request seeking limited transmission rate incentives for five transmission projects. OG&E requested recovery of 100 percent of all prudently incurred construction work in progress in rate base for five 345 kilovolt Extra High Voltage transmission projects to be constructed and owned by OG&E within the SPP's region. OG&E also requested to recover 100 percent of all prudently incurred development and construction costs if the transmission projects are abandoned or cancelled, in whole or in part, for reasons beyond OG&E's control. On April 19, 2011, the FERC granted these incentives for the Sooner-Rose Hill, Sunnyside-Hugo and Balanced Portfolio 3E transmission projects discussed below.

OG&E Pension Tracker Modification Filing

On February 22, 2011, OG&E filed an application with the OCC requesting that OG&E's pension tracker be modified to include the difference between the level of retiree medical costs authorized in OG&E's last rate case and the current level of these expenses as a regulatory liability, effective January 1, 2011. On June 23, 2011, a settlement agreement was filed by parties in the case stating that the pension tracker should be modified as proposed by OG&E and that the level of retiree medical costs included in base rates will be reviewed and determined in OG&E's next rate case. On September 27, 2011, the OCC issued an order in this matter approving the settlement agreement.

OG&E Demand and Energy Efficiency Program Filing

To build on the success of its earlier programs and further promote energy efficiency and conservation for each class of OG&E customers, on March 15, 2011, OG&E filed an application with the APSC seeking approval of several programs, ranging from residential weatherization to commercial lighting. In seeking approval of these programs, OG&E also sought recovery of the program and related costs through a rider that would be added to customers' electric bills. On June 30, 2011, the APSC issued an order approving OG&E's energy efficiency plan for 2011 and approving OG&E's energy efficiency cost recovery rider for 2011. In Arkansas, OG&E's program is expected to cost $7.0 million over a three-year period and is expected to increase the average residential electric bill by $1.47 per month.

FERC Order No. 1000, Final Rule on Transmission Planning and Cost Allocation

On July 21, 2011, the FERC issued Order No. 1000, which revised the FERC's existing regulations governing the process for planning enhancements and expansions of the electric transmission grid in a particular region, along with the corresponding process for allocating the costs of such expansions. Order No. 1000 applies only to "new transmission facilities," which are described as those subject to evaluation or reevaluation (under the applicable local or regional transmission planning process) subsequent to the effective date of the regulatory compliance filings required by the rule, which are expected to be filed during the third quarter of 2012. Order No. 1000 leaves to individual regions to determine whether a previously-approved project is subject to reevaluation and is therefore governed by the new rule.

Order No. 1000 requires, among other things, public utility transmission providers, such as the SPP, to participate in a process that produces a regional transmission plan satisfying certain standards, and requires that each such regional process consider transmission needs driven by public policy requirements (such as state or Federal policies favoring increased use of renewable energy resources). Order No. 1000 also directs public utility transmission providers to coordinate with neighboring transmission planning regions. In addition, Order No. 1000 establishes specific regional cost allocation principles and directs public utility transmission providers to participate in regional and interregional transmission planning processes that satisfy these principles.

On the issue of determining how entities are to be selected to develop and construct the specific transmission projects, Order No. 1000 directs public utility transmission providers to remove from the FERC-jurisdictional tariffs and agreements provisions that establish any federal "right of first refusal" for the incumbent transmission owner (such as OG&E) regarding transmission facilities selected in a regional transmission planning process, subject to certain limitations. However, Order No. 1000 is not intended to affect the right of an incumbent transmission owner (such as OG&E) to build, own and recover costs for upgrades to its own transmission facilities, and Order No. 1000 does not alter an incumbent transmission owner's use and control of existing rights of way. Order No. 1000 also clarifies that incumbent transmission owners may rely on regional transmission facilities to meet their reliability needs or service obligations. The SPP currently has a "right of first refusal" for incumbent transmission owners and this provision has played a role in OG&E being selected by the SPP to build various transmission projects in Oklahoma.

OGE Energy is continuing to evaluate Order No. 1000 and cannot at this time determine its precise impact on OG&E. Nevertheless, at the present time, OGE Energy has no reason to believe that the implementation of Order No. 1000 will impact OG&E's transmission projects currently under development and construction for which OG&E has received a notice to proceed from the SPP.

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 Section 311 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. Enogex did not place the increased rates set forth in its October 2007 rate filing into effect but rather continued to provide interruptible Section 311 service under the maximum Section 311 rates for both zones approved by the FERC in the previous rate case. A final settlement was filed with the FERC on August 5, 2010. With the filing of Enogex's Section 311 2009 rate case discussed below, the rate period for the 2007 rate case became a limited locked-in period from January 2008 through May 2009. On October 13, 2011, the FERC issued an order in this matter approving the settlement agreement, providing that Enogex's rates from its previous rate case remain in effect and that the MEP lease agreement discussed below would be addressed in Enogex's Section 311 2009 rate case. This matter is now closed.

Enogex FERC Section 311 2009 Rate Case

On March 27, 2009, Enogex filed a petition for rate approval with the FERC to set the maximum rates for its new firm East Zone Section 311 transportation service and to revise the rates for its existing East and West Zone interruptible Section 311 transportation service. In anticipation of offering this new service, Enogex had filed with the FERC, as required by the FERC's regulations, a revised Statement of Operating Conditions Applicable to Transportation Services to describe the terms, conditions and operating arrangements for the new service. Enogex made the Statement of Operating Conditions filing on February 27, 2009. Enogex began offering firm East Zone Section 311 transportation service on April 1, 2009. The revised East and West Zone zonal rates for the Section 311 interruptible transportation service became effective June 1, 2009. The rates for the firm East Zone Section 311 transportation service and the increase in the rates for East and West Zone and interruptible Section 311 service were collected, subject to refund, pending the FERC approval of the proposed rates. A number of parties intervened in both the rate case and the Statement of Operating Conditions filing and some additionally filed protests. On January 4, 2010, the FERC Staff submitted an offer proposing various adjustments to Enogex's filed cost of service. On April 27, 2010, Enogex submitted comments to the FERC Staff stating that it would agree to the offer, contingent upon all parties agreeing to support or not oppose. On October 4, 2011, Enogex filed a settlement agreement with the FERC which included a proposed refund to shippers of $2.1 million related to the increase in the rates for East and West Zone and interruptible Section 311 service which were collected, subject to refund, pending the FERC approval of the proposed rates. This refund was made to shippers in January 2012. On December 16, 2011, the FERC issued an order approving the settlement agreement. Also, as discussed below, the MEP lease agreement was addressed in this rate case.

On November 13, 2007, one of the protesting intervenors filed to consolidate the Enogex 2007 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 MEP pipeline and to lease firm capacity from Enogex. Enogex and MEP separately opposed this intervenor's protests and assertions in its initial and subsequent pleadings. On July 25, 2008, the FERC issued an order (i) approving the MEP project including the approval of a limited jurisdiction certificate and (ii) authorizing the Enogex lease agreement with MEP. Accordingly, Enogex proceeded with the construction of facilities necessary to implement this service. On August 25, 2008, a protestor sought rehearing which the FERC denied. Enogex commenced service to MEP under the lease agreement on June 1, 2009. On July 16, 2009, the protestor filed, with the United States Court of Appeals for the District of Columbia Circuit, a petition for review of the FERC's orders approving the MEP construction and the MEP lease of capacity from Enogex requesting that such orders be modified or set aside on the grounds that they are arbitrary, capricious and contrary to law. On December 28, 2010, the Court of Appeals issued an opinion generally upholding the FERC's orders, but remanding the case for further explanation of one aspect of the FERC's reasoning. The Court of Appeals emphasized that it was not vacating the FERC's orders and that its approval of the Enogex lease agreement with MEP remains in effect and legally binding. On remand, the FERC was to clarify that its decision was based on a finding that the lease does not adversely affect existing customers on Enogex's system. On January 21, 2011, Apache Corporation filed a motion asking the FERC to establish procedures on remand and to either condition the lease on Enogex's willingness to provide firm Section 311 transportation service to existing customers on all portions of its system or to establish an expedited briefing schedule. On February 7, 2011, Enogex, MEP and Chesapeake Energy Corporation filed a joint answer asking the FERC to find, among other things, that the reduction in the amount of interruptible transportation capacity available due to the MEP lease did not have an adverse affect on Apache Corporation and to acknowledge that Apache Corporation's request to condition the lease on the provision of West Zone 311 firm transportation service has been addressed as Enogex filed a rate case on January 28, 2011 proposing to implement such service effective March 1, 2011. On March 1, 2011, Apache Corporation filed an answer seeking to refute some of the arguments presented in the joint answer filed by Enogex, MEP and Chesapeake Energy Corporation. On March 3, 2011, the FERC issued an order on remand affirming the authorizations previously granted to Enogex and MEP and clarifying the applicable legal standard in response to the court's directive. On April 4, 2011, Apache Corporation filed a request for rehearing of the FERC's order on remand. On September 29, 2011, the FERC issued an order denying Apache Corporation's motion for rehearing. Apache Corporation did not appeal the FERC's March 3, 2011 order on remand and/or the September 29, 2011 order denying rehearing. This matter is now closed.

Pending Regulatory Matters

OG&E 2011 Oklahoma Rate Case Filing

As part of the Joint Stipulation and Settlement Agreement reached in OG&E's 2009 Oklahoma rate case filing, the parties agreed that OG&E would file a rate case on or before June 30, 2011. On May 27, 2011, OG&E requested an extension until the end of July 2011 for filing the Oklahoma rate case. On July 28, 2011, OG&E filed its application with the OCC requesting an annual rate increase of $73.3 million, or a 4.3 percent increase in its rates. OG&E is requesting a return on equity of 11.00 percent based on a common equity percentage of 53 percent. Each 0.10 percent change in the requested return on equity affects the requested rate increase by $3.0 million. In its application, OG&E seeks to recover increases in its operating costs and to begin earning on approximately $500 million of new capital investments made on behalf of its Oklahoma customers during the previous two and one-half years. On November 9, 2011, the OCC Staff recommended a $6.2 million annual rate decrease based on a return on equity of 9.81 percent and a common equity percentage of 53 percent. The staff of the Oklahoma Attorney General recommended a return on equity of 9.818 percent and a common equity percentage of 49.5 percent. The staff of the Oklahoma Attorney General did not recommend a specific revenue requirement, but OG&E believes that adoption of the staff of the Oklahoma Attorney General's recommendations would result in a rate decrease. The Oklahoma Industrial Electric Consumers recommended a $56 million annual rate decrease based on a return on equity of 9.5 percent and a common equity percentage of 48 percent. OG&E filed rebuttal testimony on November 29, 2011 on the revenue requirement testimony filed by the parties on November 9, 2011. On November 16, 2011, the parties filed cost-of-service and rate design testimony and OG&E filed rebuttal testimony in those areas on December 2, 2011. The hearing in this matter began on December 13, 2011. OG&E expects to receive an order from the OCC in the first quarter of 2012.

OG&E Fuel Adjustment Clause Review for Calendar Year 2010

On August 19, 2011, the OCC Staff filed an application for a public hearing to review and monitor OG&E's application of the 2010 fuel adjustment clause. On October 18, 2011, OG&E responded by filing the necessary information and documents to satisfy the OCC's minimum filing requirement rules. A procedural schedule has not yet been established in this matter.

OG&E Contract and Wind Energy Purchase Agreement Filing

On December 1, 2011, OG&E filed an application with the OCC requesting approval of a 20-year agreement that is intended to provide wind power to help meet the current and future power generation needs of Oklahoma State University. The project calls for OG&E to contract with NextEra Energy to build a 60 MW wind farm near Blackwell, Oklahoma, to support the Oklahoma State University project in which NextEra will build, own and operate the wind farm and OG&E will purchase the electric output. A procedural schedule has not yet been established in this matter. OG&E expects to receive a decision from the OCC in the first quarter of 2012.

SPP Transmission/Substation Projects

The SPP is a regional transmission organization under the jurisdiction of the FERC that was created to ensure reliable supplies of power, adequate transmission infrastructure and competitive wholesale prices of electricity. The SPP does not build transmission though the SPP's tariff contains rules that govern the transmission construction process. Transmission owners complete the construction and then own, operate and maintain transmission assets within the SPP region. When the SPP Board of Directors approves a project, the transmission provider in the area where the project is needed currently has the first obligation to build; however, the process for deciding which entity constructs and owns a project may change as a result of FERC Order. No. 1000 discussed above.

There are several studies currently under review at the SPP including a 20-year plan to address issues of regional and interregional importance. The 20-year plan suggests overlaying the SPP footprint with a 345 kilovolt transmission system and integrating it with neighboring regional entities. In 2009, the SPP Board of Directors approved a new report that recommended restructuring the SPP's regional planning processes to focus on the construction of a robust transmission system, large enough in both scale and geography, to provide flexibility to meet the SPP's future needs. OG&E expects to actively participate in the ongoing study, development and transmission growth that may result from the SPP's plans.

In 2007, the SPP notified OG&E to construct 44 miles of a new 345 kilovolt transmission line which will originate at OG&E's existing Sooner 345 kilovolt substation and proceed generally in a northerly direction to the Oklahoma/Kansas Stateline (referred to as the Sooner-Rose Hill project). At the Oklahoma/Kansas Stateline, the line will connect to the companion line being constructed in Kansas by Westar Energy. Construction of the line began in early 2011 and the line is estimated to be in service by mid-2012 at an estimated cost of $45 million for OG&E.

In January 2009, OG&E received notification from the SPP to begin construction on 50 miles of a new 345 kilovolt transmission line and substation upgrades at OG&E's Sunnyside substation, among other projects. In April 2009, Western Farmers Electric Cooperative assigned to OG&E the construction of 50 miles of line designated by the SPP to be built by Western Farmers Electric Cooperative. The new line will extend from OG&E's Sunnyside substation near Ardmore, Oklahoma, 123.5 miles to the Hugo substation owned by Western Farmers Electric Cooperative near Hugo, Oklahoma. The project cost is estimated at $155 million for OG&E. OG&E began preliminary line routing and acquisition of rights-of-way in June 2009. Construction began in January 2011. When construction is completed, which is expected in mid-2012, the SPP will allocate a portion of the annual revenue requirement to OG&E customers according to the regional cost allocation mechanism as provided in the SPP tariff for application to such improvements.

On April 28, 2009, the SPP approved the Balanced Portfolio 3E projects. Balanced Portfolio 3E includes four projects to be built by OG&E and includes: (i) construction of 135 miles of transmission line from OG&E's Seminole substation in a northeastern direction to OG&E's Muskogee substation at an estimated cost of $160 million for OG&E, which is expected to be in service by late 2013, (ii) construction of 96 miles of transmission line from OG&E's Woodward District Extra High Voltage substation in a southwestern direction to the Oklahoma/Texas Stateline to a companion transmission line to be built by Southwestern Public Service to its Tuco substation at an estimated cost of $145 million for OG&E, which is expected to be in service by mid-2014, (iii) construction of 39 miles of transmission line from OG&E's Sooner substation in an eastern direction to the Grand River Dam Authority Cleveland substation at an estimated cost of $60 million for OG&E, which is expected to be in service by late 2012 and (iv) construction of a new substation near Anadarko which consisted of a 345/138 kilovolt transformer and substation breakers and was built in OG&E's portion of the Cimarron-Lawton East Side 345 kilovolt line at an estimated cost of $15 million for OG&E, which was placed in service in December 2011. On June 19, 2009, OG&E received a notice to construct the Balanced Portfolio 3E projects from the SPP. On July 23, 2009, OG&E responded to the SPP that OG&E will construct the Balanced Portfolio 3E projects discussed above beginning in early 2011.

On April 27, 2010, the SPP approved, contingent upon approval by the FERC of a regional cost allocation methodology filed with the FERC by the SPP, a set of transmission projects titled "Priority Projects." The Priority Projects consist of several transmission projects, two of which have been assigned to OG&E. The 345 kilovolt projects include: (i) construction of 99 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to a companion transmission line to be built by Southwestern Public Service to its Hitchland substation in the Texas Panhandle at an estimated cost of $185 million for OG&E, which is expected to be in service by mid-2014 and (ii) construction of 77 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to a companion transmission line at the Kansas border to be built by either Mid-Kansas Electric Company or another company assigned by Mid-Kansas Electric Company at an estimated cost of $150 million to OG&E, which is expected to be in service by late 2014. On June 17, 2010, the FERC approved the cost allocation filed by the SPP and notices to construct these Priority Projects were issued by the SPP on June 30, 2010. On September 27, 2010, OG&E responded to the SPP that OG&E will construct the Priority Projects discussed above beginning in June 2012. The scope of the Woodward District Extra High Voltage substation/Kansas border Priority Project was subsequently revised and the SPP Board of Directors approved this revision in October 2010. The SPP issued a revised notice to construct for this Priority Project on November 22, 2010. On February 4, 2011, OG&E responded to the SPP that OG&E will construct the revised Priority Project.

The capital expenditures related to the Sooner-Rose Hill, Sunnyside-Hugo, Balanced Portfolio 3E and Priority Projects are presented in the summary of capital expenditures for known and committed projects in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Future Capital Requirements and Financing Activities."

Enogex Storage Statement of Operating Conditions Filing

On August 31, 2010, Enogex filed via eTariff with the FERC a new Statement of Operating Conditions applicable to storage services that replaced Enogex's existing storage Statement of Operating Conditions effective July 30, 2010. Among other things, the new storage Statement of Operating Conditions updates the general terms and conditions for providing storage services. A FERC order is pending.

Enogex FERC Section 311 2011 Rate Case

On January 28, 2011, Enogex submitted a new rate filing to the FERC to set the maximum rate for a new firm Section 311 transportation service in the West Zone of its system and to revise the currently effective maximum rates for Section 311 interruptible transportation service in the East Zone and West Zone. Along with establishing the rate for a new firm service in the West Zone, Enogex's filing requested a decrease in the maximum interruptible zonal rates in the West Zone and to retain the currently effective rates for firm and interruptible services in the East Zone. Enogex reserved the right to implement the higher rates for firm and interruptible services in the East Zone supported by the cost of service to the extent an expeditious settlement agreement cannot be reached in the proceeding. Enogex proposed that the rates be placed into effect on March 1, 2011. The deadline for interventions and protests on Enogex's filing was November 28, 2011 and no protests were filed. On January 10, 2012, Enogex filed a settlement agreement with the FERC. The deadline for comments to the filing was January 17, 2012, and no comments opposing the settlement were filed. A FERC order is pending.

Enogex 2011 Fuel Filing

On February 28, 2011, Enogex submitted its annual fuel filing to establish the fixed fuel percentages for its East Zone and West Zone for the upcoming fuel year (April 1, 2011 through March 31, 2012). Along with the revised fuel percentages, Enogex also requested authority to revise its Statement of Operating Conditions to permanently change the annual filing date to February 28. The deadline for interventions and protests on Enogex's filing was March 15, 2011, and no protests were filed. A FERC order is pending.

18. Quarterly Financial Data (Unaudited)

Due to the seasonal fluctuations and other factors of the Company's businesses, the operating results for interim periods are not necessarily indicative of the results that may be expected for the year. In the Company's opinion, the following quarterly financial data includes all adjustments, consisting of normal recurring adjustments, necessary to fairly present such amounts. Summarized consolidated quarterly unaudited financial data is as follows:

Quarter ended (*In millions, except per share data)*		March 31	June 30	September 30	December 31	Total
Operating revenues	**2011**	**$ 840.5**	**$ 978.1**	**$ 1,212.1**	**$ 885.2**	**$ 3,915.9**
	2010	$ 875.8	$ 887.2	$ 1,125.4	$ 828.5	$ 3,716.9
Operating income	**2011**	**$ 67.9**	**$ 182.2**	**$ 299.7**	**$ 96.9**	**$ 646.7**
	2010	$ 86.8	$ 151.5	$ 274.2	$ 81.4	$ 593.9
Net income	**2011**	**$ 29.7**	**$ 109.3**	**$ 181.4**	**$ 43.2**	**$ 363.6**
	2010	$ 25.2	$ 77.9	$ 163.5	$ 33.8	$ 300.4
Net income attributable to OGE Energy	**2011**	**$ 24.8**	**$ 103.0**	**$ 178.7**	**$ 36.4**	**$ 342.9**
	2010	$ 24.2	$ 77.3	$ 163.1	$ 30.7	$ 295.3
Basic earnings per average common share attributable to OGE Energy common shareholders (A)	**2011**	**$ 0.25**	**$ 1.05**	**$ 1.82**	**$ 0.37**	**$ 3.50**
	2010	$ 0.25	$ 0.79	$ 1.67	$ 0.32	$ 3.03
Diluted earnings per average common share attributable to OGE Energy common shareholders (A)	**2011**	**$ 0.25**	**$ 1.04**	**$ 1.80**	**$ 0.37**	**$ 3.45**
	2010	$ 0.25	$ 0.78	$ 1.65	$ 0.31	$ 2.99

(A) Due to the impact of dilution on the earnings per share calculation, quarterly earnings per share amounts may not add to the total.

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, 2011 and 2010, and the related consolidated statements of income, changes in stockholders' equity, comprehensive income and cash flows for each of the three years in the period ended December 31, 2011. 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, 2011 and 2010, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2011, 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, 2011, 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 16, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 16, 2012

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

None.

Item 9A. Controls and Procedures.

The Company maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. 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 and chief financial officer, 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 chief executive officer and chief financial officer, 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 chief executive officer and chief financial officer 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 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, 2011. 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, 2011, the Company's internal control over financial reporting is effective based on those criteria.

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

/s/ Peter B. Delaney	/s/ Scott Forbes
Peter B. Delaney, Chairman of the Board, President and Chief Executive Officer	Scott Forbes, Controller and Chief Accounting Officer
/s/ Sean Trauschke	
Sean Trauschke, Vice President and 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, 2011, 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 the 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, 2011, 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, 2011 and 2010, and the related consolidated statements of income, changes in stockholders' equity, comprehensive income and cash flows for each of the three years in the period ended December 31, 2011 of OGE Energy Corp. and our report dated February 16, 2012 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 16, 2012

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Code of Ethics Policy

OGE Energy 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 OGE Energy's web site address www.oge.com under the heading "Investor Relations", "Corporate Governance." The code of ethics will be provided, free of charge, upon request. OGE Energy 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. OGE Energy will also include in its proxy statement information regarding the Audit Committee financial experts.

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 Securities and Exchange Commission on or about March 31, 2012. Such proxy statement is incorporated herein by reference.

PART IV

Item 15. Exhibits and Financial Statement Schedules.

(a) 1. Financial Statements

The following Consolidated Financial Statements are included in Part II, Item 8 of this Annual Report:

- Consolidated Statements of Income for the years ended December 31, 2011, 2010 and 2009
- Consolidated Statements of Comprehensive Income for the years ended December 31, 2011, 2010 and 2009
- Consolidated Statements of Cash Flows for the years ended December 31, 2011, 2010 and 2009
- Consolidated Balance Sheets at December 31, 2011 and 2010
- Consolidated Statements of Capitalization at December 31, 2011 and 2010
- Consolidated Statements of Changes in Stockholders' Equity for the years ended December 31, 2011, 2010 and 2009
- 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)

2. Financial Statement Schedule (included in Part IV)

- Schedule II - Valuation and Qualifying Accounts

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.

Table of Contents

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	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)
2.14	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)
2.15	Investment Agreement dated as of October 5, 2010 by and between OGE Energy Corp., Enogex Holdings LLC and Bronco Midstream Holdings, 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 October 6, 2010 (File No. 1-12579) and incorporated by reference herein)
3.01	Copy of Restated OGE Energy Corp. Certificate of Incorporation. (Filed as Exhibit 3.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12579) and incorporated by reference herein)
3.02	Copy of Amended OGE Energy Corp. By-laws. (Filed as Exhibit 3.02 to OGE Energy's Form 10-Q for the quarter ended June 30, 2010 (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 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)
4.14	Issuing and Paying Agency Agreement dated as of June 15, 2009, by and between Enogex LLC and UMB Bank, N.A. (Filed as Exhibit 4.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2009 (File No. 1-12579) and incorporated by reference herein)
4.15	Issuing and Paying Agency Agreement dated as of November 15, 2009, by and between Enogex LLC and UMB Bank, N.A. (Filed as Exhibit 4.15 to OGE Energy's Form 10-K for the year ended December 31, 2009 (File No. 1-12579) and incorporated by reference herein)
4.16	Supplemental Indenture No. 11 dated as of June 1, 2010 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed June 8, 2010 (File No. 1-1097) and incorporated by reference herein)
4.17	Supplemental Indenture No. 12 dated as of May 15, 2011 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed May 27, 2011 (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 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 8-K filed July 6, 2009 (File No. 1-12579) and incorporated by reference herein)
10.05	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)

10.06	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)
10.07	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)
10.08*	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)
10.09	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)
10.10	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)
10.11*	Form of Performance Unit Agreement under 2008 Stock Incentive Plan. (Filed as Exhibit 10.02 to OGE Energy's Form 10-Q for the quarter ended March 31, 2010 (File No. 1-12579) and incorporated by reference herein)
10.12*	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)
10.13	Credit agreement dated as of December 13, 2011, by and between OGE Energy, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Corporate Bank, Ltd., The Royal Bank of Scotland PLC, UBS Securities LLC and Union Bank, N.A., as Co-Documentation Agents. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed December 19, 2011 (File No. 1-12579) and incorporated by reference herein)
10.14	Credit agreement dated as of December 13, 2011, by and between OG&E, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Corporate Bank, Ltd., The Royal Bank of Scotland PLC, UBS Securities LLC and Union Bank, N.A., as Co-Documentation Agents. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed December 19, 2011 (File No. 1-12579) and incorporated by reference herein)
10.15*	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)
10.16*	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)
10.17	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)
10.18	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)
10.19	Credit agreement dated as of December 13, 2011, by and between Enogex LLC, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Corporate Bank, Ltd., The Royal Bank of Scotland PLC, UBS Securities LLC and Union Bank, N.A., as Co-Documentation Agents. (Filed as Exhibit 99.03 to OGE Energy's Form 8-K filed December 19, 2011 (File No. 1-12579) and incorporated by reference herein)
10.20*	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)
10.21*	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)
10.22*	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)
10.23*	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)
10.24*	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)
10.25*	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)

10.26*	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)
10.27*	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)
10.28*	Form of Employment Agreement for all existing and future officers of the Company relating to change of control.
10.29*	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)
10.30	Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's OU Spirit application. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed December 2, 2009 (File No. 1-12579) and incorporated by reference herein)
10.31	Agreement, dated February 17, 2010, between Oklahoma Gas and Electric Company and Oklahoma Department of Environmental Quality. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed February 23, 2010 (File No. 1-12579) and incorporated by reference herein)
10.32*	Amendment No. 1 to the Company's Restoration of Retirement Income Plan. (Filed as Exhibit 10.40 to OGE Energy's Form 10-K for the year ended December 31, 2009 (File No. 1-12579) and incorporated by reference herein)
10.33*	Amendment No. 1 to the Company's Deferred Compensation Plan.
10.34	Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Smart Grid application. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed June 1, 2010 (File No. 1-12579) and incorporated by reference herein)
10.35	Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Crossroads application. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed July 1, 2010 (File No. 1-12579) and incorporated by reference herein)
10.36	Copy of Settlement Agreement 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 May 19, 2011 (File No. 1-12579) and incorporated by reference herein)
10.37	Copy of Settlement Agreement with Arkansas Public Service Commission Staff, the Arkansas Attorney General and others relating to OG&E's Smart Grid application. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed June 28, 2011 (File No. 1-12579) and incorporated by reference herein)
10.38*	Amendment No. 2 to the Company's Deferred Compensation Plan. (Filed as Exhibit 10.41 to OGE Energy's Form 10-K for the year ended December 31, 2009 (File No. 1-12579) and incorporated by reference herein)
10.39*	Amendment No. 3 to the Company's Deferred Compensation Plan.
10.40*	Amendment No. 1 to the Company's 2008 Stock Incentive Plan.
10.41*	Directors' Compensation.
10.42*	Executive Officer Compensation.
10.43*	Consulting Agreement between the Company and Danny P. Harris, the Company's retired Chief Operating Officer.
12.01	Calculation of Ratio of Earnings to Fixed Charges.
21.01	Subsidiaries of the Registrant.
23.01	Consent of Ernst & Young LLP.
24.01	Power of Attorney.
31.01	Certifications Pursuant to Rule 13a-14(a)/15d-14(a) 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 July 30, 2009 (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 99.02 to OGE Energy's Form 8-K filed June 22, 2011 (File No. 1-12579) and incorporated by reference herein)
99.04	Copy of OCC order with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's OU Spirit application. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed October 21, 2009 (File No. 1-12579) and incorporated by reference herein)

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99.05	Copy of OCC Order with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Smart Grid application. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed July 7, 2010 (File No. 1-12579) and incorporated by reference herein)
99.06	Copy of OCC Order with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Crossroads application. (Filed as Exhibit 99.04 to OGE Energy's Form 10-Q for the quarter ended June 30, 2010 (File No. 1-12579) and incorporated by reference herein)
99.07	Description of Capital Stock. (Filed as Exhibit 99.07 to OGE Energy's Form 10-K for the year ended December 31, 2010 (File No. 1-12579) and incorporated by reference herein)
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Schema Document.
101.PRE	XBRL Taxonomy Presentation Linkbase Document.
101.LAB	XBRL Taxonomy Label Linkbase Document.
101.CAL	XBRL Taxonomy Calculation Linkbase Document.
101.DEF	XBRL Definition Linkbase Document.

* 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	Deductions (A)	Balance at End of Period
(In millions)				
Balance at December 31, 2009				
Reserve for Uncollectible Accounts	$ 3.2	$ 3.1	$ 3.9	$ 2.4
Balance at December 31, 2010				
Reserve for Uncollectible Accounts	$ 2.4	$ 2.6	$ 3.1	$ 1.9
Balance at December 31, 2011				
Reserve for Uncollectible Accounts	$ 1.9	$ 5.8	$ 3.9	$ 3.8

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

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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 16th day of February, 2012.

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 16, 2012
/s/ Sean Trauschke Sean Trauschke	Principal Financial Officer; and	February 16, 2012
/s/ Scott Forbes Scott Forbes	Principal Accounting Officer.	February 16, 2012
James H. Brandi	Director;	
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;	
Judy R. McReynolds	Director; and	
Leroy C. Richie	Director.	
/s/ Peter B. Delaney By Peter B. Delaney (attorney-in-fact)		February 16, 2012

Exhibit 10.28

OGE Energy Corp.
Form of Employment Agreement

AGREEMENT by and between OGE Energy Corp., an Oklahoma corporation, and _______________ (the "Executive"), dated as of the __ day of ___________.

WHEREAS, the Board of Directors (the "Board") of the Company (as hereinafter defined) recognizes that the possibility of a Change of Control (as hereinafter defined) exists and that the occurrence of a Change of Control can result in significant distractions of its key management personnel because of the uncertainties inherent in such a situation;

WHEREAS, the Board has determined that it is essential and in the best interest of the Company and its shareowners to retain the services of the Executive in the event of a Change of Control and to ensure the Executive's continued dedication and efforts in such event without undue concern for the Executive's personal financial and employment security; and

WHEREAS, in order to induce the Executive to remain in the employ of the Company or an Affiliate (as hereinafter defined), as the case may be, particularly in the event of a threat or the occurrence of a Change of Control, the Company desires to enter into this Employment Agreement with the Executive to provide the Executive with certain benefits in the event the Executive's employment is terminated as a result of, or in connection with, a Change of Control.

NOW, THEREFORE, IT IS HEREBY AGREED AS FOLLOWS:

1. *Certain Definitions.* (a) The "Effective Date" shall mean the first date during the Change of Control Period (as defined in Section l(b)) on which a Change of Control (as defined in Section 2) occurs. Anything in this Agreement to the contrary notwithstanding, if a Change of Control occurs during the Change of Control Period and if the Executive's employment with the Employer (as defined in Section 1(d)) is terminated prior to the date on which the Change of Control occurs, and it is reasonably demonstrated by the Executive that such termination of employment (i) was at the request of a third party who has taken steps reasonably calculated to effect a Change of Control or (ii) otherwise arose in connection with or in anticipation of a Change of Control, then for all purposes of this Agreement the "Effective Date" shall mean the date immediately prior to the date of such termination of employment.

(b) The "Change of Control Period" shall mean the period commencing on the date hereof and ending on the third anniversary of the date hereof; provided, however, that commencing on the date one year after the date hereof, and on each annual anniversary of such date (such date and each annual anniversary thereof shall be hereinafter referred to as the "Renewal Date"), unless previously terminated, the Change of Control Period shall be automatically extended so as to terminate three years from such Renewal Date, unless at least 60 days prior to the Renewal Date the Company shall give notice to the Executive that the Change of Control Period shall not be so extended.

(c) The "Company" shall mean OGE Energy Corp. and any successor to its business and/or assets which assumes and agrees to perform this Agreement, pursuant to Section 11 herein, by operation of law, or otherwise.

(d) Employer" shall mean (i) in the event the Executive is an officer of the Company and not of any Affiliate (as defined in Section 1(e)) of the Company immediately prior to the Effective Date, the Company; (ii) in the event the Executive is an officer of one or more Affiliates of the Company, but not of the Company, immediately prior to the Effective Date, any such Affiliate; and (iii) in the event the Executive is an officer of the Company and one or more Affiliates of the Company immediately prior to the Effective Date, any such entity of which the Executive is an officer immediately prior to the Effective Date.

(e) "Affiliate", for all purposes of this Agreement other than Section 5 and Section 6(e), shall mean, with respect to any Person (as defined in Section 2(a)), any other Person that directly or indirectly through one or more intermediaries controls, is controlled by or is under common control with, the Person in question. As used herein, the term "control" means the possession, direct or indirect, of the power to direct or cause the direction of the management and policies of a Person, whether through ownership of voting securities, by contract or otherwise. For purposes of Sections 5 and 6(e), however, "Affiliate" shall mean any Person which is a member of the same controlled group of corporations, trades or businesses within the meaning of the Section 414(b) or (c) of the Internal Revenue Code of 1986, as amended (the "Code"), as any other Person, provided that for purposes of Section 5 (but not for purposes of Section 6(e)) in applying Code Section 1563(a)(1), (2), and (3) in determining a controlled group of corporations under Code Section 414(b), the language "at least 50 percent" shall be used instead of "at least 80 percent" each place it appears in Code Section 1563(a)(1), (2), and (3), and in applying Treasury Reg. § 1.414(c)-2 for purposes of determining trades or businesses (whether or not incorporated) that are under common control for purposes of Code Section 414(c), "at least 50 percent" shall be used instead of "at least 80 percent" each place it appears in

Treasury Reg. § 1.414(c)-2.

2. *Change of Control.* For the purpose of this Agreement, a "Change of Control" shall mean:

(a) The acquisition by any individual, entity or group (within the meaning of Section 13(d)(3) or 14(d)(2) of the Securities Exchange Act of 1934, as amended (the "Exchange Act")) (a "Person") of beneficial ownership (within the meaning of Rule 13d-3 promulgated under the Exchange Act) of 20% or more of either (i) the then-outstanding shares of common stock of the Company (the "Outstanding Company Common Stock") or (ii) the combined voting power of the then-outstanding voting securities of the Company entitled to vote generally in the election of directors (the "Outstanding Company Voting Securities"); provided, however, that for purposes of this subsection (a), the following acquisitions shall not constitute a Change of Control: (i) any acquisition directly from the Company, (ii) any acquisition by the Company, (iii) any acquisition by any employee benefit plan (or related trust) sponsored or maintained by the Company or any corporation or other Person controlled by the Company, or (iv) any acquisition by any corporation or other Person pursuant to a transaction which complies with clauses (i), (ii) and (iii) of subsection (c) of this Section 2; or

(b) Individuals who, as of the date hereof, constitute the Board (the "Incumbent Board") cease for any reason to constitute at least a majority of the Board; provided, however, that any individual becoming a director subsequent to the date hereof whose election, or nomination for election by the Company's shareowners, was approved by a vote of at least a majority of the directors then comprising the Incumbent Board shall be considered as though such individual were a member of the Incumbent Board, but excluding, for this purpose, any such individual whose initial assumption of office occurs as a result of an actual or threatened election contest with respect to the election or removal of directors or other actual or threatened solicitation of proxies or consents by or on behalf of a Person other than the Board; or

(c) Consummation of a reorganization, merger, share exchange or consolidation or sale or other disposition of all or substantially all of the assets of the Company (a "Business Combination"), in each case, unless, following such Business Combination, (i) all or substantially all of the individuals and entities who were the beneficial owners, respectively, of the Outstanding Company Common Stock and Outstanding Company Voting Securities immediately prior to such Business Combination beneficially own, directly or indirectly, more than 60% of, respectively, the then-outstanding shares of common stock or equity interests and the combined voting power of the then-outstanding voting securities entitled to vote generally in the election of directors or other controlling persons, as the case may be, of the corporation or other Person resulting from such Business Combination (including, without limitation, a corporation or other Person which as a result of such transaction owns the Company or all or substantially all of the Company's assets either directly or through one or more subsidiaries) in substantially the same proportions as their ownership, immediately prior to such Business Combination of the Outstanding Company Common Stock and Outstanding Company Voting Securities, as the case may be, (ii) no Person (excluding any corporation or other Person resulting from such Business Combination or any employee benefit plan (or related trust) of the Company or such corporation or other Person resulting from such Business Combination) beneficially owns, directly or indirectly, 20% or more of, respectively, the then-outstanding shares of common stock or equity interests of the corporation or other Person resulting from such Business Combination, or the combined voting power of the then-outstanding voting securities of such corporation or other Person except to the extent that such ownership existed with respect to the Company prior to the Business Combination and (iii) at least a majority of the members of the board of directors or other governing body of the corporation or other Person resulting from such Business Combination were members of the Incumbent Board at the time of the execution of the initial agreement, or of the action of the Board, providing for such Business Combination; or

(d) Approval by the shareowners of the Company of a complete liquidation or dissolution of the Company.

3. *Employment Period*. The Executive shall remain in the employ of the Employer subject to the terms and conditions of this Agreement, for the period commencing on the Effective Date and ending, unless earlier terminated by the occurrence of the Executive's Date of Termination as provided in Section 5, on the third anniversary of such date (the "Employment Period").

4. *Terms of Employment*. (a) *Position and Duties.* (i) During the Employment Period, (A) the Executive's position (including status, offices, titles and reporting requirements), authority, duties and responsibilities shall be at least commensurate in all material respects with the most significant of those held, exercised and assigned at any time during the 120-day period immediately preceding the Effective Date and (B) the Executive's services shall be performed at the location where the Executive performed the majority of the Executive's services immediately preceding the Effective Date or any office or location less than 50 miles from such location.

(ii) During the Employment Period, and excluding any periods of vacation and sick leave to which the Executive is entitled, the Executive agrees to devote reasonable attention and time during normal business hours to the business and affairs of the Employer and, to the extent necessary to discharge the responsibilities assigned to the Executive hereunder, to use the Executive's reasonable best efforts to perform faithfully and efficiently such responsibilities. During the Employment Period it shall not be a violation of this Agreement for the Executive to (A) serve on corporate, civic or charitable boards or committees, (B) deliver lectures, fulfill speaking engagements or teach at educational institutions, and (C) manage personal investments, so long as such activities do not significantly interfere with the performance of the Executive's responsibilities as an employee of the Employer in accordance with this Agreement. It is expressly understood and agreed that to the extent that any such activities have been conducted by the Executive prior to the Effective Date, the continued conduct of such activities (or the conduct of activities similar in nature and scope thereto) subsequent to the Effective Date shall not thereafter be deemed to interfere with the performance of the Executive's responsibilities to the Employer.

(b) *Compensation.* (i) *Base Salary.* During the Employment Period, the Executive shall receive an annual base salary ("Annual Base Salary"), which shall be paid at a monthly rate, at least equal to twelve times the highest monthly base salary paid or payable, including any base salary which has been earned but deferred, to the Executive by the Company and its Affiliates in respect of the twelve-month period immediately preceding the month in which the Effective Date occurs. During the Employment Period, the Annual Base Salary shall be reviewed no more than 12 months after the last salary increase awarded to the Executive prior to the Effective Date and thereafter at least annually. Any increase in Annual Base Salary shall not serve to limit or reduce any other obligation to the Executive under this Agreement. Annual Base Salary shall not be reduced after any such increase and the term Annual Base Salary as utilized in this Agreement shall refer to Annual Base Salary as so increased.

(ii) *Annual Bonus*. In addition to Annual Base Salary, the Executive shall be awarded, for each fiscal year ending during the Employment Period, an annual bonus (the "Annual Bonus") in cash at least equal to the Executive's highest bonus under the Company's or any of its Affiliates' Annual Incentive Compensation Plan, or any comparable bonus under any predecessor or successor plan of the Company or any of its Affiliates, for the last three full fiscal years ending prior to the Effective Date (annualized in the event that the Executive was not employed by the Employer for the whole of such fiscal year) (the "Recent Annual Bonus"). Each such Annual Bonus shall be paid during the period beginning on the first day of the first month and ending on the 15th day of the third month of the fiscal year next following the fiscal year for which the Annual Bonus is awarded, unless the Executive shall elect to defer the receipt of such Annual Bonus pursuant to the terms of a plan of the Company or an Affiliate thereof permitting such deferral.

(iii) *Incentive, Savings and Retirement Plans.* During the Employment Period, the Executive shall be entitled to participate in all incentive, savings and retirement plans, practices, policies and programs applicable generally to other peer executives of the Company and its Affiliates, including, but not limited to, those specified in Exhibit A attached hereto, but in no event shall such plans, practices, policies and programs provide the Executive with incentive opportunities (measured with respect to both regular and special incentive opportunities, to the extent, if any, that such distinction is applicable), savings opportunities and retirement benefit opportunities, in each case, less favorable, in the aggregate, than the most favorable of those provided by the Company and its Affiliates for the Executive under such plans, practices, policies and programs as in effect at any time during the 120-day period immediately preceding the Effective Date or if more favorable to the Executive, those provided generally at any time after the Effective Date to other peer executives of the Company and its Affiliates.

(iv) *Welfare Benefit Plans.* During the Employment Period, the Executive and/or the Executive's family, as the case may be, shall be eligible for participation in and shall receive all benefits under welfare benefit plans, practices, policies and programs provided by the Company and its Affiliates (including, without limitation, medical, prescription, dental, vision, disability, employee life, group life, accidental death and travel accident insurance plans and programs) to the extent applicable generally to other peer executives of the Company and its Affiliates, but in no event shall such plans, practices, policies and programs provide the Executive with benefits which are less favorable, in the aggregate, than the most favorable of such plans, practices, policies and programs in effect for the Executive at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive, those provided generally at any time after the Effective Date to other peer executives of the Company and its Affiliates.

(v) *Expenses.* During the Employment Period, the Executive shall be entitled to receive prompt reimbursement for all reasonable expenses incurred by the Executive in accordance with the most favorable policies, practices and procedures of the Company and its Affiliates in effect for the Executive at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive, as in effect generally at any time thereafter with respect to other peer executives of the Company and its Affiliates.

(vi) *Fringe Benefits.* During the Employment Period, the Executive shall be entitled to fringe benefits, including, without limitation, tax and financial planning services, payment of club dues, and, if applicable, use of an automobile and payment of related expenses, in accordance with the most favorable plans, practices, programs and policies of the Company and its Affiliates in effect for the Executive at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive, as in effect generally at any time thereafter with respect to other peer executives of the Company and its Affiliates.

(vii) *Office and Support Staff*. During the Employment Period, the Executive shall be entitled to an office or offices of a size and with furnishings and other appointments, and to personal secretarial and other assistance, at least equal to the most favorable of the foregoing provided to the Executive by the Company and its Affiliates at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive, as provided generally at any time thereafter with respect to other peer executives of the Company and its Affiliates.

(viii) *Vacation*. During the Employment Period, the Executive shall be entitled to paid vacation in accordance with the most favorable plans, policies, programs and practices of the Company and its Affiliates as in effect for the Executive at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive, as in effect generally at any time thereafter with respect to other peer executives of the Company and its Affiliates.

5. *Termination of Employment*. Subject to the provisions of this Section 5, the Executive's employment shall be deemed terminated for purposes of this Agreement when the Executive incurs a "separation from service" (as such phrase is defined in Code Section 409A and the regulations promulgated thereunder) with the Employer and its Affiliates because of death, retirement or termination of employment for any other reason, including any reason specified in Section 5(a), (b) or (c) below; provided, however, that no termination shall be deemed to occur for purposes of the Agreement while the Executive continues to perform services for the Employer or its Affiliates in a capacity as an employee or as an independent contractor at a level that is more than 20% of the average level of bona fide services performed (whether as an employee or otherwise) by the Executive during the immediately preceding 36-month period (or, if employed less than 36 months, such lesser period).

(a) *Death or Disability*. The Executive's employment shall terminate automatically upon the Executive's death during the Employment Period. If the Employer determines in good faith that the Disability of the Executive has occurred during the Employment Period (pursuant to the definition of Disability set forth below), it may give to the Executive written notice in accordance with Section 12(b) of this Agreement of its intention to terminate the Executive's employment. In such event, the Executive's employment with the Employer shall terminate effective on the 30th day after receipt of such notice by the Executive (the "Disability Effective Date"), provided that, within the 30 days after such receipt, the Executive shall not have returned to full-time performance of the Executive's duties. For purposes of this Agreement, "Disability" shall mean the absence of the Executive from the Executive's duties with the Employer on a full-time basis for 180 consecutive business days as a result of incapacity due to mental or physical illness which is determined to be total and permanent by a physician selected by the Employer or its insurers and acceptable to the Executive or the Executive's legal representative.

(b) *Cause*. The Employer may terminate the Executive's employment during the Employment Period for Cause. For purposes of this Agreement, "Cause" shall mean:

(i) the willful and continued failure of the Executive to perform substantially the Executive's duties with the Employer or one of its Affiliates (other than any such failure resulting from incapacity due to physical or mental illness), after a written demand for substantial performance is delivered to the Executive by the Board or the Chief Executive Officer of the Company which specifically identifies the manner in which the Board or Chief Executive Officer believes that the Executive has not substantially performed the Executive's duties, or

(ii) the willful engaging by the Executive in illegal conduct or gross misconduct which is materially and demonstrably injurious to the Employer.

For purposes of this provision, no act or failure to act, on the part of the Executive, shall be considered "willful" unless it is done, or omitted to be done, by the Executive in bad faith or without reasonable belief that the Executive's action or omission was in the best interests of the Employer. Any act, or failure to act, based upon authority given pursuant to a resolution duly adopted by the Board or upon the instructions of the Chief Executive Officer or a senior officer of the Company (in either case, who is not the Executive) or based upon the advice of counsel for the Company shall be conclusively presumed to be done, or omitted to be done, by the Executive in good faith and in the best interests of the Employer. The cessation of employment of the Executive shall not be deemed to be for Cause unless and until there shall have been delivered to the Executive a copy of a resolution duly adopted by the affirmative vote of not less than three quarters of the entire membership of the Board at a meeting of the Board called and held for such purpose (after reasonable notice is provided to the Executive and the Executive is given an opportunity, together with counsel, to be heard before the Board), finding that, in the good faith opinion of the Board, the Executive is guilty of the conduct described in subparagraph (i) or (ii) above, and specifying the particulars thereof in detail.

(c) *Good Reason*. The Executive's employment may be terminated by the Executive for Good Reason. For purposes of this Agreement, "Good Reason" shall mean:

(i) the assignment to the Executive of any duties inconsistent in any respect with the Executive's position (including status, offices, titles and reporting requirements), authority, duties or responsibilities as contemplated by Section 4(a) of this Agreement, or any other action by the Employer which results in a diminution in such position, authority, duties or responsibilities, excluding for this purpose an isolated, insubstantial and inadvertent action not taken in bad faith and which is remedied by the Company promptly after receipt of notice thereof given by the Executive;

(ii) any failure by the Employer to comply with any of the provisions of Section 4(b) of this Agreement, other than an isolated, insubstantial and inadvertent failure not occurring in bad faith and which is remedied by the Company promptly after receipt of notice thereof given by the Executive;

(iii) the Employer's requiring the Executive to be based at any office or location other than as provided in Section 4(a)(i)(B) hereof or the Employer's requiring the Executive to travel on Employer business to a substantially greater extent than required immediately prior to the Effective Date;

(iv) any purported termination by the Employer of the Executive's employment otherwise than as expressly permitted by this Agreement; or

(v) any failure by the Employer to comply with and satisfy Section 11(c) of this Agreement.

For purposes of this Section 5(c), any good faith determination of "Good Reason" made by the Executive shall be conclusive.

(d) *Notice of Termination*. Any termination by the Employer for Cause, or by the Executive for Good Reason, shall be communicated by Notice of Termination to the other party hereto given in accordance with Section 12(b) of this Agreement. For purposes of this Agreement, a "Notice of Termination" means a written notice which (i) indicates the specific termination provision in this Agreement relied upon, (ii) to the extent applicable, sets forth in reasonable detail the facts and circumstances claimed to provide a basis for termination of the Executive's employment under the provision so indicated and (iii) if the Date of Termination (as defined below) is other than the date of receipt of such notice, specifies the termination date (which date shall be not more than thirty days after the giving of such notice). The failure by the Executive or the Employer to set forth in the Notice of Termination any fact or circumstance which contributes to a showing of Good Reason or Cause shall not waive any right of the Executive or the Employer, respectively, hereunder or preclude the Executive or the Employer, respectively, from asserting such fact or circumstance in enforcing the Executive's or the Employer's rights hereunder.

(e) *Date of Termination*. "Date of Termination" in respect of the Executive's separation from service under this Agreement means (i) if the Executive's employment is terminated by the Employer for Cause, or by the Executive for Good Reason, the date of receipt of the Notice of Termination or any later date specified therein, as the case may be, (ii) if the Executive's employment is terminated by the Employer other than for Cause or Disability, the Date of Termination shall be the date on which the Employer notifies the Executive of such termination or any later date specified therein, (iii) if the Executive's employment is terminated by reason of death or Disability, the Date of Termination shall be the date of death of the Executive or the Disability Effective Date, as the case may be, and (iv) if the Executive's employment is terminated by the Executive voluntarily other than for Good Reason, the Date of Termination shall be the date on which the Executive notifies the Employer of such termination or any later date specified therein.

6. *Obligations of the Company upon Termination.* Subject to Section 6(e) below:

(a) *Good Reason; Other Than for Cause, Death or Disability.* If, during the Employment Period, the Employer shall terminate the Executive's employment other than for Cause, death or Disability or the Executive shall terminate employment for Good Reason, the Employment Period shall thereupon terminate and:

(i) the Company shall pay to the Executive in a lump sum in cash within 30 days after the Date of Termination the aggregate of the following amounts, subject to reduction as set forth in Section 9:

A. the sum of (1) the Executive's Annual Base Salary through the Date of Termination to the extent not theretofore paid, (2) the product of (x) the higher of (I) the Recent Annual Bonus and (II) the Annual Bonus paid or payable, including any bonus or portion thereof which has been earned but deferred (and annualized for any fiscal year consisting of less than twelve full months or during which the Executive was employed for less than twelve full months), for the most recently completed fiscal year during the Employment Period, if any (such higher amount being referred to as the "Highest Annual Bonus") and (y) a fraction, the numerator of which is the number of days in the current fiscal year through the Date of Termination, and the denominator of which is 365 and (3) any accrued vacation pay to the extent not theretofore paid (the sum of the amounts described in clauses (1), (2), and (3) shall be hereinafter referred to as the "Accrued Obligations"); and

B. the amount equal to the product of (1) 2.99 and (2) the sum of (x) the Executive's Annual Base Salary and (y) the Highest Annual Bonus;

(ii) for three years after the Executive's Date of Termination, the Company shall continue benefits under the medical, prescription, vision, dental, disability, employee life, group life, accidental death and travel accident insurance plans programs to the Executive and/or the Executive's family at least equal to those which would have been provided to them in accordance with the plans, programs, practices and policies described in Section 4(b)(iv) of this Agreement if the Executive's employment had not been terminated or, if more favorable to the Executive, as in effect generally at any time thereafter with respect to other peer executives of the Company and its Affiliates and their families, provided, however, that if the Executive becomes reemployed with another employer and is eligible to receive medical or other welfare benefits under another employer-provided plan, the medical and other welfare benefits described herein shall be secondary to those provided under such other plan during such applicable period of eligibility, and provided further, that (A) with respect to any such benefits providing for the reimbursement of medical expenses referred to in Section 105(b) of the Code under a self-insured medical reimbursement plan (within the meaning of Code Section 105(h)), (a "Self-Insured Medical Plan"), including, without limitation, medical, prescription, vision or dental benefits, that are incurred following the period the Executive would be entitled (or would, but for this Section 6(a)(ii), be entitled) to continuation coverage under such plan under Code Section 4980B (COBRA) if the Executive had elected such coverage and paid the applicable premiums, the reimbursement of an eligible medical expense must be made on or before the last day of the calendar year following the calendar year in which the expense was incurred and (B) the Executive and/or the Executive's family pays to the Company the cost, on an after-tax basis, for the premium payments (both the employee and employer portion) required for such continued coverage under any Self-Insured Medical Plan. For purposes of determining eligibility (but not the time of commencement of benefits) of the Executive for retiree benefits pursuant to such plans, practices, programs and policies, the Executive shall be considered to have remained employed until three years after the Date of Termination and to have retired on the last day of such period;

(iii) the Company shall, at its sole expense as incurred, provide the Executive with reasonable outplacement services the scope and provider of which shall be selected by the Executive in [his][her] sole discretion, provided that, such services must be provided and the expenses therefor incurred prior to the end of the second calendar year following the calendar year in which the Date of Termination occurs, and provided further, that the Company shall pay all reimbursements for such expenses so incurred not later than the end of the third calendar year following the calendar year in which the Date of Termination occurs;

(iv) to the extent not theretofore paid or provided, the Company shall timely pay or provide to the Executive any other amounts or benefits required to be paid or provided or which the Executive is eligible to receive under any plan, program, policy or practice or contract or agreement of the Company or its Affiliates (such other amounts and benefits shall be hereinafter referred to as the "Other Benefits"); and

(v) on or about January 31 of the year following the year in which the Date of Termination occurs and continuing on or about each January 31 thereafter until the year following the year in which the Executive's continued coverage under any Self-Insured Medical Plan pursuant to the first sentence of Section 6(a)(ii) terminates, the Company will make a payment in cash to the Executive and/or the Executive's family equal, on an after-tax basis, to the amount, if any, the Executive and/or the Executive's family paid in premium payments during the immediately preceding calendar year for continued coverage under any Self-Insured Medical Plan described in Section 6(a)(ii) exceeds the amount the Executive and/or the Executive's family would have paid if the Executive had remained in employment during such year, provided that each such cash payment by the Company pursuant to this Section 6(a)(v) shall be considered a separate payment and not one of a series of payments for purposes of Code Section 409A.

Following such termination of the Executive's employment, except as set forth in this Section 6(a) or Section 8 or 9, the Executive shall have no further rights to compensation or other benefits under this Agreement.

(b) *Death.* If the Executive's employment is terminated by reason of the Executive's death during the Employment Period, this Agreement and the Employment Period shall thereupon terminate without further obligations to the Executive's legal representatives under this Agreement, other than for payment of Accrued Obligations and the timely payment or provision of Other Benefits. Accrued Obligations shall be paid to the Executive's estate or beneficiary, as applicable, in a lump sum in cash within 30 days of the Date of Termination. With respect to the provision of Other Benefits, the term Other Benefits as utilized in this Section 6(b) shall include, without limitation, and the Executive's estate and/or beneficiaries shall be entitled to receive, benefits at least equal to the most favorable benefits provided by the Company and its Affiliates to the estates and beneficiaries of peer executives of the Company and such Affiliates under such plans, programs, practices and policies relating to death benefits, if any, as in effect with respect to other peer executives and their beneficiaries at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive's estate and/or the Executive's beneficiaries, as in effect on the date of the Executive's death with respect to other peer executives of the Company and its Affiliates and their beneficiaries.

(c) *Disability.* If the Executive's employment is terminated by reason of the Executive's Disability during the Employment Period, this Agreement and the Employment Period shall thereupon terminate without further obligations to the Executive, other than for payment of Accrued Obligations and the timely payment or provision of Other Benefits. Accrued Obligations shall be paid to the Executive in a lump sum in cash within 30 days of the Date of Termination. With respect to the provision of Other Benefits, the term "Other Benefits" as utilized in this Section 6(c) shall include, and the Executive shall be entitled after the Disability Effective Date to receive, disability and other benefits at least equal to the most favorable of those generally provided by the Company and its Affiliates to disabled executives and/or their families in accordance with such plans, programs, practices and policies relating to disability, if any, as in effect generally with respect to other peer executives and their families at any time during the 120-day period immediately preceding the Effective Date or, if more favorable to the Executive and/or the Executive's family, as in effect at any time thereafter generally with respect to other peer executives of the Company and its Affiliates and their families.

(d) *Cause; Other than for Good Reason.* If the Executive's employment shall be terminated for Cause during the Employment Period, this Agreement and the Employment Period shall thereupon terminate without further obligations to the Executive other than the obligation to pay to the Executive (x) [his][her] Annual Base Salary through the Date of Termination and (y) Other Benefits, in each case to the extent theretofore unpaid. All amounts payable under clause (x) shall be paid to the Executive in a lump sum in cash within 30 days of the Date of Termination. If the Executive voluntarily terminates employment during the Employment Period, excluding a termination for Good Reason, this Agreement and the Employment Period shall thereupon terminate without further obligations to the Executive, other than for Accrued Obligations and the timely payment or provision of Other Benefits. In such case, all Accrued Obligations shall be paid to the Executive in a lump sum in cash within 30 days of the Date of Termination.

(e) (i) Notwithstanding anything in this Section 6 or any other provision of this Agreement to the contrary, if, at the Executive's Date of Termination, stock of the Company or any Affiliate is publicly traded on an established securities market or otherwise and the Executive is a "Specified Employee" (as defined in Section 6(e)(ii)) at the Date of Termination, then the Company will defer the payment or commencement of the payment, as the case may be, of any amounts described in Section 6(a)(i)(A)(2) (but only where payable under Section 6(a), 6(c) or 6(d)), Section 6(a)(i)(B) and Section 6(a)(v) that, in any such case, otherwise become payable during the first six months following the Executive's Date of Termination, until the earlier of (A) the first day of the seventh month following the Executive's Date of Termination or (B) the Executive's death. Any payments or benefits delayed as a result of the preceding sentence shall be accumulated and paid in a lump sum, without interest, as soon as practicable but not later than five business days after the first day of the seventh month following the Executive's Date of Termination (or the Executive's earlier death). Thereafter, payments will resume in accordance with this Agreement.

(ii) For purposes of this Agreement, a "Specified Employee" means, during the 12-month period beginning on April 1st of 2011 or on April 1st of any subsequent calendar year, an employee of the Company or its Affiliates who met the requirements of Section 416(i)(1)(A)(i), (ii) or (iii) of the Code (applied in accordance with the regulations thereunder and without regard to Code Section 416(i)(5)) for being a "key employee" at any time during the 12-month period ending on the December 31st immediately preceding such April 1st.

7. *Nonexclusivity of Rights.* Nothing in this Agreement shall prevent or limit the Executive's continuing or future participation in any plan, program, policy or practice provided by the Company or any of its Affiliates and for which the Executive may qualify, nor, subject to Section 12(f), shall anything herein limit or otherwise affect such rights as the Executive may have under any contract or agreement with the Company or any of its Affiliates. Amounts which are vested benefits or which the Executive is otherwise entitled to receive under any plan, policy, practice or program of or any contract or agreement with the Company or any of its Affiliates at or subsequent to the Date of Termination shall be payable in accordance with such plan, policy, practice or program or contract or agreement except as explicitly modified by this Agreement.

8. *Full Settlement.* Subject to Section 9 herein, the Company's obligation to make the payments provided for in this Agreement and otherwise to perform its obligations hereunder shall not be affected by any set-off, counterclaim, recoupment, defense or other claim, right or action which the Company or any of its Affiliates may have against the Executive or others. In no event shall the Executive be obligated to seek other employment or take any other action by way of mitigation of the amounts payable to the Executive under any of the provisions of this Agreement and such amounts shall not be reduced whether or not the Executive obtains other employment (except as provided in Section 6(a)(ii) where the medical and other welfare benefits described therein shall be secondary to those provided under another employer-provided plan). Notwithstanding any other provision of this Agreement, the Company agrees to pay as incurred but in no event later than the end of the calendar year following the calendar year in which incurred, to the full extent permitted by law, all legal fees and expenses which the Executive may reasonably incur during the period beginning on the date of this Agreement and ending ten (10) years after the Date of Termination as a result of any contest (regardless of the outcome thereof) by the Company, the Executive or others of the validity or enforceability of, or liability under, any provision of this Agreement or any guarantee of performance thereof (including as a result of any contest by the Executive about the amount of any payment pursuant to this Agreement), plus in each case interest on any delayed payment at the applicable Federal rate provided for in Section 7872(f)(2)(A) of the Code.

9. *Certain Reduction of Payments by the Company*.

(a) For purposes of this Section 9, (i) a Payment shall mean any payment or distribution in the nature of compensation to or for the benefit of the Executive, whether paid or payable pursuant to this Agreement or otherwise, including, without limitation, any stock option, stock appreciation right or similar right, or the lapse or termination of any restriction on or the vesting or exercisability of any of the foregoing; (ii) Change of Control Payment shall mean a Payment paid or payable pursuant to this Agreement (disregarding this Section); (iii) Net After Tax Receipt shall mean the Present Value of a Payment net of all taxes imposed on the Executive with respect thereto under Sections 1 and 4999 of the Code, determined by applying the highest marginal rate under Section 1 of the Code which applied to the Executive's taxable income for the immediately preceding taxable year; (iv) "Present Value" shall mean such value determined in accordance with Section 280G(d)(4) of the Code; and (v) "Reduced Amount" shall mean the greatest aggregate amount of Change of Control Payments which (A) is less than the sum of all Change of Control Payments and (B) results in aggregate Net After Tax Receipts which are equal to or greater than the Net After Tax Receipts which would result if the Executive were paid the sum of all Change of Control Payments.

(b) Anything in this Agreement to the contrary notwithstanding, in the event Ernst & Young or such other certified public accounting firm designated by the Executive (the "Accounting Firm") shall determine that receipt of all Payments would subject the Executive to tax under Section 4999 of the Code, it shall determine whether some amount of Change of Control Payments would meet the definition of a "Reduced Amount." If the Accounting Firm determines that there is a Reduced Amount, the aggregate Change of Control Payments shall be reduced to such Reduced Amount as provided below. All fees payable to the Accounting Firm shall be paid solely by the Company.

(c) If Accounting Firm determines that aggregate Change of Control Payments should be reduced to the Reduced Amount, the Change of Control Payments shall be reduced or eliminated, as determined by Accounting Firm, in the following order so that after such reduction or elimination the Present Value of the aggregate Change of Control Payments equals the Reduced Amount: (i) cash payments, (ii) outplacement services and (iii) welfare benefits. The Company shall promptly give the Executive notice of the Accounting Firm's determinations and a copy of the detailed calculations thereof showing that aggregate Change of Control Payments should be reduced to the Reduced Amount and the required reduction or elimination of such Change of Control Payments in the order set forth above so that after reduction or elimination the Present Value of the aggregate Change of Control Payments equals the Reduced Amount. All determinations made by Accounting Firm under this Section shall be binding upon the Company and the Executive and shall be made within 60 days of the Executive's Date of Termination. As promptly as practicable following such determination but in no event later than the last day of the calendar year in which the Date of Termination occurs or, if later and the Executive is not permitted, directly or indirectly, to designate the year of payment, by the 15th day of the third calendar month following the Date of Termination, the Company shall pay to or distribute for the benefit of the Executive such Change of Control Payments as are then due to the Executive under this Agreement and shall promptly pay to or distribute for the benefit of the Executive in the future such Change of Control Payments as become due to the Executive under this Agreement.

(d) While it is the intention of the Company to reduce the amounts payable or distributable to the Executive hereunder only if the aggregate Net After Tax Receipts to the Executive would thereby be increased, as a result of the uncertainty in the application of Section 4999 of the Code at the time of the initial determination by Accounting Firm hereunder, it is possible that amounts will have been paid or distributed by the Company to or for the benefit of the Executive pursuant to this Agreement which should not have been so paid or distributed ("Overpayment") or that additional amounts which will have not been paid or distributed by the Company to or for the benefit of the Executive pursuant to this Agreement could have been so paid or distributed ("Underpayment"), in each case, consistent with the calculation of the Reduced Amount hereunder. In the event that Accounting Firm, based upon the assertion of a deficiency by the Internal Revenue Service against either the Company or the Executive which Accounting Firm believes has a high probability of success determines that an Overpayment has been made, any such Overpayment paid or distributed by the Company to or for the benefit of the Executive shall be treated for all purposes as a loan to the Executive which the Executive shall repay to the Company together with interest at the applicable federal rate provided for in Section 7872(f)(2) of the Code; provided, however, that no such loan shall be deemed to have been made and no amount shall be payable by an Executive to the Company if and to the extent such deemed loan and payment would not either reduce the amount on which the Executive is subject to tax under Section 1 and Section 4999 of the Code or generate a refund of such taxes. In the event that Accounting Firm, based upon controlling precedent or substantial authority, determines that an Underpayment has occurred, any such Underpayment shall be promptly paid by the Company to or for the benefit of the Executive together with interest at the applicable federal rate provided for in Section 7872(f)(2) of the Code, but in no event shall the Underpayment be paid later than the end of the first calendar year in which the calculation of the Underpayment is administratively practicable.

10. *Confidential Information*. The Executive shall hold in a fiduciary capacity for the benefit of the Company all secret or confidential information, knowledge or data relating to the Company or any of its Affiliates, and their respective businesses, which shall have been obtained by the Executive during the Executive's employment by the Company or any of its Affiliates and which shall not be or become public knowledge (other than by acts by the Executive or representatives of the Executive in violation of this Agreement).

After termination of the Executive's employment with the Employer, the Executive shall not, without the prior written consent of the Employer or as may otherwise be required by law or legal process, communicate or divulge any such information, knowledge or data to anyone other than the Employer and those designated by it. In no event shall an asserted violation of the provisions of this Section 10 constitute a basis for deferring or withholding any amounts otherwise payable to the Executive under this Agreement.

11. *Successors.* (a) This Agreement is personal to the Executive and without the prior written consent of the Company shall not be assignable by the Executive otherwise than by will or the laws of descent and distribution. This Agreement shall inure to the benefit of and be enforceable by the Executive's legal representatives.

(b) This Agreement shall inure to the benefit of and be binding upon the Company and its successors and assigns.

(c) The Company will require any successor (whether direct or indirect, by purchase, merger, consolidation or otherwise) to all or substantially all of the business and/or assets of the Company to assume expressly and agree to perform this Agreement in the same manner and to the same extent that the Company would be required to perform it if no such succession had taken place.

12. *Miscellaneous.* (a) This Agreement shall be governed by and construed in accordance with the laws of the State of Oklahoma, without reference to principles of conflict of laws. The captions of this Agreement are not part of the provisions hereof and shall have no force or effect. This Agreement may not be amended or modified otherwise than by a written agreement executed by the parties hereto or their respective successors and legal representatives.

(b) All notices and other communications hereunder shall be in writing and shall be given by hand delivery to the other party or by registered or certified mail, return receipt requested, postage prepaid, addressed as follows:

If to the Executive: ____________________________
OGE Energy Corp.
321 North Harvey
Oklahoma City, Oklahoma 73102

If to the Company or the Employer:
OGE Energy Corp.
321 North Harvey
Oklahoma City, Oklahoma 73102
Attention: General Counsel

or to such other address as either party shall have furnished to the other in writing in accordance herewith. Notice and communications shall be effective when actually received by the addressee.

(c) The invalidity or unenforceability of any provision of this Agreement shall not affect the validity or enforceability of any other provision of this Agreement.

(d) The Company may withhold from any amounts payable under this Agreement such Federal, state, local or foreign taxes as shall be required to be withheld pursuant to any applicable law or regulation.

(e) The Executive's or the Company's failure to insist upon strict compliance with any provision of this Agreement or the failure to assert any right the Executive or the Company may have hereunder, including, without limitation, the right of the Executive to terminate employment for Good Reason pursuant to Section 5(c)(i)-(v) of this Agreement, shall not be deemed to be a waiver of such provision or right or any other provision or right of this Agreement.

(f) The Executive and the Company acknowledge that, except as may otherwise be provided under any other written agreement between the Executive and the Company or any of its Affiliates, the employment of the Executive by the Company or any of its Affiliates is "at will" and, subject to Section 1(a) hereof, prior to the Effective Date, the Executive's employment may be terminated by either the Executive or the Company or any of its Affiliates, as the case may be, at any time prior to the Effective Date, in which case the Executive shall have no further rights under this Agreement. From and after the date hereof, this Agreement shall supersede any other agreement between the parties with respect to the subject matter hereof.

(g) To the extent applicable, it is intended that the compensation arrangements under this Agreement be in full compliance with the provisions of Section 409A of the Code. This Agreement shall be administered in a manner consistent with this intent. Notwithstanding any provision of the Plan to the contrary, a distribution to be made as of a specified date in Section 6 shall be treated for purposes of Code Section 409A as made on the date specified if the distribution is made at such date specified or a later date in the same calendar year or, if later, and provided the Executive is not permitted, directly or indirectly, to designate the year in which the distribution is made, by the 15th day of the third calendar month following the specified date. In addition, to the extent any provision of this Agreement, is or will be in violation of Section 409A of the Code and the regulations thereunder, this Agreement shall be amended in such manner as the parties may agree such that the Agreement is or remains in compliance with Section 409A of the Code and the foregoing intent of the parties is maintained to the maximum extent possible. Each party is responsible for reviewing this Agreement for compliance with Section 409A.

(h) The provisions of this Agreement are not intended, and should not be construed to be legal, business or tax advice. The Company, the Executive and any other party having any interest herein are hereby informed that the U.S. federal tax advice contained in this document (if any) is not intended or written to be used, and cannot be used, for the purpose of (i) avoiding penalties under the Code or (ii) promoting, marketing or recommending to any party any transaction or matter addressed herein.

IN WITNESS WHEREOF, the Executive has hereunto set the Executive's hand and, pursuant to the authorization from its Board of Directors, OGE Energy Corp. has caused these presents to be executed in its name on its behalf, all as of the day and year first above written.

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OGE ENERGY CORP.

By ______________________________

Peter B. Delaney

Chairman of the Board, President and Chief Executive Officer

Exhibit A

Incentive, Savings and Retirement Plans

1 Annual Incentive Compensation Plan

2 Stock Incentive Plan

3 OGE Energy Corp. Employees' Stock Ownership and Retirement Savings Plan

4 OGE Energy Corp. Deferred Compensation Plan

5 Retirement Plan

6 Restoration of Retirement Income Plan

Exhibit 10.33

Amendment Number 1 to the
OGE Energy Corp. Deferred Compensation Plan
(As Amended and Restated Effective January 1, 2005)

OGE Energy Corp., an Oklahoma corporation (the "Company"), by action of its Benefits Oversight Committee taken in accordance with the authority granted to it by Article X of the OGE Energy Corp. Deferred Compensation Plan (As Amended and Restated Effective January 1, 2005), (the "Plan"), hereby amends the Plan in the following respects effective as of January 1, 2005:

1. By deleting Section 2.32 of the Plan and inserting in lieu thereof the following:

"2.3 "Valuation Date" means the last business day of each calendar month and such other dates as may be specified by the Administrator; provided, however, that for purpose of Article VI (other than Section 6.4) only, (i) effective January 1, 2006 through September 30, 2008, Valuation Date shall also mean the last business day of each calendar week and (ii) effective October 1, 2008, Valuation Date shall mean each day the New York Stock Exchange is open."

2. By deleting the first sentence of Section 4.5 of the Plan and inserting in lieu thereof the following:

"The amount of Compensation that a Participant elects to defer under the Plan shall be credited by the Company to the Participant's Account as of the date on which the Compensation would have been payable absent the Deferral Election."

3. By adding a new sentence after the second sentence of Section 6.1 of the Plan as follows:

"Amounts credited to a Participant's Account and applicable subaccounts as set forth in Sections 4.5, 5.1 and 5.2 shall be deemed invested in the applicable assumed investment alternatives (i) prior to October 1, 2008, subject to such rules as the Administrator or its delegate shall determine from time to time and the provisions of Section 6.2 and 6.3 and (ii) on and after October 1, 2008, subject to the provisions of Section 6.2 and 6.3, as of the Valuation Date credited to the Account based on the fair market value of such investment as of such date."

4. By deleting the third and fourth sentence of the first paragraph of Section 6.2 of the Plan and inserting in lieu thereof the following:

"On or before the last business day of each calendar month (or, effective on and after January 1, 2006 and prior to October 1, 2008, on or before 1:00 p.m. Pacific Time on the last business day of each calendar week or effective on an after October 28, 2008, on each Valuation Date or other such time as the Administrator or its delegate shall provide from time to time), a Participant may make a new election, to be effective immediately after the close of business on such last business day or Valuation Date, as the case may be, with respect to the assumed investments in which his or her Account shall be deemed invested in the future. Such new election may, subject to the following sentence, (i) redirect the investment of his or her ending Account balance as of the close of business on such last business day or Valuation Date, as the case may be, among the available assumed investment alternatives and/or (ii) change the assumed investment alternatives in which future contribution credits to be made as of or after the effective date of the election will be deemed invested."

5. By deleting the last sentence of the first paragraph of Section 6.2 of the Plan and inserting in lieu thereof the following:

"The portion of a Participant's Account that is deemed invested in Company common stock or Partnership Units, if any, shall also be credited with deemed dividends or other distributions as of the date on which dividends or other distributions on Company common stock or Partnership Units are paid, and such deemed dividends or other distributions shall be deemed reinvested in Company common stock or Partnership Units, as the case may be, based on the fair market value thereof as provided in Section 6.3."

6. By deleting the third sentence of Section 6.3 of the Plan and inserting in lieu thereof the following:

"Amounts credited to a Participant's Account and applicable subaccounts as set forth in Sections 4.5, 5.1 and 5.2 and dividends or other distributions on Company common stock or Partnership Units under Section 6.2 that are deemed invested in Company common stock or Partnership Units shall be deemed so invested based on the fair market value of a share of Company common stock or Partnership Unit, as the case may be, as reported on the New York Stock Exchange composite tape at the close of business (i) prior to October 1, 2008, on the last business day of the month preceding the date on which the amount is being deemed so invested and (ii) on and after October 1, 2008, on the Valuation Date on or next preceding the date on which the amount is being deemed so invested."

IN WITNESS WHEREOF, the Company has caused this instrument to be signed by a duly authorized officer on this 15th day of December, 2008.

OGE ENERGY CORP.

By: /s/ Carla D. Brockman

Exhibit 10.39

Amendment Number 3 to the
OGE Energy Corp. Deferred Compensation Plan
(As Amended and Restated Effective January 1, 2005)

OGE Energy Corp., an Oklahoma corporation (the "Company"), by action of its Benefits Oversight Committee taken in accordance with the authority granted to it by Article X of the OGE Energy Corp. Deferred Compensation Plan (As Amended and Restated Effective January 1, 2005), as heretofore amended (the "Plan"), hereby further amends the Plan in the following respects effective as of January 1, 2012:

1. By inserting, immediately before the last paragraph of Section 5.3 of the Plan, a new paragraph to read as follows:

Notwithstanding any provision of the Plan, with respect to Matching Credits credited to a Participant's Account on or after January 1, 2012, as adjusted for assumed investment return, the Participant's vested percentage shall be determined in accordance with the following schedule:

Years of Service	Percentage of Matching Credits Vested
Less than 3	0%
3 or more	100%

IN WITNESS WHEREOF, the Company has caused this instrument to be signed by a duly authorized officer on this 18th day of November, 2011.

OGE ENERGY CORP.

By: /s/ Stephen E. Merrill

Exhibit 10.40

Amendment Number 1 to the
OGE Energy Corp. 2008 Stock Incentive Plan

OGE Energy Corp., an Oklahoma corporation (the "Company'), by action of its Board of Directors taken in accordance with the authority granted to it by Section 11 of the OGE Energy Corp. 2008 Stock Incentive Plan (the "Plan"), hereby amends the Plan in the following respects effective as of January 1, 2012:

1. By deleting the second paragraph of Section 3 of the Plan and inserting in lieu thereof the following:

Subject to Section 7(c)(iv), if any shares of Restricted Stock are forfeited for which the participant did not receive any benefits of ownership (as such phrase is construed by the Commission or its staff), or if any Stock Option (and related Stock Appreciation Right, if any) terminates without being exercised, shares subject to such Awards shall again be available for distribution in connection with Awards under the Plan. In the event that (a) any participant delivers shares of Common Stock (i) to pay the exercise price of an Award, or (ii) in satisfaction of any tax withholding requirement, or (b) any other payment made or benefit realized under the Plan is satisfied by the transfer or relinquishment of shares of Common Stock, the number of shares of Common Stock available for Awards under the Plan shall be increased by the number of shares of Common Stock so surrendered, paid or relinquished; provided, however, that, nothwithstanding the foregoing, shares of Common Stock delivered to pay the exercise price of any Stock Option or Stock Appreciation Right, shares of Common Stock delivered in satisfaction of any tax withholding requirement relating to any Stock Option or Stock Appreciation Right and shares of Common Stock otherwise transferred or relinquished in connection with any Stock Option or Stock Appreciation Right shall not increase the number of shares of Common Stock available for Awards under the Plan.

IN WITNESS WHEREOF, OGE Energy Corp. has caused this instrument to be signed in its name by a duly authorized officer on this 15th day of February, 2012.

OGE ENERGY CORP.

By: /s/ Peter B. Delaney_________
Chairman, President and Chief Executive Officer

Exhibit 10.41

OGE Energy Corp.
Director's Compensation

Compensation of non-officer directors of the Company in 2011 included an annual retainer fee of $115,000, of which $42,000 was payable in cash in monthly installments and $73,000 was deposited in the director's account under the Company's Deferred Compensation Plan in December 2011 and converted to 1,392.068 common stock units based on the closing price of the Company's Common Stock on December 2, 2011. Directors who did not serve for the full year received a prorated amount of the annual retainer. All non-officer directors received $1,500 for each Board meeting and $1,500 for each committee meeting attended. The lead director received an additional $15,000 cash retainer in 2011. The chairman of the Audit Committee received an additional $10,000 cash retainer in 2011. The chairmen of the Compensation and Nominating and Corporate Governance Committees received an additional $5,000 annual cash retainer in 2011. Each chairman of a board committee also received a meeting fee of $1,500 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 in 2011.

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 day 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 Company's Deferred Compensation Plan. In 2011, those investment options included a Company Common Stock fund, whose value was determined based on the stock price of the Company's Common Stock, and various money market, bond and equity funds. When an individual ceases to be a director of the Company, all amounts credited under the Company's Deferred Compensation Plan are paid in cash in a lump sum or installments. In certain circumstances, participants may also be entitled to in-service withdrawals from the Company's Deferred Compensation Plan.

In December 2011, the Compensation Committee met to consider director compensation. At that meeting, the Compensation Committee increased the cash portion of the annual retainer for 2012 to $45,600 from $42,000 and increased the fees for each meeting (either in person or by phone) for 2012 to $2,000 from $1,500. The other components of director compensation remained unchanged.

Exhibit 10.42

OGE Energy Corp.
Executive Officer Compensation

Executive Compensation

In December 2011, the Compensation 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 2012. Executive compensation was set by the Compensation Committee after consideration of, among other things, individual performance and market-based data on compensation for executives with similar duties. Payouts of 2012 annual bonus targets and long-term awards are dependent on achievement of specified corporate goals that will be established by the Compensation Committee at a subsequent meeting, and no officer is assured of any payout.

Salary

The Compensation Committee established the base salaries for its senior executive group. The salaries for 2012 for the OGE Energy officers who are expected to be named in the Summary Compensation Table in OGE Energy's 2012 Proxy Statement are as follows:

Executive Officer	2012 Base Salary
Peter B. Delaney, Chairman, President and Chief Executive Officer	$885,000
Sean Trauschke, Vice President and Chief Financial Officer	$478,400
E. Keith Mitchell, President and Chief Operating Officer of Enogex Holdings; President of Enogex LLC	$345,000
Stephen E. Merrill, Chief Operating Officer of Enogex LLC	$306,600

Establishment of 2012 Annual Incentive Awards

As stated above, at its December 2011 meeting, the Compensation 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 2012 corporate goals to be set by the Compensation Committee at a subsequent meeting, to receive from 0 percent to 150 percent of such targeted amount. For 2012, the targeted amount ranged from 55 percent to 90 percent of the approved 2012 base salary for the executive officers in the above table.

Establishment of Long-Term Awards

At its December 2011 meeting, the Compensation 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 Compensation Committee at a subsequent meeting. For 2012, the targeted amount ranged from 100 percent to 240 percent of the approved 2012 base salary for the executive officers in the above table.

Other Benefits

Retirement Benefits. Virtually all of our employees hired before December 1, 2009, including executive officers, are eligible to participate in our Pension Plan and certain employees are eligible to participate in our 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, the supplemental executive retirement plan, which was adopted in 1993, offers supplemental pension benefits to specified lateral hires. Mr. Delaney is the only employee, including executive officers, who participates in the supplemental executive retirement plan. Mr. Delaney's participation in the supplemental executive retirement plan 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 401(k) Plan. Under the 401(k) Plan, participants may contribute each pay period any whole percentage between two percent and 19 percent of their compensation for that pay period. 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 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 Code. The 401(k) Plan was amended in October 2009 whereby eligible employees were provided a choice to select a future retirement benefit combination from the Company's Pension Plan and the Company's 401(k) Plan. For those employees who elected to stay in the Pension Plan (prior to it being amended) and 401(k) Plan (prior to it being amended), the Company matches (other than the "catch-up contributions"), each pay period under the 401(k) Plan, on behalf of each participant, an amount equal to 50 percent of the participant's contributions up to six percent of compensation for participants whose employment or re-employment date occurred before February 1, 2000 and who have less than 20 years of service, as defined in the 401(k) Plan, and an amount equal to 75 percent of the participant's contributions up to six percent of compensation for participants whose employment or re-employment date occurred before February 1, 2000 and who have 20 or more years of service, as defined in the 401(k) Plan. For participants whose employment or re-employment date occurred on or after February 1, 2000 and before December 1, 2009 under the 401(k) Plan (prior to it being amended), the Company contributes 100 percent of the participant's contributions up to six percent of compensation. For participants hired on or after December 1, 2009, the Company contributes, effective January 1, 2010, 200 percent of the participant's contributions up to five percent of compensation. If employees elected not to stay in the Pension Plan (prior to it being amended) and 401(k) Plan (prior to it being amended), effective January 1, 2010, the Company contributes on behalf of each participant, depending on the choice selected, 200 percent of the participant's contributions up to five percent of compensation or 100 percent of the participant's contributions up to six percent of compensation. 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 provides a nonqualified deferred compensation plan which is intended to be an unfunded plan. The deferred compensation plan allows key employees, including all executive officers, to defer compensation above government limitations on 401(k) contributions that apply to the Company's 401(k) Plan and to defer taxation on all earnings on compensation deferred into the plan. Under the terms of the deferred compensation plan, participants have the opportunity to elect to defer each year up to 70 percent of their base salary and up to 100 percent of their annual bonus awards.

The Company matches deferrals to make up for any match lost in the 401(k) Plan because of deferrals to the deferred compensation plan, and to allow for a match that would have been made under the 401(k) Plan on that portion of either the first six percent of total compensation or the first five percent of total compensation, depending on the option the participant elected under the choice provided to eligible employees discussed above, deferred that exceeds the limits allowed in the 401(k) 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. The deferred compensation plan was amended, effective January 1, 2012, to provide for full vesting after three years.

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. In 2011, those investment fund options included a Company Common Stock fund and various money market, bond and equity funds.

Normally, payments under the deferred compensation plan begin within one year after retirement. For these purposes, normal retirement age is 65 and the minimum age to qualify for early retirement is age 55 with at least five years of service. Benefits will be paid, at the election of the participant, either in a lump sum or a stream of annual payments for up to 15 years, or a combination thereof. Participants whose employment terminates before they qualify for retirement 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 percent 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 percent 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 dining and country club memberships for certain executive officers, an annual physical exam for all executive officers and, in the case of Mr. Delaney, use of a Company car. In reviewing the perquisites and the benefits under the supplemental executive retirement plan, 401(k) Plan, Deferred Compensation Plan, Pension Plan and Restoration of Retirement Income Plan, the Compensation Committee sought in 2011 to provide participants with benefits at least commensurate with those offered by other utilities of comparable size.

Change-of-Control Provisions and Employment Agreements. 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 agreements utilize a modified double-trigger because the Board of Directors believed change-of-control payments only should be made if there is a separation of employment following a change-of-control. 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 the 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 form of Employment Agreement is filed as Exhibit 10.28 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 and restricted stock will vest immediately and, for a 60-day period following the change of control, executive officers may surrender their options and receive in return a cash payment equal to the excess of the change of control price (as defined) over the exercise price; all performance units will vest and be paid out immediately in cash as if the applicable performance goals had been satisfied at target levels; and any annual incentive award outstanding for the year in which the participant's termination occurs for any reason, other than cause, within 24 months after the change of control will be paid in cash at target level on a prorated basis.

Exhibit 10.43

Consulting Agreement Between
OGE Energy Corp. and Danny P. Harris

1. **<u>Identification and Parties</u>**. This Consulting Agreement ("Agreement") is entered into by and between Danny P. Harris ("Consultant") and OGE Energy Corp. (the "Company") as of January 1, 2012 (the "Effective Date").

2. **<u>Recitals</u>**. The Company desires to retain Consultant and Consultant desires to be retained upon the terms and conditions set forth in this Agreement.

3. **<u>Term of Agreement</u>**.

9.1. This Consulting Agreement shall commence on the Effective Date.

9.2. This Agreement shall remain in effect for a one (1) year term from January 1, 2012 to January 1, 2013, unless terminated earlier pursuant to Paragraph 6 of this Agreement.

4. **<u>Services</u>**.

4.1. During the term of this Agreement, Consultant shall consult with and advise the Company or its affiliates on specific matters as requested from time to time by the Company's Chief Executive Officer ("CEO") and accepted by Consultant. Consultant shall render such consulting services diligently and in good faith in the interests of the Company and its affiliates. Consultant shall report and be responsible to the CEO or such other person designated in writing to Consultant by the CEO.

4.2. It is the Company's desire that Consultant also continue to serve during the term of this Agreement as a member of the Board of Directors of Enogex Holdings LLC. Notwithstanding anything in this Agreement, the Company and Consultant understand that Consultant can be removed at any time from the Board of Enogex Holdings LLC by OGE Enogex Holdings LLC.

4.3. Consultant shall not be required to devote any minimum number of hours to consulting services under this Agreement nor shall Consultant be guaranteed any number of hours but, as needed, Consultant will make available his time upon reasonable notice during normal business hours to providing services hereunder.

4.4. Consultant has voluntarily sought to do business with the Company, and Consultant represents that entering into this Agreement does not conflict with, or constitute a breach of, the terms of any existing agreement or obligation to which Consultant is a party or by which Consultant is bound.

5. **<u>Compensation</u>**.

5.1. For consulting services performed at the request of the CEO, Consultant shall be paid Four Hundred Dollars ($400.00) an hour. Consultant shall submit monthly invoices with the number of hours worked and a general description of the work performed. Payment to Consultant for consulting services, as approved by the CEO, will be made within thirty (30) days of receipt by the Company of the monthly invoices submitted by Consultant. It is the parties' intent that the total value of services rendered by Consultant under this Agreement not exceed the total amount of Three Hundred Fifty Thousand and 00/100 Dollars ($350,000.00). Therefore, invoices for consulting services that are in excess of Two Hundred Seventy Five Thousand and 00/100 Dollars ($275,000.00) will not be approved for payment. For services performed as a member of the Board of Directors of Enogex Holdings LLC, Consultant shall be paid Seventy-Five Thousand Dollars ($75,000.00) per year. Payment will be made in twelve (12) monthly payments of Six Thousand Two Hundred Fifty Dollars ($6,250.00) each. Payment each month to Consultant will be made by the 10th day of the month following the month in which such services as a board member are rendered.

5.2. In addition, upon submission of the appropriate receipts, Consultant shall be entitled to the reimbursement of the following expenses incurred in the course of performing such services: (i) long-distance telephone charges; (ii) overnight delivery service charges; and (iii) reasonable out-of-pocket travel expenses for travel to locations more than 50 miles from the Company's headquarters at 321 N. Harvey, Oklahoma City, Oklahoma (collectively, "Permitted Expenses").

5.3. Consultant shall be an independent contractor and shall not be entitled to benefits provided by the Company to employees.

5.4. Consultant, as an independent Contractor, will not be provided a permanent office at the Company's headquarters.

6. **Early Termination of Agreement**. The Agreement and the term thereof shall end January 1, 2013, or on the first to occur of the following events:

(i) On fourteen (14) days' advance written notice by Consultant or Company to the other party that the Agreement is cancelled; or

(ii) The death of Consultant; or

(iii) The date as of which the CEO terminates the Agreement because of the inability of Consultant to provide services under this Agreement by reason of Consultant's total disability, as determined by the Company; or

(iv) The date as of which the CEO terminates the Agreement due to the failure of Consultant to perform his obligations under this Agreement in a manner satisfactory to the Company if such failure has continued for thirty (30) days after written notice specifying such failure has been given by the Company to Consultant; except that, if such failure is due to the misconduct, malfeasance, nonfeasance or breach of any provision of this Agreement by Consultant, the date of termination of the Agreement shall be the date written notice of such failure is given to Consultant.

In the event this Agreement is terminated prior to January 1, 2013, all obligations of the Company under Paragraph 5 shall terminate; provided, however, that any amounts to which Consultant is entitled for services rendered prior to the termination of this Agreement but not yet paid as of the termination of this Agreement shall be paid to Consultant as provided in Paragraph 5 and all Permitted Expenses to which Consultant is entitled to reimbursement through the termination of this Agreement shall be paid as provided in Section 5.

7. **Non-Compete**. Consultant agrees that for the time this Agreement is in effect, he will take on other clients only with the prior written approval of the CEO, if such engagement would involve "Competition". For purposes of this Agreement, "Competition" shall mean engaging in or carrying on, directly or indirectly, any enterprise, whether as an advisor, principal, agent, partner, officer, director, employee, stockholder, associate or consultant to any person, partnership, corporation or any other business entity that is principally engaged in the business of the Company or its affiliates in their market areas; provided, however, that "Competition" will not include the mere ownership of 1% or less of the outstanding securities in any enterprise and exercise of rights appurtenant thereto.

8. **Confidentiality**

8.1. "Confidential Information" for purposes of this Agreement shall be defined as all information, knowledge or data relating to the business of the Company or its affiliates, including, but not limited to trade secrets; marketing strategies; financial information; technological and engineering data; formulas; production plans and methods; manufacturing applications and techniques; research and development activities; preferences and identities of customers, vendors, suppliers and prospective customers; vendors and suppliers and sources of business referrals; current, prospective and ongoing business strategies, plans and techniques; computer and other programs, software, devices, methods, techniques, processes and inventions, including, but not limited to, any enhancements thereto; compilations and other materials developed by or on behalf of the Company or its affiliates (whether in written, graphic, audiovisual, electronic or other media, including computer software), which has been and/or will be subject to reasonable efforts to maintain its confidentiality, is not generally known to the public or by competitors of the Company or its affiliates, and which derives its value from remaining undisclosed. Confidential Information also includes information in the above categories of any third party affiliated, associated or doing business with the Company or its affiliates which has been disclosed to the Company or its affiliates in the course of conduct of the Company's or affiliates' business. Confidential Information does not include any information that is in the public domain or otherwise is or becomes publicly available (other than as a result of a wrongful act of Consultant or any agent or employee of the Company or its affiliates).

8.2. Consultant acknowledges that, Consultant has been, and may be in the future, intimately involved with and be privy to Confidential Information which is a valuable asset of the Company and its affiliates and which, if disclosed or used without authorization, would cause irreparable harm to the Company or its affiliates. Consultant acknowledges that the Confidential Information is and will remain the exclusive property of the Company and its affiliates.

8.3. Consultant agrees to hold, at all times during the term of this Agreement and after termination of this Agreement for any reason, all Confidential Information in trust for the benefit of the Company and its affiliates or any third party as described above. Consultant further agrees that he will not, during the term of this Agreement and after termination of this

Agreement for any reason, use in any manner, for the benefit of any individual or entity, or divulge or convey to any other individual or entity, any Confidential Information without the Company's prior written permission, unless: (i) necessary or appropriate to perform his duties under this Agreement as a member of the Board of Directors of Enogex Holdings LLC or (ii) required by legal process; provided that, before making such disclosure in response to legal process, Consultant shall advise the Company and will cooperate fully in any legal action the Company may elect to take in order to attempt to prevent such disclosure.

8.4. Upon termination of this Agreement with the Company for any reason, or at any other time the Company demands, Consultant shall deliver promptly to the Company all Company property then in his possession.

8.5. Consultant agrees that the terms of this Paragraph 8 and the obligations hereunder shall survive termination of the Agreement.

8.6. In the event of a breach by Consultant of any of the provisions of this Paragraph 8, the Company or its affiliates may, in addition to any other rights and remedies existing in their favor, apply to any court of law or equity of competent jurisdiction for specific performance and/or injunctive or other relief in order to enforce or prevent any violations of the provisions hereof.

9. **General Provisions**.

9.1. This Agreement constitutes the entire agreement between the Company and Consultant with respect to the performance of consulting and Board services and supersedes all prior and contemporaneous agreements, representations and understandings, oral or written, regarding such matters between the parties.

9.2. This Agreement shall be governed by and construed in accordance with the laws of the State of Oklahoma, without regard to conflicts of law principles.

9.3. Any dispute, claim or controversy of any kind whatsoever between Consultant and the Company, shall be settled by final and binding arbitration in Oklahoma City, Oklahoma, by the American Arbitration Association (the "AAA"), pursuant to the AAA's Commercial Arbitration Rules and procedures that are then in effect. The parties to this Agreement and all who claim under them shall be conclusively bound by the determination of any arbitrator, and only have the right to have any decision or award rendered in accordance with this Paragraph entered as a judgment in a court of the State of Oklahoma or any other court of competent jurisdiction. Any claim by a party to this Agreement must be raised within six (6) months of the date of the knowledge by the party of such claim, or within the time provided by law, whichever is earlier.

9.4. The captions and paragraph numbers appearing in this Agreement are inserted for convenience and in no way define, limit, construe or describe the scope or intent of the provisions of this Agreement.

9.5. No waiver of any breach of any term or provision of this Agreement shall be construed to be, nor shall be, a waiver of any other breach of this Agreement. No waiver shall be binding unless in writing and signed by the party waiving the breach.

9.6. This Agreement has been reviewed by the parties and the parties have had an opportunity to have it reviewed by their respective attorneys. The parties have had a sufficient opportunity to consider and negotiate the contents of this Agreement.

9.7. This Agreement may be amended, modified, or supplemented only by a written agreement, executed by both parties to this Agreement.

9.8. The provisions of this Agreement are severable and, in the event that any provision hereof shall be found by any court to be unenforceable, in whole or in part, the remainder of this Agreement shall nonetheless remain enforceable and binding upon the Company and Consultant.

9.9. All notices or other communications provided for in this Agreement shall be in writing and shall be deemed to have been given if delivered by hand or by a nationally recognized overnight delivery service to the parties at the following addresses:

CONSULTANT:

Danny P. Harris
6401 N.E. 105th
Oklahoma City, Oklahoma 73151

COMPANY:

Peter B. Delaney
Chief Executive Officer
OGE Energy Corp.
321 N. Harvey
Oklahoma City, OK 73102

Either party wishing to change the address to which notice or other communications under this Agreement shall be sent shall give written notice of such change to the other party.

9.10. The parties hereby acknowledge and agree that (i) in performing his obligations hereunder, Consultant will be acting exclusively as an independent contractor, and (ii) they do not intend, and will not hold out or permit the assertion by any third party, that there exists any partnership, agency, joint venture, common undertaking for a profit or other relationship between the parties other than that of independent contractor.

9.11. This Agreement shall inure to the benefit of and be binding upon the Company, its successors and assigns, including, without limitation, any person, partnership, corporation or other entity which may acquire all or substantially all of the Company's assets and business or into or with which the Company may be merged or consolidated, and upon Consultant and his personal or legal representatives, executors, administrators, successor, heirs, distributees or legatees. This Agreement may not be assigned by Consultant in whole or in part without prior written consent of the Company.

9.12. The Company may withhold from any amounts payable under this Agreement all federal, state, city or other taxes the Company is required to withhold pursuant to any law or government regulation or ruling.

9.13. For purposes of this Agreement, the term "affiliate" means with respect to the Company or any other entity, an entity that directly, or indirectly through one or more intermediaries, controls, is controlled by, or is under common control with the Company or such other entity.

IN WITNESS WHEREOF, the parties have executed this Agreement as of this 1st day of December, 2011.

CONSULTANT:

By: /s/ Danny P. Harris
Danny P. Harris

COMPANY:

By: /s/ Peter B. Delaney
Peter B. Delaney, Chief Executive Officer

Exhibit 12.01

OGE Energy Corp.
Ratio of Earnings to Fixed Charges

Year ended December 31 *(In millions)*	2007	2008	2009	2010	2011
Earnings:					
Pre-tax income	$ 361.9	$ 338.6	$ 382.2	$ 461.4	$ 524.3
Add: Fixed charges	97.6	130.0	154.5	150.1	161.8
Subtotal	459.5	468.6	536.7	611.5	686.1
Subtract:					
Allowance for borrowed funds used during construction	4.0	4.0	8.3	5.5	10.4
Other capitalized interest	0.9	3.5	6.3	2.5	8.7
Total earnings	454.6	461.1	522.1	603.5	667.0
Fixed Charges:					
Interest on long-term debt	88.7	106.6	143.6	141.8	154.8
Interest on short-term debt and other interest charges	6.4	21.0	8.4	5.9	5.2
Calculated interest on leased property	2.5	2.4	2.5	2.4	1.8
Total fixed charges	$ 97.6	$ 130.0	$ 154.5	$ 150.1	$ 161.8
Ratio of Earnings to Fixed Charges	4.66	3.55	3.38	4.02	4.12

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
OGE Enogex Holdings LLC	Delaware	100.0
Enogex Holdings LLC	Delaware	81.3
Enogex LLC	Delaware	81.3
Enogex Gathering & Processing LLC	Oklahoma	81.3
OGE Energy Resources LLC	Oklahoma	81.3
Enogex Products LLC	Oklahoma	81.3
Enogex Gas Gathering LLC	Oklahoma	81.3

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. 333-178093) pertaining to the dividend reinvestment and stock purchase plan and the Registration Statement (Form S-3ASR No. 333-166572) pertaining to common stock and preferred share purchase rights and debt securities, of our reports dated February 16, 2012, 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, 2011.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 16, 2012

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, 2011; 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, SEAN TRAUSCHKE 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 15th day of February, 2012.

Peter B. Delaney, Chairman, Principal Executive Officer and Director	/s/ Peter B. Delaney
James H. Brandi, Director	/s/ James H. Brandi
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
Judy R. McReynolds, Director	/s/ Judy R. McReynolds
Leroy C. Richie, Director	/s/ Leroy C. Richie
Sean Trauschke, Principal Financial Officer	/s/ Sean Trauschke
Scott Forbes, Principal Accounting Officer	/s/ Scott Forbes

STATE OF OKLAHOMA)
) SS
COUNTY OF OKLAHOMA)

On the date indicated above, before me, Kelly Hamilton-Coyer, Notary Public in and for said County and State, the above named directors and officers of OGE ENERGY CORP., an Oklahoma corporation, known to me to be the persons whose names are subscribed to the foregoing instrument, 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 15th day of February, 2012.

/s/ Kelly Hamilton-Coyer
By: Kelly Hamilton-Coyer
Notary Public

My commission expires:
July 6, 2013

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 16, 2012

/s/ Peter B. Delaney

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

Exhibit 31.01

CERTIFICATIONS

I, Sean Trauschke, 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 16, 2012

/s/ Sean Trauschke

Sean Trauschke
Vice President and Chief Financial Officer

Exhibit 32.01

Certification Pursuant to 18 U.S.C. Section 1350
As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of the Company on Form 10-K for the period ended December 31, 2011, 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 16, 2012

/s/ Peter B. Delaney

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

/s/ Sean Trauschke

Sean Trauschke
Vice President and Chief Financial Officer

Exhibit 99.01

OGE Energy Corp. Cautionary Factors

The Private Securities Litigation Reform Act of 1995 provides a "safe harbor" for forward-looking statements to encourage such disclosures without the threat of litigation providing those statements are identified as forward-looking and are accompanied by meaningful, cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Forward-looking statements have been and will be made in written documents and oral presentations of the Company. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used in the Company's documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "intend", "objective", "plan", "possible", "potential", "project" and similar expressions are intended to identify forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause the Company's actual results to differ materially from the forward-looking statements include, but are not limited to, the following, by segment:

Consolidated (including Electric Utility, Natural Gas Transportation and Storage, Natural Gas Gathering and Processing and Natural Gas 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 PRM 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, access to the commercial paper markets, actions of rating agencies and their impact on capital expenditures and 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 Financial Accounting Standards Board, the Securities and Exchange Commission, 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 restrict or change 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 noncontrolling interests which would limit the Company's ability to control the development or operation of an investment;
- Increased pension and healthcare costs;
- Costs and other effects of legal and administrative proceedings, settlements, investigations, claims and matters, including but not limited to those described in Note 16 of Notes to Consolidated Financial Statements in this Form 10-K;
- Technological developments, changing markets and other factors that result in competitive disadvantages and create the potential for impairment of existing assets;
- The cost of protecting assets against, or damage due to, terrorism or cyber attacks; and
- Other business or investment considerations that may be disclosed from time to time in the Company's Securities and Exchange Commission filings or in other publicly disseminated written documents.

Electric Utility Segment

- Increased competition in the utility industry, including effects of decreasing margins as a result of competitive pressures; industry restructuring initiatives; transmission system operation and/or administration initiatives; recovery of investments made under traditional regulation; nature of competitors entering the industry; retail wheeling; a new pricing structure; and former customers entering the generation market;
- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related damage; unscheduled generation outages, unusual maintenance or repairs; unanticipated changes to fossil fuel, natural gas or coal supply costs or availability due to higher demand, shortages, transportation problems or other developments; environmental incidents; or electric transmission or gas pipeline system constraints;
- Rate-setting policies or procedures of regulatory entities, including environmental externalities;
- Approval of future regulatory filings with the OCC or the APSC;
- Whether OG&E can successfully implement its Smart Grid program to install meters for its customers and integrate the Smart Grid meters with its customer billing and other computer information systems; and
- Discontinuance of accounting principles for certain types of rate-regulated activities.

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.