OGE ENERGY CORP.
Form 10-K
February 27, 2013

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, 2012
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 Exchange Act).
£ Yes R No
At June 29, 2012, 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 $5,076,608,581 based on the number of shares held by non-affiliates (98,022,950) and the reported closing market price of the common stock on the New York Stock Exchange on such date of $51.79.
At January 31, 2013, there were 98,790,726 shares of common stock, par value $0.01 per share, outstanding.
DOCUMENTS INCORPORATED BY REFERENCE
The Proxy Statement for the Company's 2013 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, 2012

TABLE OF CONTENTS

i

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
Chesapeake	Chesapeake Energy Marketing, Inc. and Chesapeake Exploration L.L.C.
Code	Internal Revenue Code of 1986
Company	OGE Energy, collectively with its subsidiaries
Cordillera	Cordillera Energy Partners III, LLC
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
Dry Scrubbers	Dry flue gas desulfurization units with spray dryer absorber
EBITDA	Enogex Holdings earnings before interest, taxes, depreciation and amortization
EER	Enogex Energy Resources LLC, wholly-owned subsidiary of Enogex LLC (prior to June 30, 2012, the legal name was OGE Energy Resources LLC)
Enogex	OGE Holdings, collectively with its subsidiaries
Enogex Holdings	Enogex Holdings LLC, the parent company of Enogex LLC and a majority-owned subsidiary of OGE Holdings
Enogex LLC	Enogex LLC, collectively with its subsidiaries
EPA	U.S. Environmental Protection Agency
Federal Clean Water Act	Federal Water Pollution Control Act of 1972, as amended
FERC	Federal Energy Regulatory Commission
FIP	Federal implementation plan
GAAP	Accounting principles generally accepted in the United States
MATS	Mercury and Air Toxics Standards
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
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
PSO	Public Service Company of Oklahoma

QF	Qualified cogeneration facilities
QF contracts	Contracts with QFs and small power production producers
Restoration of Retirement Income Plan	Supplemental retirement plan to the Pension Plan
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

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 as well as inflation rates and monetary fluctuations;
- 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;
- the cost of protecting assets against, or damage due to, terrorism or cyber attacks and other catastrophic events;
- 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 three business segments: (i) electric utility, (ii) natural gas transportation and storage and (iii) natural gas gathering and processing. 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 and storing 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. During the third quarter of 2012, the operations and activities of EER were fully integrated with those of Enogex through the creation of a new commodity management organization. This new organization is intended to facilitate the execution of Enogex's strategy through an enhanced focus on asset optimization and active management of its growing natural gas, NGLs and condensate positions. The operations of EER, including asset management activities, have been included in the natural gas transportation and storage segment and have been restated for all prior periods presented. Enogex's operations are now organized into two business segments: (i) natural gas transportation and storage and (ii) natural gas gathering and processing. At December 31, 2012, OGE Energy indirectly owns a 79.9 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 focusing on safety, efficiency, reliability, customer service and risk management. 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.

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 expects to maintain a diverse generation portfolio while remaining environmentally responsible. 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 as well as allow customers to monitor and manage their energy usage, which should help reduce demand during critical peak times, resulting in lower capacity requirements. 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. The Smart Grid program also provides benefits to OG&E, including more efficient use of its resources and access to increased information about customer usage, which should enable OG&E to have better distribution system planning data, better response to customer usage questions and faster detection and restoration of system outages. 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.

Enogex's business plan entails growing its businesses and providing attractive financial returns through efficient operations and effective commercial management of its assets. Enogex also plans to capture growth opportunities through expansion projects, in creased utilization of existing assets and through acquisitions (including joint ventures) in and around its footprint and attracting new customers. 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.

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. 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. During 2012, one other community 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 2012 from sales in Oklahoma and the remainder from sales in Arkansas.

OG&E's system control area peak demand in 2012 was 7,000 MWs on August 1, 2012. OG&E's load responsibility peak demand was 6,459 MWs on August 1, 2012. As reflected in the table below and in the operating statistics that follow, there were 28.0 million MWH system sales in 2012, 28.5 million MWH system sales in 2011 and 27.6 million MWH system sales in 2010. Variations in system sales for the three years are reflected in the following table:

Year ended December 31	2012	2012 vs. 2011 Decrease	2011	2011 vs. 2010 Increase	2010
System sales - millions of MWHs	28.0	(1.8)%	28.5	3.3%	27.6

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	2012	2011	2010
ELECTRIC ENERGY (Millions of MWH)			
Generation (exclusive of station use)	26.3	26.7	25.6
Purchased	5.0	4.9	4.7
Total generated and purchased	31.3	31.6	30.3
OG&E use, free service and losses	(1.9)	(2.1)	(2.2)
Electric energy sold	29.4	29.5	28.1
ELECTRIC ENERGY SOLD (Millions of MWH)			
Residential	9.1	9.9	9.6
Commercial	7.0	6.9	6.7
Industrial	4.0	3.9	3.8
Oilfield	3.3	3.2	3.1
Public authorities and street light	3.3	3.2	3.0
Sales for resale	1.3	1.4	1.4
System sales	28.0	28.5	27.6
Off-system sales	1.4	1.0	0.5
Total sales	29.4	29.5	28.1
ELECTRIC OPERATING REVENUES (In millions)			
Residential	$878.0	$943.5	$894.8
Commercial	523.5	531.3	521.0
Industrial	206.8	216.0	212.5
Oilfield	163.4	165.1	162.8
Public authorities and street light	202.4	207.4	200.8
Sales for resale	54.9	65.3	65.8
System sales revenues	2,029.0	2,128.6	2,057.7
Off-system sales revenues	36.5	36.2	21.7
Other	75.7	46.7	30.5
Total operating revenues	$2,141.2	$2,211.5	$2,109.9
ACTUAL NUMBER OF ELECTRIC CUSTOMERS (At end of period)			
Residential	683,214	675,806	670,309
Commercial	88,772	87,480	86,496
Industrial	2,957	2,991	3,020
Oilfield	6,426	6,451	6,418
Public authorities and street light	16,695	16,374	16,264
Sales for resale	46	44	51
Total	798,110	789,146	782,558
AVERAGE RESIDENTIAL CUSTOMER SALES			
Average annual revenue	$1,292.11	$1,401.84	$1,339.81
Average annual use (kilowatt-hour)	13,477	14,738	14,304
Average price per kilowatt-hour (cents)	$9.59	$9.51	$9.37

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 2012, 87 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight percent to the APSC and five 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 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 called 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 Energy built, owns and operates the wind farm and OG&E purchases the electric output. On February 22, 2012, OG&E, the Attorney General and the Public Utility Division of the OCC signed a settlement agreement whereby the stipulating parties requested that the OCC issue an order approving the agreement for electric service with Oklahoma State University. On March 12, 2012, OG&E received an order from the OCC approving the settlement agreement. Pursuant to the terms of the power purchase agreement between OG&E and NextEra Energy, OG&E has been purchasing the electric output of the wind farm since November 2012 and uses that power to provide service to Oklahoma State University and its other retail customers. The wind farm was fully in service in December 2012.

OG&E SPP Transmission 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 below.

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 originating at OG&E's existing Sooner 345 kilovolt substation and proceeding 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 connects to the companion line constructed in Kansas by Westar Energy. The transmission line was placed in service in April 2012. The total capital expenditures associated with this project were $45 million.

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 extends 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 transmission line was completed in April 2012. The total capital expenditures associated with this project were $157 million.

As discussed below, the OCC approved a settlement agreement in OG&E's 2011 Oklahoma rate case filing that included an expedited procedure for recovering the costs of the two projects. On July 31, 2012, OG&E filed an application with the OCC requesting an order authorizing recovery for the two projects through the SPP transmission systems additions rider. On October 2, 2012, all parties signed a settlement agreement in this matter which stated: (i) the parties agree not to oppose requested relief sought by OG&E, (ii) OG&E will host meetings to discuss the SPP's transmission planning process, including any future transmission projects for which OG&E has received a notice to construct from the SPP, and (iii) there will be opportunities for parties to provide input related to transmission planning studies that the SPP performs to identify future transmission projects. On October 25, 2012, the OCC issued an order approving the settlement agreement and granting OG&E cost recovery for the two projects. OG&E initiated cost recovery beginning with the first billing cycle in November 2012.

OG&E 2011 Oklahoma Rate Case Filing

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 requested a return on equity of 11.0 percent based on a common equity percentage of 53.0 percent. In its application, OG&E requested recovery of 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 July 2, 2012, OG&E and other parties associated with its rate increase reached a settlement agreement in this matter. On July 9, 2012, the OCC issued an order approving the settlement agreement in this matter. Key terms of the settlement agreement included: (i) an annual net increase of approximately $4.3 million in OG&E's rates to its Oklahoma retail customers, (ii) OG&E's Oklahoma retail authorized return on equity of 10.2 percent, (iii) the rate of return under various recovery riders previously approved by the OCC, including riders for OG&E's smart grid implementation and Crossroads wind farm, is based on OG&E's actual debt and equity ratios as reflected in OG&E's application and a 10.2 percent return on equity, (iv) depreciation rates were implemented in the same month new customer rates went into effect, (v) the pension and postretirement medical cost tracker remains in effect, (vi) a procedure was established to expedite the recovery of the cost of specified high-voltage transmission projects and (vii) extension of funding for OG&E's system hardening program. OG&E expects the impact of the rate increase on its customers and service territory to be minimal as the rate increase will be more than offset by lower fuel costs attributable to prior fuel over recoveries from lower than forecasted fuel costs. OG&E implemented the new rates effective in early August.

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. On August 3, 2011, the APSC issued an order in this matter approving the settlement agreement. On November 5, 2012, OG&E filed a revised smart grid recovery rider rate schedule. On December 13, 2012, the APSC issued an order in this matter approving the revised smart grid recovery rider to be effective beginning with the first billing cycle in January 2013 through December 2013. OG&E began recovering the 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. The APSC also found that the prudence of OG&E’s smart grid expenditures will be determined in OG&E's next Arkansas rate case and that revenues collected under the rider are subject to refund, with interest, only in the event that the APSC determines that OG&E's smart grid expenditures were not prudent. The costs recoverable from Oklahoma customers for system-wide deployment of smart grid technology and implementing the smart grid pilot program were 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 in OG&E's next general rate case. This project was completed in late 2012 and the smart grid project costs did not exceed $366.4 million.

OG&E Demand and Energy Efficiency Program Filing

On July 2, 2012, OG&E filed an application with the OCC requesting approval of OG&E's 2013 demand portfolio, the authorization to recover the program costs, lost revenues associated with any achieved energy, demand savings and performance based incentives through the demand program rider and the recovery of costs associated with research and development investments. On July 16, 2012, OG&E filed an amended application which modified various calculations to reflect the rate of return authorized by the OCC in OG&E's 2011 rate case order and provided for consideration of a peak time rebate program. On December 20, 2012, the OCC approved a settlement with all parties in this matter. Key terms of the settlement included (i) approval of the program budgets proposed by OG&E and an additional amount of approximately $7 million over the three-year period for the energy efficiency programs, (ii) approval of OG&E’s proposed Demand Program Rider tariff, (iii) the recovery through the Demand Program Rider of the increased program costs and the net lost revenues, incentives and research and development investments requested by OG&E, with the exception of lost revenues resulting from the Integrated Volt Var Control program (automated intelligence to control voltage and power on the distribution lines) and incentives for the SmartHours® and Integrated Volt Var Control demand response programs, (iv) recovery of the program costs on a levelized basis over the three-year period, (v) consideration of implementing a peak time rebate program in 2015 and (vi) the periodic filing of additional reports. The Demand Program Rider became effective on January 1, 2013.

OG&E Fuel Adjustment Clause Review for Calendar Year 2010

The OCC routinely reviews the costs recovered from customers through OG&E’s fuel adjustment clause. On August 19, 2011, the OCC Staff filed an application to review OG&E’s fuel adjustment clause for calendar year 2010, including the prudence of OG&E’s electric generation, purchased power and fuel procurement costs. OG&E responded by filing direct testimony and the minimum filing review package on October 18, 2011. On September 26, 2012, the administrative law judge recommended that the OCC find that for the calendar year 2010 OG&E's generation, purchase power and fuel procurement processes and costs, including the cost of replacement power for the Sooner 2 outage, were prudent and no disallowance (as discussed below) for any of these expenses is warranted. On January 31, 2013, the OCC issued an order approving the administrative law judge's recommendation. Previously, the Oklahoma Industrial Energy Consumers recommended that the OCC disallow recovery of approximately $44 million of costs previously recovered through OG&E's fuel adjustment clause. These recommendations were based on allegations that OG&E's lower cost coal-fired generation was underutilized, that OG&E failed to aggressively pursue purchasing power at a cost lower than its marginal cost of generation and that OG&E should be found imprudent related to an unplanned outage at OG&E's Sooner 2 coal unit in November and December 2010. Previously, the OCC Staff recommended approval of OG&E's actions related to utilization of coal plants and practices related to purchasing power but recommended that OG&E refund $3 million to customers because of the Sooner 2 outage.

Pending Regulatory Matters

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 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. These changes to the "right of first refusal" apply 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 were filed on November 13, 2012.

OGE Energy cannot, at this time, determine the precise impact of Order No. 1000 on OG&E. OG&E has filed a petition for review in the D.C. Circuit relating to the same matter. 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.

OG&E Market-Based Rate Authority

On June 29, 2012, OG&E filed its triennial market power update with the FERC to retain its market-based rate authorization in the SPP's energy imbalance service market but to surrender its market-based rate authorization for any market-based rate sales outside the SPP's energy imbalance service market. A FERC order is pending.

OG&E Fuel Adjustment Clause Review for Calendar Year 2011

On July 31, 2012, the OCC Staff filed an application for a public hearing to review and monitor OG&E's application of the 2011 fuel adjustment clause and for a prudence review of OG&E's electric generation, purchased power and fuel procurement processes and costs in calendar year 2011. OG&E filed the necessary information and documents needed to satisfy the OCC's minimum filing requirement rules on October 1, 2012. On December 19, 2012, witnesses for the OCC Staff filed responsive testimony recommending that the OCC approve OG&E's fuel adjustment clause costs and recoveries for the calendar year 2011 and recommending that the OCC find that OG&E's electric generation, purchased power, fuel procurement and other fuel related practices, policies and decisions during calendar year 2011 were fair, just and reasonable and prudent. The Oklahoma Industrial Energy Consumers filed a statement of position on December 19, 2012 and did not challenge OG&E's application of its fuel adjustment clause or prudency. The Oklahoma Industrial Energy Consumers reserved its right to file rebuttal testimony, cross examine witnesses and amend its statement of position should circumstances change or additional information becomes available in the course of this proceeding. On January 7, 2013, the Oklahoma Attorney General filed a statement of position stating that after reviewing the case information the Attorney General has no reason at this time to dispute the findings of the OCC Staff. A hearing in this matter is scheduled for April 4, 2013.

OG&E Crossroads Wind Farm

As previously reported, OG&E signed memoranda of understanding in February 2010 for approximately 197.8 MWs of wind turbine generators and certain related balance of plant engineering, procurement and construction services associated with the Crossroads wind farm. Also as part of this project, on June 16, 2011, OG&E entered into an interconnection agreement with the SPP for the Crossroads wind farm which allowed the Crossroads wind farm to interconnect at 227.5 MWs. On August 31, 2012, OG&E filed an application with the APSC requesting approval to recover the Arkansas portion of the costs of the Crossroads wind farm through a rider until such costs are included in OG&E's base rates as part of its next general rate proceeding. On December 14, 2012, the APSC Staff filed testimony recommending that the APSC find that the Crossroads wind farm is in the public interest and that it approve interim recovery through the Energy Cost Recovery Rider effective August 31, 2012. OG&E concurred with the APSC Staff’s recommendations. On January 16, 2013, the APSC granted a motion made by OG&E and the APSC Staff to cancel the hearing previously scheduled and issue an order based on the filed record. On February 22, 2013, the APSC directed OG&E to respond to two questions in order to complete the record upon which they may rule. OG&E believes it is reasonable to expect a final order from the APSC by the end of the first quarter.

OG&E Fuel Adjustment Clause Review for Calendar Year 2009 Related to Enogex Gas Transportation and Storage Agreement

As previously reported, under the terms of a settlement agreement reached in 2011 regarding the prudency of OG&E's fuel adjustment clause for 2009, OG&E agreed to hire a third party expert to evaluate its prospective gas transportation and storage needs and to identify options for meeting those needs. Upon completion of the third party evaluation, OG&E agreed to file a cause to address the third party's evaluation, recommendations and conclusions. On January 31, 2013, OG&E filed a cause that included OG&E's response to the final evaluations and conclusions of the third party consultant, Black & Veatch, and OG&E's assessment of transportation and storage needs for the next three to five years.

Also, as part of this matter, on August 9, 2012, OG&E filed an application with the OCC requesting: (i) an order finding that a one-year extension to April 30, 2014 of OG&E's gas transportation and storage agreement with Enogex is prudent, (ii) a waiver of the OCC's competitive procurement rules and (iii) finding that the one-year extension of the gas transportation and storage agreement complies with the OCC's affiliate transaction rules. On September 14, 2012, OG&E filed a settlement agreement in which all parties to this matter agreed to the one-year extension of the Enogex contract and cost recovery from ratepayers at the rates currently in effect. On October 25, 2012, the OCC issued an order approving the settlement agreement.

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, 2012 and 2011, OG&E had regulatory assets of $537.6 million and $523.9 million, respectively, and regulatory liabilities of $386.2 million and $276.4 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 OG&E 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. Under OG&E's Smart Grid enabled SmartHours® programs, "time-of-use" and "variable peak pricing" rates offer customers the ability to save on their electricity bills by shifting some of the electricity consumption to times when demand for electricity and costs are at their lowest. 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 monthly 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 "day-ahead price" and "flex price" rate options which allow participating customers to adjust their electricity consumption based on price signals received from OG&E. The prices for the "day-ahead price" and "flex price" rate options are 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 provide OG&E with flexibility to provide targeted programs for load management to public schools and their unique usage patterns.

OG&E also provides service level, seasonal and time period fuel charge differentiation that allows customers to pay fuel costs that better reflect the underlying costs of providing electric service. Lastly, OG&E has 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 2012, 52 percent of the OG&E-generated energy was produced by coal-fired units, 42 percent by natural gas-fired units and six percent by wind-powered units. Of OG&E's 6,807 total MW capability reflected in the table under Item 2. Properties, 3,816 MWs, or 56 percent, are from natural gas generation, 2,542 MWs, or 37 percent, are from coal generation and 449 MWs, or seven 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)	2012	2011	2010	2009	2008
Natural gas	2.930	4.328	4.638	3.696	8.455
Coal	2.310	2.064	1.911	1.747	1.153
Weighted average	2.437	2.897	3.012	2.474	3.337

The decrease in the weighted average cost of fuel in 2012 as compared to 2011 was primarily due to lower natural gas prices. 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. 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 2,542 MWs, are designed to burn low sulfur western sub-bituminous coal. OG&E has contracted for approximately 60 percent of its forecasted annual coal usage via multi-year contracts that expire in 2015 and the remainder of its forecasted 2013 usage via one-year contracts that expire in 2013. In 2012, OG&E purchased 8.5 million tons of coal from various Wyoming suppliers. The combination of all coal has a weighted average sulfur content of 0.23 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 SO_2 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 entered into multiple month term natural gas contracts for 26.1 percent of its 2013 annual forecasted natural gas requirements. Additional gas supplies to fulfill OG&E's remaining 2013 natural gas requirements will be acquired through additional requests for proposal in early to mid-2013, 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, 2012, OG&E had 1.5 million MMBtu's in natural gas storage valued at $4.6 million.
Wind
OG&E's current wind power portfolio includes: (i) the 120 MW Centennial wind farm, (ii) the 101 MW OU Spirit wind farm, (iii) the 227.5 MW 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, (vi) access to up to 130 MWs of electricity generated at a wind farm in Dewey County, Oklahoma from a 20-year contract OG&E entered into with Edison Mission Energy that expires in 2030 and (vii) access to up to 60 MWs of electricity generated at a wind farm near Blackwell, Oklahoma from a 20-year contract OG&E entered into with NextEra Energy that expires in 2032.

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 and storing 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. During the third quarter of 2012, the operations and activities of EER were fully integrated with those of Enogex through the creation of a new commodity management organization. The operations of EER, including asset management activities, have been included in the natural gas transportation and storage segment and have been restated for all prior periods presented. Enogex's operations are now organized into two business segments: (i) natural gas transportation and storage and (ii) natural gas gathering and processing.

On October 5, 2010, OGE Energy entered into an investment agreement with the ArcLight group, whereby the ArcLight group contributed $183,150,000 in exchange for a membership interest in Enogex Holdings. As a result of this transaction, the ArcLight group acquired an indirect interest in Enogex LLC and OGE Energy retained an indirect 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 disproportionate contributions by the ArcLight group, at December 31, 2012, OGE Energy indirectly owns a 79.9 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 is based on the equity value of Enogex Holdings. Subject to certain adjustments, including for material acquisitions, the equity value is calculated as 9.0 or 9.5 times trailing 12-month EBITDA, 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.

Natural Gas Transportation and Storage

General

Enogex owns and operates approximately 2,284 miles of intrastate natural gas transportation pipelines in Oklahoma with 2.08 TBtu/d of average daily throughput in 2012. 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 from 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 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, 2012, Enogex was connected to 13 third-party natural gas pipelines and had 63 interconnect points. These third-party natural gas pipelines include ANR Pipeline, CenterPoint Energy Gas Transmission Co., El Paso Natural Gas Pipeline, Gulf Crossing Pipeline Company LLC, MEP, Natural Gas Pipeline Company of America, Northern Natural Gas Company, Oneok Gas Transmission, Ozark Gas Transmission, L.L.C., Panhandle Eastern Pipe Line, Postrock KPC Pipeline, LLC, Southern Star Central Gas Pipeline (formerly Williams Central) and Western Farmers Electric Cooperative. Further, Enogex is connected to 37 end-user customers, including 15 natural gas-fired electric generation facilities in Oklahoma.

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 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 gas transportation and storage 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 stated term of the PSO contract expired January 1, 2013, 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 January 1, 2013, the PSO contract will remain in effect at least through January 1, 2014. 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, 2013, the OG&E contract will remain in effect at least through April 30, 2014. 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 2012, 2011 and 2010, revenues from Enogex's firm intrastate natural gas transportation and storage contracts were $131.5 million, $130.7 million and $116.6 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 27 percent of Enogex's consolidated gross margin in 2012, 30 percent in 2011 and 28 percent in 2010.

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, fuel oils and wind power. 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.

Completed Regulatory Matters

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. On July 6, 2012, Enogex submitted a compliance filing to synchronize the 2011 fuel filing with the revised statement of operating conditions filed on May 31, 2012 in compliance with the FERC's order approving Enogex's 2011 Section 311 rate case settlement. In October 2012, the FERC accepted Enogex's proposed zonal fuel percentages.

Enogex 2012 Fuel Filing

On February 24, 2012, Enogex submitted its annual fuel filing to establish the fixed fuel percentages for its East Zone and West Zone for the 2012 fuel year (April 1, 2012 through March 31, 2013). On July 6, 2012, Enogex submitted a compliance filing to synchronize the 2012 fuel filing with the revised statement of operating conditions filed on May 31, 2012 in compliance with the FERC's order approving Enogex's 2011 Section 311 rate case settlement. In October 2012, the FERC accepted Enogex's proposed zonal fuel percentages.

Enogex Storage Statement of Operating Conditions Filing

On August 31, 2010, Enogex filed a new statement of operating conditions applicable to storage services with the FERC 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. On December 7, 2012, the FERC issued an order approving Enogex's revised storage statement of operating conditions, effective August 31, 2010.

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. On January 10, 2012, Enogex filed a settlement agreement with the FERC. On May 4, 2012, the FERC issued an order approving the settlement agreement in this matter, subject to the submission of a compliance filing to place the settlement rates into effect as of March 1, 2011, which compliance filing was subsequently filed on May 31, 2012. The FERC also requested that Enogex file a revised statement of operating conditions, which was subsequently filed on May 31, 2012. As part of the settlement agreement in this matter, Enogex made refunds of $0.2 million to affected customers on June 15, 2012 and submitted a report to the FERC on July 6, 2012 showing the refund payment calculation. On February 21, 2013, the FERC issued an order approving the refund report.

Recent System Expansions

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

In 2006, Enogex entered into a firm capacity 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 capacity agreement is currently 272 MMcf/d, with the quantity subject to being increased by mutual agreement pursuant to the capacity agreement. In addition to MEP's capacity agreement, 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 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.

14

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.

Natural Gas Gathering and Processing

General

Enogex provides well connect, gathering, measurement, treating, dehydration, compression and processing services for various types of natural gas 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 extracted that meets transmission pipeline and commercial quality specifications. Enogex is active in the extraction and marketing of NGLs from natural gas it processes. 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 6,640 miles of intrastate natural gas gathering pipelines in Oklahoma and Texas with 1.41 TBtu/d of average daily gathered volumes in 2012. Enogex owns and operates nine natural gas processing plants, with a current total inlet capacity of 1,305 MMcf/d and has contracted to have access to up to 90 MMcf/d of capacity in three 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 for the nine processing plants that Enogex owns. In 2012, Enogex extracted and sold 867 million gallons of NGLs.

Enogex also has a 50 percent interest in Atoka, which previously 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.

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, 2012, these arrangements accounted for 35 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, 2012, Enogex's percent-of-proceeds and percent-of-liquids processing arrangements accounted for 16 percent and 28 percent, respectively, 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, 2012, these arrangements accounted for 21 percent of Enogex's natural gas processed volumes.

Total processable volumes during 2012 were 1.00 Tbtu/d. Processable volumes are the natural gas production that are on Enogex's gathering systems that are available to be processed, some of which is moved off of the system and is not processed under one of Enogex's processing agreements. Processable volumes include condensate volumes which are captured in the gathering pipeline and therefore not included in plant inlet 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 natural gas 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. As a result, Enogex has recorded $7.1 million in Deferred Revenues on the Company's Consolidated Balance Sheet at December 31, 2012, which are expected to be recognized based on the estimated average fee per MMBtu processed by the end of 2014.

On January 2, 2013, Enogex and one of its five largest customers entered into new agreements, effective January 1, 2013, relating to the customer's gathering and processing volumes on the Texas portion of Enogex's system. The effects of this new arrangement are (i) a fixed fee processing agreement replaces the previous keep-whole agreement, (ii) the acreage dedicated by the customer to Enogex for gathering and processing in Texas has been increased for an extended term and (iii) the sale by Enogex of certain gas gathering assets in the Texas Panhandle portion of Enogex's system to this customer for cash proceeds of approximately $35 million. The sale of these assets was approved by the Company's and Enogex's Board of Directors in November 2012, therefore these assets were classified as held for sale on the Company's Consolidated Balance Sheet at December 31, 2012. Enogex expects to recognize a pre-tax gain of approximately $10 million in the first quarter of 2013 in its natural gas gathering and processing segment from the sale of these assets.

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, six 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, South Canadian or Wheeler gas processing plants. This 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, the 200 MMcf/d processing plant in Wheeler County, Texas which was placed into service in August 2012 and the 200 MMcf/d processing plant which is expected to be installed in Custer County, Oklahoma by the end of 2013.

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 2012 included Chesapeake Energy Marketing Inc., Apache Corporation and Devon Energy Production Company, L.P. In 2012, these customers accounted for 19.6 percent, 17.8 percent and 10.6 percent, respectively, of Enogex's gathering and processing volumes. In 2012, Enogex's top 10 natural gas producer customers accounted for 73.0 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 Access 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 natural gas 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 Greater Granite Wash area, which includes the Colony Wash play in western Oklahoma and the Cleveland, Marmaton, Tonkawa and Granite Wash plays in western Oklahoma and in the Texas Panhandle.

In December 2011, Enogex completed construction of a cryogenic processing plant in Canadian County, Oklahoma, which added 200 MMcf/d of natural gas processing capacity to Enogex's system, and is supported by the installation of inlet and residue compression and 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.

In August 2012, Enogex completed construction of its cryogenic processing plant in Wheeler County, Texas, which added 200 MMcf/d of rich gas processing capacity to Enogex's system, and is supported by the installation of 9,400 horsepower of field compression, as well as 6,000 horsepower of inlet compression to facilitate additional flexibility in the operation of Enogex's "super-header" gathering system. The remainder of the inlet compression facilities is expected to be in service during the second quarter of 2013.

In support of significant long-term acreage dedications from its customers in the area, Enogex has expanded its gathering infrastructure in western Oklahoma and the Texas Panhandle. These expansions included the installation of 39,700 horsepower of low pressure compression and 235 miles of gathering pipe across the area, which was completed during the third quarter of 2012.

In support of significant long-term acreage dedications from its customers in the area, Enogex is expanding its gathering infrastructure in southern Oklahoma. The initial phase of these expansions include the installation of approximately 20,000 horsepower of compression and approximately 100 miles of gathering pipeline, which are expected to be in service by the end of the first quarter of 2013. The remainder of the expansion includes the installation of approximately 50,000 horsepower of compression and approximately 300 miles of gathering pipeline, which are expected to be in service by the end of 2013.

Enogex is constructing a cryogenic processing plant in Custer County, Oklahoma, which is expected add 200 MMcf/d of natural gas processing capacity to Enogex's system, and is expected to be supported by the installation of 6,000 horsepower of inlet compression and four miles of transmission pipeline. This plant will be connected to the Enogex "super-header" gathering system and is expected to be in service by the end of 2013.

Divestitures

Texas Panhandle Gathering Divestiture

On January 2, 2013, Enogex and one of its five largest customers entered into new agreements, effective January 1, 2013, relating to the customer's gathering and processing volumes on the Texas portion of Enogex's system. The effects of this new arrangement are (i) a fixed fee processing agreement replaces the previous keep-whole agreement, (ii) the acreage dedicated by the customer to Enogex for gathering and processing in Texas has been increased for an extended term and (iii) the sale by Enogex of certain gas gathering assets in the Texas Panhandle portion of Enogex's system to this customer for cash proceeds of approximately $35 million. The sale of these assets was approved by the Company's and Enogex's Board of Directors in November 2012, therefore these assets were classified as held for sale on the Company's Consolidated Balance Sheet at December 31, 2012. Enogex expects to recognize a pre-tax gain of approximately $10 million in the first quarter of 2013 in its natural gas gathering and processing segment from the sale of these assets.

Harrah Gathering and Processing Divestiture

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 in its natural gas gathering and processing segment.

Gas Gathering Acquisitions

In addition to the organic growth projects described above, the Company believes that the acquisition transactions described below will provide Enogex with key new opportunities in the greater Granite Wash area.

Western Oklahoma Gathering Acquisition

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 well as cash generated from operations and bank borrowings. The transactions closed on November 1, 2011. In support of these acquisitions, Enogex constructed 20 miles of 16-inch gathering pipe and over 11,000 horsepower of low pressure compression in 2012.

Granite Wash Gathering Acquisition

On August 1, 2012, Enogex entered into agreements with Chesapeake Midstream Gas Services, L.L.C. and Mid-America Midstream Gas Services, L.L.C., wholly-owned subsidiaries of Access Midstream Partners, L.P. and Chesapeake Midstream Development, L.P., respectively, pursuant to which Enogex agreed to acquire approximately 235 miles of natural gas gathering pipelines, right-of-ways and certain other midstream assets that provide natural gas gathering services in the greater Granite Wash area. The transactions closed on August 31, 2012. The aggregate purchase price for these transactions was approximately $78.6 million including reimbursement for certain permitted capital expenditures incurred during the period beginning June 1, 2012 and ending August 31, 2012. Enogex utilized cash generated from operations and bank borrowings to fund the purchase. In addition, Enogex also incurred acquisition-related costs of $3.5 million for sales taxes on acquired assets, which are included in taxes other than income. Enogex expects the purchase price allocations to be completed by the end of the first quarter of 2013.

In connection with these agreements, Enogex entered into a gas gathering and processing agreement with Chesapeake effective September 1, 2012 pursuant to which Enogex began providing fee-based natural gas gathering, compression, processing and transportation services to Chesapeake with respect to certain acreage dedicated by Chesapeake.

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. 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. 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. In March 2012, Enogex reached a settlement agreement with its insurers in this matter. As a result of the settlement agreement, Enogex received additional reimbursements of $7.6 million and recognized a gain of $7.5 million on insurance proceeds in 2012.

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 2012, Enogex incurred $13.7 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 2013 to 2017 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 required PHMSA to direct pipeline operators to verify the maximum allowable operating pressure of their pipelines by July 3, 2

012, 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.

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.

It is estimated that OG&E's and Enogex's total expenditures to comply with environmental laws, regulations and requirements for 2013 will be $63.0 million and $6.4 million, respectively, of which $45.3 million and $0.7 million, respectively, are for capital expenditures. It is estimated that OG&E's and Enogex's total expenditures to comply for environmental laws, regulations and requirements for 2014 will be $37.7 million and $6.3 million, respectively, of which $19.2 million and $0.5 million, respectively, are for capital expenditures. The amounts for OG&E above include capital expenditures for low NOX burners and exclude certain other capital expenditures as discussed in the capital expenditures table and related footnote D in "Finance and Construction" below. The Company's management believes that all of its operations are in substantial compliance with current Federal, state and local environmental standards. 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 2013 through 2017 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)	2013	2014	2015	2016	2017
OG&E Base Transmission	$65	$50	$50	$50	$50
OG&E Base Distribution	175	175	175	175	175
OG&E Base Generation	80	75	75	75	75
OG&E Other	15	15	15	15	15
Total OG&E Base Transmission, Distribution, Generation and Other	335	315	315	315	315
OG&E Known and Committed Projects:					
Transmission Projects:					
Balanced Portfolio 3E Projects (A)	205	25	—	—	—
SPP Priority Projects (B)	165	110	—	—	—
SPP Integrated Transmission Projects (C)	5	5	—	40	40
Total Transmission Projects	375	140	—	40	40
Other Projects:					
Smart Grid Program	25	25	10	10	—
System Hardening	15	—	—	—	—
Environmental - low NOX burners	30	20	25	20	—
Total Other Projects	70	45	35	30	—
Total OG&E Known and Committed Projects	445	185	35	70	40
Total OG&E (D)	780	500	350	385	355
Enogex LLC Base Maintenance	50	55	55	55	55
Enogex LLC Known and Committed Projects:					
Western Oklahoma / Texas Panhandle Gathering Expansion	380	180	140	80	65
Other Gathering Expansion	25	15	10	10	10
Total Enogex LLC Known and Committed Projects	405	195	150	90	75
Total Enogex LLC (E)	455	250	205	145	130
OGE Energy	10	10	10	10	10
Total capital expenditures	$1,245	$760	$565	$540	$495

(A) Balanced Portfolio 3E includes three 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 $175 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 $115 million for OG&E, which is expected to be in service by mid-2014 and (iii) construction of 39 miles of transmission

21

line from OG&E's Sooner substation in an eastern direction to the Grand River Dam Authority Cleveland substation at an estimated cost of $45 million for OG&E, which was placed in service in February 2013.

(B) 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. OG&E began construction on the Hitchland project in November 2012 and expects to begin construction on the Kansas project in June 2013.

(C) On January 31, 2012, the SPP approved the Integrated Transmission Plan Near Term and Integrated Transmission Plan 10-year projects. These plans include two projects to be built by OG&E: (i) construction of 47 miles of transmission line from OG&E's Gracemont substation in a northwestern direction to a companion transmission line to be built by American Electric Power to its Elk City substation at an estimated cost of $75 million for OG&E, which is expected to be in service by early 2018, and (ii) construction of 126 miles of transmission line from OG&E's Woodward District Extra High Voltage substation in a southeastern direction to OG&E's Cimarron substation and construction of a new substation on this transmission line, the Mathewson substation, at an estimated cost of $210 million for OG&E, which is expected to be in service by early 2021. On April 9, 2012, OG&E received a notice to construct these projects from the SPP. On June 26, 2012, OG&E responded to the SPP that OG&E will construct the projects discussed above and is moving forward with more detailed cost estimates that must be reviewed and approved by the SPP. OG&E and American Electric Power are currently in discussions regarding how much of the 94 mile Elk City to Gracemont transmission line will be built by OG&E and American Electric Power. American Electric Power has argued for a larger portion of such transmission line than the traditional 50 percent split. The capital expenditures related to these projects are presented in the summary of capital expenditures for known and committed projects above.

(D) The capital expenditures above exclude any environmental expenditures associated with:

- Pollution control equipment related to controlling SO2 emissions under the regional haze requirements due to the uncertainty regarding the approach and timing for such pollution control equipment. The SO2 emissions standards in the EPA's FIP 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 FIP is being challenged by OG&E and the state of Oklahoma. On June 22, 2012, OG&E was granted a stay of the FIP by the U.S. Court of Appeals for the Tenth Circuit, which delays the timing of required implementation of the SO2 emissions standards in the rule. The merits of the appeal have been fully briefed, and oral argument is scheduled to occur on March 6, 2013. Neither the outcome of the challenge to the FIP nor the timing of any required capital expenditures can be predicted with any certainty at this time, but such capital expenditures could be significant.
- Installation of control equipment for compliance with MATS by a deadline of April 16, 2015, with the possibility of a one-year extension. OG&E is currently planning to utilize activated carbon injection and low levels of dry sorbent injection at each of its five coal-fired units. Due to various uncertainties about the final design, the potential use of this technology relating to regional haze measures and the specifications for the control equipment, the resulting cost estimates currently range from $34 million to $72 million per unit.

OG&E is currently evaluating options to comply with environmental requirements. For further information, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Environmental Laws and Regulations" below.

(E)

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 27, 2013 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 2012 and 2011, OGE Energy made contributions to its Pension Plan of $35 million and $50 million, respectively, to help ensure that the Pension Plan maintains an adequate funded status. During 2013, OGE Energy expects to 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 November 2012 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 $0.4175 per share from $0.3925 per share effective with the Company's first quarter 2013 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. The short-term debt balance was $430.9 million and $277.1 million at December 31, 2012 and 2011, respectively. The weighted-average interest rate on short-term debt at December 31, 2012 was 0.43 percent. The average balance of short-term debt in 2012 was $451.0 million at a weighted-average interest rate of 0.45 percent. The maximum month-end balance of short-term debt in 2012 was $608.2 million. At December 31, 2012, Enogex had no outstanding borrowings under its revolving credit agreement as compared to $150.0 million at December 31, 2011. 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, 2012, the Company had $1,116.9 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, 2013 and ending December 31, 2014. At December 31, 2012, the Company had $1.8 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 up to $250 million of long-term debt in the first half of 2013, 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 $12 million and $15 million of common stock in its Automatic Dividend Reinvestment and Stock Purchase Plan in 2013. 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 3,377 employees at December 31, 2012.

EXECUTIVE OFFICERS

The following persons were Executive Officers of the Registrant as of February 27, 2013:

Name	Age	Title
Peter B. Delaney	59	Chairman of the Board, President and Chief Executive Officer - OGE Energy Corp.
Sean Trauschke	46	Vice President and Chief Financial Officer - OGE Energy Corp.
E. Keith Mitchell	50	President and Chief Operating Officer - Enogex Holdings
Stephen E. Merrill	48	Chief Operating Officer of Enogex LLC
William J. Bullard	64	Assistant General Counsel - OGE Energy Corp.
Scott Forbes	55	Controller and Chief Accounting Officer - OGE Energy Corp.
Patricia D. Horn	54	Vice President - Governance, Environmental and Corporate Secretary - OGE Energy Corp.
Gary D. Huneryager	62	Vice President - Internal Audits - OGE Energy Corp.
Jesse B. Langston	50	Vice President - Retail Energy - OG&E
Jean C. Leger, Jr.	54	Vice President - Utility Operations - OG&E
Cristina F. McQuistion	48	Vice President - Strategic Planning, Performance Improvement and Chief Information Officer - OGE Energy Corp.
Max J. Myers	38	Treasurer - OGE Energy Corp.
Jerry A. Peace	50	Chief Risk Officer - OGE Energy Corp.
Paul L. Renfrow	56	Vice President - Public Affairs, Human Resources and Health & Safety - OGE Energy Corp.

No family relationship exists between any of the Executive Officers of the Registrant. Messrs. Delaney, Trauschke, Bullard, Forbes, Huneryager, Myers, 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 16, 2013.

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
	2008 - Present:	Chief Executive Officer of Enogex LLC
	2008 - 2010:	Chairman of the Board, President and Chief Executive Officer of OGE Energy Corp. and OG&E
	2008:	Chief Executive Officer of Enogex Inc.
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
	2009 - Present:	Chief Financial Officer of Enogex LLC
	2008 - 2009:	Senior Vice President - Investor Relations and Financial Planning of Duke Energy (electric utility)
E. Keith Mitchell	2011 - Present:	President and Chief Operating Officer of Enogex Holdings; President of Enogex LLC
	2008 - 2011:	Senior Vice President and Chief Operating Officer of Enogex LLC
	2008:	Senior Vice President and Chief Operating Officer 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
	2008:	Vice President and Chief Financial Officer of Enogex Inc.
William J. Bullard	2010 - Present:	Assistant General Counsel of OGE Energy Corp.; General Counsel of OG&E
	2008 - 2010:	Assistant General Counsel of OGE Energy Corp. and OG&E
Scott Forbes	2008 - 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	2012 - Present:	Vice President - Governance, Environmental and Corporate Secretary of OGE Energy Corp. and OG&E; Secretary of Enogex Holdings; Corporate Secretary of Enogex LLC
	2010 - 2012:	Vice President - Governance, Environmental, Health & Safety; Corporate Secretary of OGE Energy Corp. and OG&E; Secretary of Enogex Holdings; Corporate Secretary of Enogex LLC
	2008 - 2010:	Vice President - Legal, Regulatory, Environmental Health & Safety, General Counsel and Secretary of Enogex LLC
	2008 - 2010:	Assistant General Counsel of OGE Energy Corp.
	2008:	Vice President - Legal, Regulatory, Environmental Health & Safety, General Counsel and Secretary of Enogex Inc.
Gary D. Huneryager	2008 - Present:	Vice President - Internal Audits of OGE Energy Corp. and OG&E
Jesse B. Langston	2011 - Present:	Vice President - Retail Energy of OG&E
	2008 - 2011:	Vice President - Utility Commercial Operations of OG&E
Jean C. Leger, Jr.	2008 - Present:	Vice President - Utility Operations of OG&E
	2008:	Vice President of Operations of Enogex Inc.
Cristina F. McQuistion	2013 - Present:	Vice President - Strategic Planning, Performance Improvement and Chief Information Officer of OGE Energy Corp. and OG&E
	2011 - 2013:	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

2008:	Executive Vice President and General Manager Point of Sale Systems of Teleflora (floral industry and software services to floral industry company)

Name	Business Experience	
Max J. Myers	2009 - Present:	Treasurer of OGE Energy Corp. and OG&E
	2010 - Present:	Treasurer of Enogex Holdings
	2008 - 2009:	Managing Director of Corporate Development and Finance of OGE Energy Corp. and OG&E
	2008:	Manager of Corporate Development of OGE Energy Corp. and OG&E
Jerry A. Peace	2008 - Present:	Chief Risk Officer of OGE Energy Corp. and OG&E
	2008:	Chief Risk Officer and Compliance Officer of OGE Energy Corp. and OG&E
Paul L. Renfrow	2012 - Present	Vice President - Public Affairs, Human Resources and Health & Safety of OGE Energy Corp. and OG&E
	2011 - 2012:	Vice President - Public Affairs and Human Resources of OGE Energy Corp. and OG&E
	2008 - 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 Securities Exchange Act of 1934 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 "we," "our" and "us" refer to the Company. 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

OG&E's profitability depends to a large extent on the ability 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.

OG&E is subject to comprehensive regulation by several Federal and state utility regulatory agencies, which significantly influences its operating environment and its ability to fully recover its costs from utility customers. Recoverability of any under recovered amounts from OG&E's customers due to a rise in fuel costs is a significant risk. The utility commissions in the states where OG&E operates regulate many aspects of its utility operations including siting and construction of facilities, customer service and the rates that OG&E can charge customers. The profitability of the utility operations is dependent on OG&E's ability to fully recover costs related to providing energy and utility services to its customers.

In recent years, the regulatory environments in which OG&E operates have received an increased amount of attention. It is possible that there could be changes in the regulatory environment that would impair OG&E's ability to fully recover costs historically paid by OG&E's customers. State utility commissions generally possess broad powers to ensure that the needs of the utility customers are being met. OG&E cannot assure that the OCC, APSC and the FERC will grant rate increases in the future or in the amounts requested, and they could instead lower OG&E's rates.

OG&E is unable to predict the impact on its operating results from the future regulatory activities of any of the agencies that regulate OG&E. Changes in regulations or the imposition of additional regulations could have an adverse impact on OG&E's 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, including a change in our return on equity, 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. As discussed in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Environmental Laws and Regulations", in 2011, the EPA accepted a portion of the Oklahoma SIP for regional haze, which requires the installation of low NOX burners on OG&E's affected units within five years at a cost of approximately $95 million. The EPA rejected Oklahoma's SO2 BART determination with respect to the four affected coal-fired units at the Sooner and Muskogee generating stations and issued a FIP in its place. The SO2 emissions standards in the EPA's FIP 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. OG&E, the state of Oklahoma and other parties, filed an appeal to challenge this determination, which has delayed the implementation of the regional haze rule in Oklahoma. Neither the outcome of the appeal nor the timing of any required expenditures for pollution control equipment can be predicted with any certainty at this time.

In response to recent regulatory and judicial decisions, 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. These activities 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 or requiring remedial action to mitigate pollution conditions that may be caused by their operations or that are attributable to former operators. OG&E and Enogex 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 may not be able to recover the costs of our substantial planned investment in capital improvements and additions.

OG&E's business plan 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 OG&E charges, it would not be able to recover the costs associated with its planned extensive investment. This could adversely affect OG&E's financial position and results of operations. While OG&E may seek to limit the impact of any denied recovery by attempting to reduce the scope of its 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 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 consolidated financial position, results of operations 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.

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, including the forthcoming SPP integrated marketplace, which is scheduled to begin operation in March 2014.

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

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

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

Enogex's natural gas gathering and intrastate transportation operations are generally exempt from the jurisdiction of the FERC under the Natural Gas Act of 1938, but the FERC regulation may indirectly impact these businesses and the markets for products derived from these businesses. The FERC's policies and practices across the range of its oil and natural gas regulatory activities, including, for example, its policies on interstate open access transportation, ratemaking and capacity release and its promotion of market centers, may indirectly affect intrastate markets. In recent years, the FERC has aggressively pursued pro-competitive policies in its regulation of interstate oil and natural gas pipelines. However, we cannot assure 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 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). See Note 17 of Notes to Consolidated Financial Statements for a discussion of Enogex's FERC Section 311 rate case. 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 2012, Enogex incurred $13.7 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 2013 to 2017 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 required 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, results of operations, 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 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. OG&E'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 $1.0 million per day per violation for noncompliance. In order to comply with new or updated security regulations, we may be required to make changes to our current operations which could also result in additional expenses. 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 and natural gas for much of our electric generating capacity. We rely on suppliers to deliver coal and natural gas in accordance with short and long-term contracts. We have certain supply contracts in place; however, there can be no assurance that the counterparties to these agreements will fulfill their obligations to supply coal and natural gas 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 and natural gas to us under certain circumstances, such as in the event of a natural disaster. Deliveries 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 and natural gas 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, results of operations and cash flows.

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 financial risks associated with climate change.

Climate change creates financial risk. Potential regulation associated with climate change legislation could pose financial risks to the Company. In addition, 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 are subject to cyber security risks and increased reliance on processes automated by technology.

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 our consolidated financial position, results of operations and cash flows.

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 (including smart grid) and Enogex's transportation systems which may result in a loss of service to customers and also subject OG&E and Enogex to financial harm due to the significant expense to repair security breaches or system damage. 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 its consolidated financial position, results of operations and cash flows.

Our security procedures, which include among others, virus protection software, cyber security and our business continuity planning, including disaster recovery policies and back-up systems, may not be adequate or implemented properly to fully address the adverse affect of cyber security attacks on our systems, which could adversely impact our operations.

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

The long-term impact of terrorist attacks 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, and prolonged droughts, 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. In addition, prolonged droughts could cause a lack of sufficient water for use in cooling during the electricity generating process.

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 21 percent of its gross margin and accounted for 21 percent of its natural gas processed volumes in 2012, 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 two percent and five percent, respectively, of its gross margin and accounted for 16 percent and 28 percent, respectively, of its natural gas processed volumes in 2012. 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 gross margin 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 consolidated financial position, 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, transportation and storage facilities would decline, which could have a material adverse effect on its consolidated financial position, 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 are currently around $3.21 per MMBtu. A 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 and composition 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 may engage in commodity hedging activities to minimize the impact of commodity price risk, which may have a volatile effect on its results of operations and cash flows.

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

From time to time, Enogex has instituted a hedging program that was intended to reduce the commodity price risk associated with 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 operations and natural gas transportation and storage operations (operational gas hedges). 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. Enogex's key natural gas producer customers in 2012 included Chesapeake Energy Marketing Inc., Apache Corporation and Devon Energy Production Company, L.P. In 2012, these customers accounted for 19.6 percent, 17.8 percent and 10.6 percent, respectively, of Enogex's gathering and processing volumes. In 2012, Enogex's top 10 natural gas producer customers accounted for 73.0 percent of Enogex's gathering and processing volumes. 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 2012, 2011 and 2010, revenues from Enogex's firm intrastate natural gas transportation and storage contracts were $131.5 million, $130.7 million and $116.6 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 stated term of the PSO contract expired January 1, 2013, 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 January 1, 2013, the PSO contract will remain in effect at least through January 1, 2014. 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, 2013, the OG&E contract will remain in effect at least through April 30, 2014. 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. Additionally, Enogex depends on third parties to provide electricity for compression at many of its facilities. 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 consolidated financial position and results of operations.

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 was initially entitled 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. At December 31, 2012, OGE Energy indirectly owns a 79.9 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.

FINANCIAL RISKS

Market performance, increased retirements, changes in retirement plan regulations and increasing costs associated with our Pension Plan, health care plans and other employee-related benefits may adversely affect our consolidated financial position, results of operations or liquidity.

We have a Pension Plan that covers a significant amount of our employees hired before December 1, 2009. We also have defined benefit postretirement plans that cover a significant amount 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 results of operations and funding requirements. Based on our assumptions at December 31, 2012, we expect to continue to make future contributions to maintain required funding levels. It has been our practice in the past to also make voluntary contributions to maintain more prudent funding levels than minimally required. We may continue to make voluntary contributions in the future. These amounts are estimates and may change based on actual stock market performance, changes in interest rates and any changes in governmental regulations.

If the employees who participate in the Pension Plan 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 consolidated financial position and results of operations. Those factors are outside of our control.

In addition to the costs of our Pension Plan, 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, will continue to rise. The increasing costs and funding requirements with our Pension Plan, health care plans and other employee benefits may adversely affect our consolidated financial position, results of operations 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, 2012, the Company and its subsidiaries had outstanding indebtedness and other liabilities of $6.8 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 could 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 could also lead to higher long-term borrowing costs and, if below investment grade, would 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 and pipeline operations. Credit risk includes the risk that counterparties that owe us money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements. In that event, our financial results could be adversely affected and we could incur losses.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

OG&E

OG&E owns and operates an interconnected electric generation, transmission and distribution system, located in Oklahoma and western Arkansas, which included 10 generating stations with an aggregate capability of 6,807 MWs at December 31, 2012. 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	2012 Capacity Factor (A)		Unit Capability (MW)	Station Capability (MW)
Seminole	1	1971	Steam-Turbine	Gas	Base Load	24.8	%	465	
	1GT	1971	Combustion-Turbine	Gas	Peaking	0.2	% (B)	16	
	2	1973	Steam-Turbine	Gas	Base Load	18.9	%	490	
	3	1975	Steam-Turbine	Gas/Oil	Base Load	26.3	%	477	1,448
Muskogee	4	1977	Steam-Turbine	Coal	Base Load	57.8	%	489	
	5	1978	Steam-Turbine	Coal	Base Load	62.5	%	509	
	6	1984	Steam-Turbine	Coal	Base Load	52.7	%	508	1,506
Sooner	1	1979	Steam-Turbine	Coal	Base Load	61.2	%	516	
	2	1980	Steam-Turbine	Coal	Base Load	62.7	%	520	1,036
Horseshoe Lake	6	1958	Steam-Turbine	Gas/Oil	Base Load	17.7	%	171	
	7	1963	Combined Cycle	Gas/Oil	Base Load	15.5	%	222	
	8	1969	Steam-Turbine	Gas	Base Load	12.3	%	399	
	9	2000	Combustion-Turbine	Gas	Peaking	3.7	% (B)	45	
	10	2000	Combustion-Turbine	Gas	Peaking	3.4	% (B)	45	882
Redbud (C)	1	2003	Combined Cycle	Gas	Base Load	62.7	%	148	
	2	2003	Combined Cycle	Gas	Base Load	65.4	%	149	
	3	2003	Combined Cycle	Gas	Base Load	70.7	%	146	
	4	2003	Combined Cycle	Gas	Base Load	47.1	%	151	594
Mustang	1	1950	Steam-Turbine	Gas	Peaking	3.2	% (B)	52	
	2	1951	Steam-Turbine	Gas	Peaking	4.6	% (B)	52	
	3	1955	Steam-Turbine	Gas	Base Load	16.3	%	117	
	4	1959	Steam-Turbine	Gas	Base Load	13.8	%	250	
	5A	1971	Combustion-Turbine	Gas/Jet Fuel	Peaking	0.7	% (B)	34	
	5B	1971	Combustion-Turbine	Gas/Jet Fuel	Peaking	0.8	% (B)	33	538
McClain (D)	1	2001	Combined Cycle	Gas	Base Load	85.8	%	354	354
Total Generating Capability (all stations, excluding wind stations) (E)									6,358

Station	Year Installed	Location	Number of Units	Fuel Capability	2012 Capacity Factor (A)		Unit Capability (MW)	Station Capability (MW)
Crossroads	2011	Woodward, OK	99	Wind	45.8	%	2.3	227.5
Centennial	2007	Woodward, OK	80	Wind	33.2	%	1.5	120
OU Spirit	2009	Woodward, OK	44	Wind	36.9	%	2.3	101
Total Generating Capability (wind stations)								448.5

(A) 2012 Capacity Factor = 2012 Net Actual Generation / (2012 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) In December 2012, the Enid and Woodward generating stations were retired.

At December 31, 2012, OG&E's transmission system included: (i) 51 substations with a total capacity of 11.9 million kilovolt-amps and 4,426 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 9.4 million kilovolt-amps, 29,103 structure miles of overhead lines, 2,110 miles of underground conduit and 10,580 miles of underground conductors in Oklahoma and (ii) 38 substations with a total capacity of 1.1 million kilovolt-amps, 2,778 structure miles of overhead lines, 219 miles of underground conduit and 700 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, service centers, 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, 2012, Enogex and its subsidiaries owned: (i) approximately 6,640 miles of intrastate natural gas gathering pipelines in Oklahoma and Texas; (ii) approximately 2,284 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) 660,655 horsepower of owned compression and (v) nine operating natural gas processing plants, with a current total inlet capacity of 1,305 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	2012 Average Daily Inlet Volumes (MMcf/d)	Inlet Capacity (MMcf/d)
Calumet (A) (B)	1969	Lean Oil	Gas/Electric	68	250
South Canadian (A)	2011	Cryogenic	Electric	192	200
Wheeler (A) (C)	2012	Cryogenic	Electric	155	200
Cox City (A)	1994	Cryogenic	Gas/Electric	146	180
Thomas (A)	1981	Cryogenic	Gas	117	135
Clinton (A)	2009	Cryogenic	Electric	84	120
Roger Mills (D)	2008	Refrigeration	Electric	31	100
Canute (D)	1996	Cryogenic	Electric	54	60
Wetumka (A)	1983	Cryogenic	Gas/Electric	32	60
Total				879	1,305

(A) These processing plants are located on property that Enogex owns in fee.
(B) This processing plant will be used when additional capacity is required.
(C) This processing plant was placed into service in August 2012.
(D) These processing plants are located on easements or leased property as described above.

Enogex currently occupies 134,219 square feet of office space at its executive offices at 211 N. Robinson, Suite 900, Oklahoma City, Oklahoma 73102 under a lease that expires March 31, 2017. 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, 2012, the Company's gross property, plant and equipment (excluding construction work in progress) additions were $3.3 billion and gross retirements were $415.7 million (including assets held for sale of $31.1 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 29.0 percent of gross property, plant and equipment (excluding construction work in progress) at December 31, 2012.

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 or claims made by third parties, including governmental 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. At the present time, based on currently available information, except as set forth below, under "Environmental Laws and Regulations" in Item 7 of Part II of this Form 10-K and in Notes 16 and 17 of Notes to Consolidated Financial Statements, the Company believes that any reasonably possible losses in excess of accrued amounts arising out of pending or threatened lawsuits or claims would not be quantitatively material to its financial statements and would not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

1. 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, results of operations or cash flows.

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.

	Dividend	Price	
2013	Paid	High	Low
First Quarter (through February 22)	$0.4175	$60.00	$56.12
2012			
First Quarter	$0.3925	$57.54	$51.24
Second Quarter	0.3925	55.31	50.23
Third Quarter	0.3925	56.49	50.60
Fourth Quarter	0.3925	60.21	54.36
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

At the Company's November 2012 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 $0.4175 per share from $0.3925 per share effective with the Company's first quarter 2013 dividend.

The number of record holders of the Company's Common Stock at December 31, 2012, was 18,905. The book value of the Company's Common Stock at December 31, 2012 was $28.02.

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, any 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.

Issuer Purchases of Equity Securities

The following table contains information about the Company's purchases of its common stock during the fourth quarter of 2012.

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
10/1/12 – 10/31/12	—		$—	N/A	N/A
11/1/12 – 11/30/12	60,000	(A)	$55.41	60,000	N/A
12/1/12 – 12/31/12	357	(B)	$57.04	N/A	N/A

(A) In November 2012, the Company purchased 60,000 shares of its common stock at an average cost of $55.41 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 2013.

(B) These shares of restricted stock were returned to the Company to satisfy tax liabilities.

N/A – not applicable

Item 6. Selected Financial Data

HISTORICAL DATA					
Year ended December 31	2012	2011	2010	2009	2008
SELECTED FINANCIAL DATA					
(In millions, except per share data)					
Results of Operations Data:					
Operating revenues	$3,671.2	$3,915.9	$3,716.9	$2,869.7	$4,070.7
Cost of goods sold	1,918.7	2,277.9	2,187.4	1,557.7	2,818.0
Gross margin on revenues	1,752.5	1,638.0	1,529.5	1,312.0	1,252.7
Operating expenses	1,075.6	991.3	935.6	820.1	790.6
Operating income	676.9	646.7	593.9	491.9	462.1
Interest income	0.6	0.5	—	1.4	6.7
Allowance for equity funds used during construction	6.2	20.4	11.4	15.1	—
Other income	17.0	19.3	13.7	27.5	15.4
Other expense	16.5	21.7	17.9	16.3	25.6
Interest expense	164.1	140.9	139.7	137.4	120.0
Income tax expense	135.1	160.7	161.0	121.1	101.2
Net income	385.0	363.6	300.4	261.1	237.4
Less: Net income attributable to noncontrolling interests	30.0	20.7	5.1	2.8	6.0
Net income attributable to OGE Energy	$355.0	$342.9	$295.3	$258.3	$231.4
Basic earnings per average common share attributable to OGE Energy common shareholders	$3.60	$3.50	$3.03	$2.68	$2.50
Diluted earnings per average common share attributable to OGE Energy common shareholders	$3.58	$3.45	$2.99	$2.66	$2.49
Dividends declared per common share	$1.5950	$1.5175	$1.4625	$1.4275	$1.3975
Balance Sheet Data (at period end):					
Property, plant and equipment, net	$8,344.8	$7,474.0	$6,464.4	$5,911.6	$5,249.8
Total assets	$9,922.2	$8,906.0	$7,669.1	$7,266.7	$6,518.5
Long-term debt	$2,848.6	$2,737.1	$2,362.9	$2,088.9	$2,161.8
Total stockholders' equity	$3,072.4	$2,819.3	$2,400.0	$2,060.8	$1,914.0
Capitalization Ratios (A)					
Stockholders' equity	51.9 %	50.7 %	50.4 %	46.4 %	47.0 %
Long-term debt	48.1 %	49.3 %	49.6 %	53.6 %	53.0 %
Ratio of Earnings to Fixed Charges (B)					
Ratio of earnings to fixed charges	3.94	4.12	4.02	3.38	3.55

(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 three business segments: (i) electric utility, (ii) natural gas transportation and storage and (iii) natural gas gathering and processing.

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 and storing 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. During the third quarter of 2012, the operations and activities of EER were fully integrated with those of Enogex through the creation of a new commodity management organization. This new organization is intended to facilitate the execution of Enogex's strategy through an enhanced focus on asset optimization and active management of its growing natural gas, NGLs and condensate positions. The operations of EER, including asset management activities, have been included in the natural gas transportation and storage segment and have been restated for all prior periods presented. Enogex's operations are now organized into two business segments: (i) natural gas transportation and storage and (ii) natural gas gathering and processing. At December 31, 2012, OGE Energy indirectly owns a 79.9 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 focusing on safety, efficiency, reliability, customer service and risk management. 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.

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 expects to maintain a diverse generation portfolio while remaining environmentally responsible. 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 as well as allow customers to monitor and manage their energy usage, which should help reduce demand during critical peak times, resulting in lower capacity requirements. 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. The Smart Grid program also provides benefits to OG&E, including more efficient use of its resources and access to increased information about customer usage, which should enable OG&E to have better distribution system planning data, better response to customer usage questions and faster detection and restoration of system outages. 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.

Enogex's business plan entails growing its businesses and providing attractive financial returns through efficient operations and effective commercial management of its assets. Enogex also plans to capture growth opportunities through expansion projects, increased utilization of existing assets and through acquisitions (including joint ventures) in and around its footprint and attracting new customers. 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.

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.

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

2012 compared to 2011. Net income attributable to OGE Energy was $355.0 million, or $3.58 per diluted share, in 2012 as compared to $342.9 million, or $3.45 per diluted share, in 2011. The increase in net income attributable to OGE Energy of $12.1 million, or 3.5 percent, or $0.13 per diluted share, in 2012 as compared to 2011 was primarily due to:

- an increase in net income at OG&E of $17.0 million, or 6.5 percent, or $0.18 per diluted share of the Company's common stock, primarily due to a higher gross margin and lower income tax expense. The higher gross margin was primarily due to increased recovery of investments and increased transmission revenue partially offset by milder weather in OG&E's service territory. These increases were partially offset by higher other operation and maintenance expense, higher depreciation and amortization expense, lower allowance for equity funds used during construction and higher interest expense;
- a decrease in net income at Enogex of $8.1 million, or 9.9 percent, or $0.08 per diluted share of the Company's common stock, primarily due to higher other operation and maintenance expense, higher depreciation and amortization expense, lower other income 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 2011, higher interest expense and OGE Energy's lower membership interest in Enogex Holdings. These decreases were partially offset by a higher gross margin related to (i) increased gathering rates and volumes associated with ongoing expansion projects and increased volumes from gas gathering assets acquired in November 2011 and August 2012 and (ii) increased inlet volumes partially offset by lower average natural gas and NGLs prices. Also having a positive impact on net income was a higher gain on insurance proceeds in 2012 and an impairment related to the Atoka processing plant in 2011; and
- an increase in net income at OGE Energy of $3.2 million, or $0.03 per diluted share of the Company's common stock, primarily due to higher other income due to a decrease in deferred compensation losses partially offset by higher interest expense and a lower income tax benefit in 2012.

Non-Recurring Items. During 2012, Enogex had an increase in net income of $4.6 million due to a gain on insurance proceeds related to the reimbursement of costs incurred to replace the damaged train at the Cox City natural gas processing plant partially offset by a decrease in net income of $2.1 million related to sales taxes on the assets acquired in the gas gathering acquisitions in August 2012, as discussed in Note 3 of Notes to Consolidated Financial Statements, which Enogex does not consider to be reflective of its ongoing performance. During 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.

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 OGE Energy's lower membership interest in Enogex Holdings partially offset by a higher gross margin primarily from higher NGLs

prices and increased gathered volumes associated with ongoing expansion projects, 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 the 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.

Non-Recurring Item. During 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 Enogex's natural gas storage inventory at the lower of cost or market value. The offsetting gains from the sale of withdrawals from inventory were realized during the first quarter of 2012.

Recent Developments and Regulatory Matters

OG&E SPP Transmission Projects

In 2007, the SPP notified OG&E to construct 44 miles of a new 345 kilovolt transmission line originating at OG&E's existing Sooner 345 kilovolt substation and proceeding 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 connects to the companion line constructed in Kansas by Westar Energy. The transmission line was placed in service in April 2012. The total capital expenditures associated with this project were $45 million.

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 extends 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 transmission line was completed in April 2012. The total capital expenditures associated with this project were $157 million.

As discussed in Note 17 of Notes to Consolidated Financial Statements, the OCC approved a settlement agreement in OG&E's 2011 Oklahoma rate case filing that included an expedited procedure for recovering the costs of the two projects. On July 31, 2012, OG&E filed an application with the OCC requesting an order authorizing recovery for the two projects through the SPP transmission systems additions rider. On October 2, 2012, all parties signed a settlement agreement in this matter which stated: (i) the parties agree not to oppose requested relief sought by OG&E, (ii) OG&E will host meetings to discuss the SPP’s transmission planning process, including any future transmission projects for which OG&E has received a notice to construct from the SPP, and (iii) there will be opportunities for parties to provide input related to transmission planning studies that the SPP performs to identify future transmission projects. On October 25, 2012, the OCC issued an order approving the settlement agreement and granting OG&E cost recovery for the two projects. OG&E initiated cost recovery beginning with the first billing cycle in November 2012.

OG&E Demand and Energy Efficiency Program Filing

On July 2, 2012, OG&E filed an application with the OCC requesting approval of OG&E's 2013 demand portfolio, the authorization to recover the program costs, lost revenues associated with any achieved energy, demand savings and performance based incentives through the demand program rider and the recovery of costs associated with research and development investments. On July 16, 2012, OG&E filed an amended application which modified various calculations to reflect the rate of return authorized by the OCC in OG&E's 2011 rate case order and provided for consideration of a peak time rebate program. On December 20, 2012, the OCC approved a settlement with all parties in this matter. Key terms of the settlement included (i) approval of the program budgets proposed by OG&E and an additional amount of approximately $7 million over the three-year period for the energy efficiency programs, (ii) approval of OG&E's proposed Demand Program Rider tariff, (iii) the recovery through the Demand Program Rider of the increased program costs and the net lost revenues, incentives and research and development investments requested by OG&E, with the exception of lost revenues resulting from the Integrated Volt Var Control program (automated intelligence to control voltage and power on the distribution lines) and incentives for the SmartHours® and Integrated Volt Var Control demand response programs, (iv) recovery of the program costs on a levelized basis over the three-year period, (v) consideration of implementing a peak time rebate program in 2015 and (vi) the periodic filing of additional reports. The Demand Program Rider became effective on January 1, 2013.

OG&E Fuel Adjustment Clause Review for Calendar Year 2010

The OCC routinely reviews the costs recovered from customers through OG&E’s fuel adjustment clause. On August 19, 2011, the OCC Staff filed an application to review OG&E’s fuel adjustment clause for calendar year 2010, including the prudence of OG&E’s electric generation, purchased power and fuel procurement costs. OG&E responded by filing direct testimony and the minimum filing review package on October 18, 2011. On September 26, 2012, the administrative law judge recommended that the OCC find that for the calendar year 2010 OG&E's generation, purchase power and fuel procurement processes and costs, including the cost of replacement power for the Sooner 2 outage, were prudent and no disallowance (as discussed below) for any of these expenses is warranted. On January 31, 2013, the OCC issued an order approving the administrative law judge's recommendation. Previously, the Oklahoma Industrial Energy Consumers recommended that the OCC disallow recovery of approximately $44 million of costs previously recovered through OG&E's fuel adjustment clause. These recommendations were based on allegations that OG&E's lower cost coal-fired generation was underutilized, that OG&E failed to aggressively pursue purchasing power at a cost lower than its marginal cost of generation and that OG&E should be found imprudent related to an unplanned outage at OG&E's Sooner 2 coal unit in November and December 2010. Previously, the OCC Staff recommended approval of OG&E's actions related to utilization of coal plants and practices related to purchasing power but recommended that OG&E refund $3 million to customers because of the Sooner 2 outage.

Texas Panhandle Gathering Divestiture

On January 2, 2013, Enogex and one of its five largest customers entered into new agreements, effective January 1, 2013, relating to the customer's gathering and processing volumes on the Texas portion of Enogex's system. The effects of this new arrangement are (i) a fixed fee processing agreement replaces the previous keep-whole agreement, (ii) the acreage dedicated by the customer to Enogex for gathering and processing in Texas has been increased for an extended term and (iii) the sale by Enogex of certain gas gathering assets in the Texas Panhandle portion of Enogex's system to this customer for cash proceeds of approximately $35 million. The sale of these assets was approved by the Company's and Enogex's Board of Directors in November 2012, therefore these assets were classified as held for sale on the Company's Consolidated Balance Sheet at December 31, 2012. Enogex expects to recognize a pre-tax gain of approximately $10 million in the first quarter of 2013 in its natural gas gathering and processing segment from the sale of these assets.

Enogex Western Oklahoma / Texas Panhandle Natural Gas Gathering and Processing System Expansions

In August 2012, Enogex completed construction of its cryogenic processing plant in Wheeler County, Texas, which added 200 MMcf/d of rich gas processing capacity to Enogex's system, and is supported by the installation of 9,400 horsepower of field compression, as well as 6,000 horsepower of inlet compression to facilitate additional flexibility in the operation of Enogex's "super-header" gathering system. The remainder of the inlet compression facilities is expected to be in service during the second quarter of 2013.

In support of significant long-term acreage dedications from its customers in the area, Enogex has expanded its gathering infrastructure in western Oklahoma and the Texas Panhandle. These expansions included the installation of 39,700 horsepower of low pressure compression and 235 miles of gathering pipe across the area, which was completed during the third quarter of 2012.

In support of significant long-term acreage dedications from its customers in the area, Enogex is expanding its gathering infrastructure in southern Oklahoma. The initial phase of these expansions include the installation of approximately 20,000 horsepower of compression and approximately 100 miles of gathering pipeline, which are expected to be in service by the end of the first quarter of 2013. The remainder of the expansion includes the installation of approximately 50,000 horsepower of compression and approximately 300 miles of gathering pipeline, which are expected to be in service by the end of 2013.

Enogex is constructing a cryogenic processing plant in Custer County, Oklahoma, which is expected add 200 MMcf/d of natural gas processing capacity to Enogex's system, and is expected to be supported by the installation of 6,000 horsepower of inlet compression and four miles of transmission pipeline. This plant will be connected to the Enogex "super-header" gathering system and is expected to be in service by the end of 2013.

The capital expenditures related to the above 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."

Gas Gathering Acquisitions

On August 1, 2012, Enogex entered into agreements with Chesapeake Midstream Gas Services, L.L.C. and Mid-America Midstream Gas Services, L.L.C., wholly-owned subsidiaries of Access Midstream Partners, L.P. and Chesapeake Midstream Development, L.P., respectively, pursuant to which Enogex agreed to acquire approximately 235 miles of natural gas gathering pipelines, right-of-ways and certain other midstream assets that provide natural gas gathering services in the greater Granite Wash area. The transactions closed on August 31, 2012. The aggregate purchase price for these transactions was approximately $78.6 million including reimbursement for certain permitted capital expenditures incurred during the period beginning June 1, 2012 and ending August 31, 2012. Enogex utilized cash generated from operations and bank borrowings to fund the purchase. In addition, Enogex also incurred acquisition-related costs of $3.5 million for sales taxes on acquired assets, which are included in taxes other than income. Enogex expects the purchase price allocations to be completed by the end of the first quarter of 2013. The Company believes that the acquisition transactions will provide Enogex with key new opportunities in the greater Granite Wash area.

In connection with these agreements, Enogex entered into a gas gathering and processing agreement with Chesapeake effective September 1, 2012 pursuant to which Enogex began providing fee-based natural gas gathering, compression, processing and transportation services to Chesapeake with respect to certain acreage dedicated by Chesapeake.

The capital expenditures related to the above agreements 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."

2013 Outlook

The Company's 2013 earnings guidance is between approximately $335 million and $360 million of net income, or $3.35 to $3.60 per average diluted share.

Key assumptions for 2013 include:

Consolidated OGE

- Approximately 100 million average diluted shares outstanding;
- An effective tax rate of approximately 30 percent; and
- A projected loss at the holding company between approximately $2 million and $4 million, or $0.02 to $0.04 per diluted share, primarily due to interest expense relating to long and short-term debt borrowings partially offset by tax deductions.

OG&E

The Company projects OG&E to earn approximately $280 million to $290 million or $2.80 to $2.90 per average diluted share in 2013 and is based on the following assumptions:

- Normal weather patterns are experienced for the remainder of the year;
- Gross margin on revenues of approximately $1.290 billion to $1.295 billion based on sales growth of approximately 1.5 percent on a weather-adjusted basis;
- Approximately $75 million of gross margin is primarily attributed to regionally allocated transmission projects;
- Operating expenses of approximately $770 million to $780 million, with operation and maintenance expenses comprising 57 percent of the total;
-

Interest expense of approximately $130 million to $135 million which assumes a $3 million allowance for borrowed funds used during construction reduction to interest expense and $250 million of long-term debt issued in the first half of 2013;

- Allowance for equity funds used during construction of approximately $10 million; and
- An effective tax rate of approximately 28 percent.

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

Enogex

The Company projects Enogex to earn approximately $55 million to $75 million, or $0.55 to $0.75 per average diluted share and EBITDA between $213 million and $241 million, in 2013 net of noncontrolling interest, and is based on the following assumptions:

- Total Enogex anticipated gross margin of between approximately $470 million and $500 million. The gross margin assumption includes:
- Natural gas transportation and storage gross margin contribution of between approximately $130 million and $140 million, of which 83 percent is attributable to the transportation business;
- Natural gas gathering and processing gross margin contribution of between approximately $340 million and $360 million, of which 51 percent is attributable to the processing business;
- Key factors affecting the natural gas gathering and processing gross margin forecast are:
- Assumed increase of approximately 10 to 15 percent in gathered volumes over 2012;
- Assumed increase of approximately 10 to 15 percent in processable* volumes over 2012;
- At the midpoint of Enogex's natural gas gathering and processing assumption Enogex has assumed:
- An average processing contract mix of 48 percent fixed-fee, 23 percent percent-of-liquids, 19 percent percent-of-proceeds and 10 percent keep-whole;
- Average natural gas price of $3.38 per MMBtu in 2013;
- Average NGLs price of $0.82 per gallon in 2013;
- Average price per gallon of condensate of $2.13 in 2013;
- Ethane is projected to be in rejection for 2013;
- Approximately 50 percent of NGLs volumes are expected to flow to Mt. Belvieu; and
- A 10 percent change in the average NGLs price for the entire year impacts net income approximately $5 million;
- Enogex has assumed operating expenses of approximately $325 million to $335 million, with operation and maintenance expenses comprising 54 percent of the total;
- A pre-tax gain of approximately $10 million associated with asset sales in the first quarter of 2013;
- Interest expense of approximately $30 million to $35 million;
- An effective tax rate of approximately 38 percent; and
- ArcLight group will own approximately 22 percent of Enogex Holdings by the end of 2013.

2014 Volume projections for Enogex:

- Assumed increase of approximately five to 10 percent in gathered volumes over 2013; and
- Assumed increase of approximately 10 to 20 percent in processable* volumes over 2013.

* Processable volumes are the natural gas production that are on Enogex's gathering systems that are available to be processed, some of which is moved off of the system and is not processed under one of Enogex's processing agreements. Processable volumes include condensate volumes which are captured in the gathering pipeline and therefore not included in plant inlet volumes.

EBITDA is a supplemental non-GAAP financial measure used by external users of the Company's financial statements such as investors, commercial banks and others; therefore, the Company has included the table below which provides a reconciliation of projected EBITDA to projected net income attributable to Enogex Holdings at the midpoint of Enogex Holdings' earnings assumptions for 2013, which does not include the effect of income taxes whereas OGE Energy's portion of Enogex Holdings' net income included in OGE Energy's earnings guidance does reflect the effect of income taxes. Enogex Holding's net income shown in the EBITDA table does not include the effect of income taxes because Enogex Holdings is a partnership and is not subject to income taxes. Each partner is responsible for paying their own income taxes. For a discussion of the reasons for the use of EBITDA, as well as its limitations as an analytical tool, see "Non-GAAP Financial Measure" below.

48

Reconciliation of projected EBITDA to projected net income attributable to Enogex Holdings

(In millions)	Twelve Months Ended December 31, 2013 (A)(B)
Net income attributable to Enogex Holdings	$132
Add:	
Interest expense, net	33
Depreciation and amortization expense (C)	123
EBITDA	$288
OGE Energy's portion	$228

(A) Based on the midpoint of Enogex Holdings' earnings guidance for 2013.

(B) As of November 1, 2010, Enogex Holdings' earnings are no longer subject to tax (other than Texas state margin taxes) and are taxable at the individual partner level.

(C) Includes amortization of certain customer-based intangible assets associated with the acquisition from Cordillera in November 2011, which is included in gross margin for financial reporting purposes.

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, 2012, 2011 and 2010 and the Company's consolidated financial position at December 31, 2012 and 2011. 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)	2012	2011	2010
Operating income	$676.9	$646.7	$593.9
Net income attributable to OGE Energy	$355.0	$342.9	$295.3
Basic average common shares outstanding	98.6	97.9	97.3
Diluted average common shares outstanding	99.1	99.2	98.9
Basic earnings per average common share attributable to OGE Energy common shareholders	$3.60	$3.50	$3.03
Diluted earnings per average common share attributable to OGE Energy common shareholders	$3.58	$3.45	$2.99
Dividends declared per common share	$1.5950	$1.5175	$1.4625

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)	2012	2011	2010
OG&E (Electric Utility)	$489.4	$472.3	$413.7
Enogex (Natural Gas Midstream Operations)			
Natural gas transportation and storage (A)	45.1	56.4	60.4
Natural gas gathering and processing	140.5	118.7	123.9
Other Operations (B)	1.9	(0.7)	(4.1)
Consolidated operating income	$676.9	$646.7	$593.9

(A) During the third quarter of 2012, the operations and activities of EER were fully integrated with those of Enogex through the creation of a new commodity management organization. The operations of EER, including asset management activities, have been included in the natural gas transportation and storage segment and have been restated for all prior periods presented.

(B) Other Operations primarily includes the operations of the holding company and consolidating eliminations.

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

OG&E (Electric Utility)

Year ended December 31 (Dollars in millions)	2012	2011	2010
Operating revenues	$2,141.2	$2,211.5	$2,109.9
Cost of goods sold	879.1	1,013.5	1,000.2
Gross margin on revenues	1,262.1	1,198.0	1,109.7
Other operation and maintenance	446.3	436.0	418.1
Depreciation and amortization	248.7	216.1	208.7
Taxes other than income	77.7	73.6	69.2
Operating income	489.4	472.3	413.7
Interest income	0.2	0.5	0.1
Allowance for equity funds used during construction	6.2	20.4	11.4
Other income	8.0	8.0	6.5
Other expense	4.3	8.4	1.6
Interest expense	124.6	111.6	103.4
Income tax expense	94.6	117.9	111.0
Net income	$280.3	$263.3	$215.7
Operating revenues by classification			
Residential	$878.0	$943.5	$894.8
Commercial	523.5	531.3	521.0
Industrial	206.8	216.0	212.5
Oilfield	163.4	165.1	162.8
Public authorities and street light	202.4	207.4	200.8
Sales for resale	54.9	65.3	65.8
System sales revenues	2,029.0	2,128.6	2,057.7
Off-system sales revenues	36.5	36.2	21.7
Other	75.7	46.7	30.5
Total operating revenues	$2,141.2	$2,211.5	$2,109.9
MWH sales by classification (In millions)			
Residential	9.1	9.9	9.6
Commercial	7.0	6.9	6.7
Industrial	4.0	3.9	3.8
Oilfield	3.3	3.2	3.1
Public authorities and street light	3.3	3.2	3.0
Sales for resale	1.3	1.4	1.4
System sales	28.0	28.5	27.6
Off-system sales	1.4	1.0	0.5
Total sales	29.4	29.5	28.1
Number of customers	798,110	789,146	782,558
Weighted-average cost of energy per kilowatt-hour - cents			
Natural gas	2.930	4.328	4.638
Coal	2.310	2.064	1.911
Total fuel	2.437	2.897	3.012
Total fuel and purchased power	2.806	3.215	3.309
Degree days (A)			
Heating - Actual	2,667	3,359	3,528
Heating - Normal	3,349	3,631	3,631
Cooling - Actual	2,561	2,776	2,328
Cooling - Normal	2,092	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.

2012 compared to 2011. OG&E's operating income increased $17.1 million, or 3.6 percent, in 2012 as compared to 2011 primarily due to a higher gross margin partially offset by higher other operation and maintenance expense and higher depreciation and amortization expense.

Gross Margin

Operating revenues were $2,141.2 million in 2012 as compared to $2,211.5 million in 2011, a decrease of $70.3 million, or 3.2 percent. Cost of goods sold was $879.1 million in 2012 as compared to $1,013.5 million in 2011, a decrease of $134.4 million, or 13.3 percent. Gross margin was $1,262.1 million in 2012 as compared to $1,198.0 million in 2011, an increase of $64.1 million, or 5.4 percent. The below factors contributed to the change in gross margin:

	$ Change (In millions)
Price variance (A)	$54.1
Wholesale transmission revenue (B)	28.5
New customer growth	11.5
Non-residential demand and related revenues	4.9
Enogex transportation credit (C)	3.3
Arkansas rate increase	2.8
Oklahoma rate increase	2.7
Renewal of wholesale contract with customer	1.3
Other	0.3
Quantity variance (primarily weather)	(45.3)
Change in gross margin	$64.1

(A) Increased due to revenues from the recovery of investments, including the Crossroads wind farm and smart grid.

(B) Increased 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.

(C) Increased due to a credit to OG&E's customers in 2011 related to the settlement of OG&E's 2009 fuel adjustment clause review.

Cost of goods sold for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was $642.4 million in 2012 as compared to $775.0 million in 2011, a decrease of $132.6 million, or 17.1 percent, primarily due to lower natural gas prices. OG&E's electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for OG&E and its customers. In 2012, OG&E's fuel mix was 52 percent coal, 42 percent natural gas and six percent wind. In 2011, OG&E's fuel mix was 58 percent coal, 39 percent natural gas and three percent wind. Purchased power costs were $223.0 million in 2012 as compared to $230.7 million in 2011, a decrease of $7.7 million, or 3.3 percent, primarily due to a decrease in cogeneration purchases and purchases in the energy imbalance service market due to milder weather partially offset by an increase in short-term power purchases. Transmission related charges were $13.7 million in 2012 as compared to $7.8 million in 2011, an increase of $5.9 million, or 75.6 percent, primarily due to higher SPP charges for the base plan projects of other utilities.

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 $446.3 million in 2012 as compared to $436.0 million in 2011, an increase of $10.3 million, or 2.4 percent. The below factors contributed to the change in other operations and maintenance expense:

	$ Change (In millions)
Salaries and wages (A)	$6.4
Contract professional and technical services (related to smart grid) (B)	4.2
Employee benefits (C)	3.4
Administration and assessment fees (primarily SPP and North American Electric Reliability Corporation)	3.4
Wind farm lease expense (primarily Crossroads) (B)	3.0
Injuries and damages	1.9
Ongoing maintenance at power plants (B)	1.9
Software (primarily smart grid) (B)	1.8
Other	0.2
Temporary labor	(1.7)
Uncollectibles	(2.4)
Vegetation management (primarily system hardening) (B)	(3.0)
Allocations from holding company (primarily lower contract professional services and lower payroll and benefits)	(3.1)
Capitalized labor	(5.7)
Change in other operation and maintenance expense	$10.3

(A) Increased primarily due to salary increases and an increase in incentive compensation expense partially offset by lower headcount in 2012 and a decrease in overtime expense.
(B) Includes costs that are being recovered through a rider.
(C) Increased primarily due to an increase in worker's compensation accruals, an increase in medical expense and an increase in postretirement medical expense partially offset by a decrease in pension expense.

Depreciation and amortization expense was $248.7 million in 2012 as compared to $216.1 million in 2011, an increase of $32.6 million, or 15.1 percent, primarily due to additional assets being placed in service throughout 2011 and 2012, including the Crossroads wind farm, which was fully in service in January 2012, the Sooner-Rose Hill and Sunnyside-Hugo transmission projects, which were fully in service in April 2012, and the smart grid project which was completed in late 2012.

Additional Information

Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction was $6.2 million in 2012 as compared to $20.4 million in 2011, a decrease of $14.2 million, or 69.6 percent, primarily due to higher levels of construction costs for the Crossroads wind farm in 2011.

Other Income. Other income was $8.0 million in both 2012 and 2011. Factors affecting other income included an increased margin of $8.8 million recognized in the guaranteed flat bill program in 2012 as a result of milder weather offset by a decrease of $8.9 million related to the benefit associated with the tax gross-up of allowance for equity funds used during construction.

Other Expense. Other expense was $4.3 million in 2012 as compared to $8.4 million in 2011, a decrease of $4.1 million, or 48.8 percent primarily due to a decrease in charitable contributions.

Interest Expense. Interest expense was $124.6 million in 2012 as compared to $111.6 million in 2011, an increase of $13.0 million, or 11.6 percent, primarily due to a $6.9 million increase in interest expense related to lower allowance for borrowed funds used during construction costs for the Crossroads wind farm in 2011 and a $5.5 million increase in interest expense related to the issuance of long-term debt in May 2011.

Income Tax Expense. Income tax expense was $94.6 million in 2012 as compared to $117.9 million in 2011, a decrease of $23.3 million, or 19.8 percent. The decrease in income tax expense was primarily due to an increase in the amount of Federal renewable energy tax credits recognized associated with the Crossroads wind farm and lower pre-tax income in 2012 as compared to 2011.

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

Operating revenues were $2,211.5 million in 2011 as compared to $2,109.9 million in 2010, an increase of $101.6 million, or 4.8 percent. Cost of goods sold was $1,013.5 million in 2011 as compared to $1,000.2 million in 2010, an increase of $13.3 million, or 1.3 percent. 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 below factors contributed to the change in gross margin:

	$ Change (In millions)
Quantity variance (primarily weather)	$27.4
Price variance (A)	23.9
Transmission revenue (B)	15.3
New customer growth	13.1
Arkansas rate increase	6.0
Non-residential demand and related revenues	5.0
Renewal of wholesale contract with customer	3.1
Other	0.2
Enogex transportation credit (C)	(5.7)
Change in gross margin	$88.3

(A) Increased due to revenues from the recovery of investments, including the Windspeed transmission line, Oklahoma demand program, smart grid, system hardening, storm recovery, the Crossroads wind farm and the OU Spirit wind farm, and higher revenues from industrial and oilfield customers.

(B) Increased 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.

(C) Decreased due to a credit to OG&E's customers in 2011 related to the settlement of OG&E's 2009 fuel adjustment clause review.

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.

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 below factors contributed to the change in other operations and maintenance expense:

	$ Change (In millions)
Allocations from holding company (A)	$15.5
Salaries and wages (B)	12.1
Other marketing and sales expense (primarily demand-side management initiatives) (C)	4.6
Uncollectible expense	3.1
Fleet transportation expense (primarily higher fuel costs in 2011)	1.6
Temporary labor expense	1.3
Administration and assessment fees (primarily SPP)	1.2
Vegetation management (primarily system hardening) (C)	(2.9)
Other	(3.8)
Injuries and damages (primarily higher reserves on claims in 2010)	(5.0)
Employee benefits (D)	(9.8)
Change in other operation and maintenance expense	$17.9

(A) Increased primarily related to payroll and benefits expense, contract technical and construction services and contract professional services.

(B) Increased primarily due to salary increases in 2011, increased incentive compensation expense and increased overtime expense primarily due to storms in April and August 2011.

(C) Includes costs that are being recovered through a rider.

(D) Decreased 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.

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 the Crossroads wind farm in 2011.

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 the Crossroads wind farm; 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.

Enogex (Natural Gas Midstream Operations)

2012	Natural Gas Transportation and Storage	Natural Gas Gathering and Processing	Eliminations	Total
(In millions)				
Operating revenues	$639.5	$1,222.6	$(253.5)	$1,608.6
Cost of goods sold	504.9	868.7	(253.5)	1,120.1
Gross margin on revenues	134.6	353.9	—	488.5
Other operation and maintenance	49.8	123.1	—	172.9
Depreciation and amortization	24.0	84.8	—	108.8
Impairment of assets	—	0.4	—	0.4
Gain on insurance proceeds	—	(7.5)	—	(7.5)
Taxes other than income	15.7	12.6	—	28.3
Operating income	$45.1	$140.5	$—	$185.6

2011	Natural Gas Transportation and Storage	Natural Gas Gathering and Processing	Eliminations	Total
(In millions)				
Operating revenues	$880.1	$1,167.1	$(260.1)	$1,787.1
Cost of goods sold	736.0	870.7	(260.1)	1,346.6
Gross margin on revenues	144.1	296.4	—	440.5
Other operation and maintenance	50.7	111.8	—	162.5
Depreciation and amortization	22.0	55.6	—	77.6
Impairment of assets	—	6.3	—	6.3
Gain on insurance proceeds	—	(3.0)	—	(3.0)
Taxes other than income	15.0	7.0	0.1	22.1
Operating income	$56.4	$118.7	$(0.1)	$175.0

2010	Natural Gas Transportation and Storage	Natural Gas Gathering and Processing	Eliminations	Total
(In millions)				
Operating revenues	$984.8	$1,005.6	$(282.7)	$1,707.7
Cost of goods sold	834.5	733.3	(282.7)	1,285.1
Gross margin on revenues	150.3	272.3	—	422.6
Other operation and maintenance	53.8	91.5	—	145.3
Depreciation and amortization	21.2	50.1	—	71.3
Impairment of assets	0.7	0.4	—	1.1
Taxes other than income	14.2	6.4	—	20.6
Operating income	$60.4	$123.9	$—	$184.3

Operating Data			
Year ended December 31	2012	2011	2010
Gathered volumes – TBtu/d	1.41	1.36	1.32
Incremental transportation volumes – TBtu/d (A)	0.67	0.58	0.40
Total throughput volumes – TBtu/d	2.08	1.94	1.72
Natural gas processed – TBtu/d	0.98	0.79	0.82
Condensate sold – million gallons	35	27	24
Average condensate sales price per gallon	$1.95	$2.09	$1.81
NGLs sold (keep-whole) – million gallons	162	167	187
NGLs sold (purchased for resale) – million gallons	667	487	470
NGLs sold (percent-of-liquids) – million gallons	24	25	26
NGLs sold (percent-of-proceeds) – million gallons	14	6	5
Total NGLs sold – million gallons	867	685	688
Average NGLs sales price per gallon	$0.89	$1.16	$0.96
Average natural gas sales price per MMBtu	$2.79	$4.08	$4.24

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

2012 compared to 2011. Enogex's operating income increased $10.6 million, or 6.1 percent, in 2012 as compared to 2011. This increase was primarily due to a higher gross margin, a higher gain on insurance proceeds related to the reimbursement of costs incurred to replace the damaged train at the Cox City natural gas processing plant discussed below and lower impairment of assets partially offset by higher other operation and maintenance expense, higher depreciation and amortization expense and higher taxes other than income. The higher gross margin related to (i) increased gathering rates and volumes associated with ongoing expansion projects and increased volumes from gas gathering assets acquired in November 2011 and August 2012 and (ii) increased inlet volumes resulting from the return to full service of the Cox City natural gas processing plant in September 2011, the South Canadian natural gas processing plant, which was placed in service in December 2011, and the Wheeler natural gas processing plant, which was placed in service in August 2012. These increases in gross margin were partially offset by lower average natural gas and NGLs prices. In 2012, imbalance volume changes and realized margin on physical gas long/short positions decreased the gross margin by $7.5 million, net of corresponding imbalance and fuel tracker balances and the impact of the recovery of prior years' under-recovered fuel positions during 2012.

Other operation and maintenance expense increased $10.4 million, or 6.4 percent, primarily due to:

- increased payroll and benefits costs due to increased headcount to support business growth; and
- increased rental expense on compression due to leases acquired in the August 2012 gas gathering acquisition partially offset by the reduction of rental payments on the Atoka plant, which was taken out of service in August 2011.

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

- decreased costs for soil remediation projects; and
- lower contract technical and professional services expense and materials and supplies expense due to a decrease in non-capital projects during 2012.

Depreciation and amortization expense increased $31.2 million, or 40.2 percent, primarily due to additional assets placed in service throughout 2011 and 2012, including the gas gathering assets acquired in November 2011 and August 2012.
Impairment of assets decreased $5.9 million, or 93.7 percent, primarily due to an impairment of $5.0 million related to a management decision in August 2011 to use third-party processing exclusively for gathered volumes dedicated to the Atoka processing plant 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

was included in Net Income Attributable to Noncontrolling Interests in the Company's Consolidated Statement of Income.
Gain on insurance proceeds increased $4.5 million related to the reimbursement of costs incurred to replace the damaged train at the Cox City natural gas processing plant.

Taxes other than income increased $6.2 million, or 28.1 percent, primarily due to:

- sales tax of $3.5 million related to the acquisition of certain gas gathering assets in September 2012 as discussed in Note 3 of Notes to Consolidated Financial Statements; and
- increased ad valorem taxes resulting from additional assets placed in service throughout 2011 and 2012.

Natural Gas Transportation and Storage

The natural gas transportation and storage business contributed $134.6 million of Enogex's consolidated gross margin during 2012 as compared to $144.1 million during 2011, a decrease of $9.5 million or 6.6 percent. The transportation operations contributed $110.1 million of Enogex's consolidated gross margin during 2012 as compared to $118.8 million during 2011. The storage operations contributed $24.5 million of Enogex's consolidated gross margin during 2012 as compared to $25.3 million during 2011. Gross margin decreased primarily due to:

- lower volumes and realized margin on sales of physical natural gas long positions associated with transportation operations, which decreased the gross margin by $6.4 million, net of imbalances and fuel tracker balances;
- lower storage fees due to terminated contracts and renegotiated contracts with less favorable terms, which decreased the gross margin by $2.5 million;
- lower gains on storage sales during 2012, which decreased the gross margin by $1.9 million;
- lower crosshaul revenues in 2012 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 during 2011 partially offset by increased utilization of $1.3 million during 2012, which decreased the gross margin by $1.7 million; and
- lower transportation fees due to unbundling of transportation and gathering fees as contracts are renegotiated, which decreased the gross margin by $1.4 million.

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

- higher realized margin on hedging activity associated with natural gas storage inventory from storage, which increased the gross margin by $4.4 million; and
- higher transportation demand fees as a result of new contracts, which increased the gross margin by $2.3 million.

Other operation and maintenance expense for the natural gas transportation and storage business was $0.9 million, or 1.8 percent, lower during 2012 as compared to 2011 primarily due to lower contract technical and professional services expense and materials and supplies expense due to a decrease in non-capital projects during 2012 partially offset by increased payroll and benefits costs due to increased headcount to support business growth.

Natural Gas Gathering and Processing

The natural gas gathering and processing business contributed $353.9 million of Enogex's consolidated gross margin during 2012 as compared to $296.4 million during 2011, an increase of $57.5 million, or 19.4 percent. The gathering operations contributed $145.9 million of Enogex's consolidated gross margin during 2012 as compared to $125.2 million during 2011. The processing operations contributed $208.0 million of Enogex's consolidated gross margin during 2012 as compared to $171.2 million during 2011.

During 2012, Enogex realized a higher gross margin in its natural gas gathering and processing operations related to (i) increased gathering rates and volumes associated with ongoing expansion projects, primarily in the Granite Wash play, which has added richer natural gas to Enogex's system, and increased volumes from gas gathering assets acquired in November 2011 and August 2012, (ii) increased inlet volumes resulting from the return to full service of the Cox City natural gas processing plant in September 2011, the South Canadian natural gas processing plant, which was placed in service in December 2011, and the Wheeler natural gas processing plant, which was placed in service in

August 2012, and (iii) contract conversion of one of Enogex's five largest customer's Oklahoma production volumes to fixed fee effective July 1, 2011. These increases in the gathering and processing gross margin were partially offset by lower average natural gas and NGLs prices.

The above factors contributed to the increase in the natural gas gathering and processing gross margin as follows:

- an increased gross margin on keep-whole processing of $28.4 million;
- an increase in gathering fees associated with ongoing expansion projects and increased volumes from gas gathering assets, which increased the gross margin by $16.8 million;

- an increase in condensate revenues associated with higher condensate margins and volumes, which increased the gross margin by $14.2 million; and
- an increased gross margin on fixed-fee contracts of $8.4 million.

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

- an increase in the utilization of third-party processing as a result of (i) the Atoka processing plant being taken out of service in August 2011 and (ii) increased activity from western Oklahoma and Texas Panhandle expansion projects currently processed by third parties, which together decreased the gross margin by $6.2 million;
- a decrease in percent-of-liquids and percent-of-proceeds margins of $4.4 million; and
- lower volumes and realized margin on sales of physical natural gas long positions associated with gathering operations, which decreased the gross margin by $1.1 million, net of imbalances and fuel tracker obligations.

Other operation and maintenance expense for the natural gas gathering and processing business was $11.3 million, or 10.1 percent, higher during 2012 as compared to 2011 primarily due to:

- increased payroll and benefits costs due to increased headcount to support business growth; and
- increased rental expense on compression due to leases acquired in the August 2012 gas gathering acquisition partially offset by the reduction of rental payments on the Atoka plant, which was taken out of service in August 2011.

These increases in other operation and maintenance expense were partially offset by decreased costs for soil remediation projects.

Enogex Consolidated Information

Other Income. Enogex's consolidated other income was $1.0 million during 2012 as compared to $3.9 million during 2011, a decrease of $2.9 million, or 74.4 percent, due to the recognition in April 2011 of a gain related to the sale of the Harrah processing plant and the associated Wellston and Davenport gathering assets.

Other Expense. Enogex's consolidated other expense was $4.5 million during 2012 as compared to $1.3 million during 2011, an increase of $3.2 million due to higher non-cash losses on retirements of equipment during 2012.

Interest Expense. Enogex's consolidated interest expense was $32.6 million during 2012 as compared to $22.9 million during 2011, an increase of $9.7 million, or 42.4 percent, primarily due to:

- a decrease in capitalized interest during 2012 due to the completion of several large capital projects as compared to 2011;
- higher borrowings partially offset by repayments under Enogex's revolving credit agreement during 2012 as compared to 2011; and
- borrowings under Enogex's term loan during 2012 with no comparable item during 2011.

Income Tax Expense. Enogex's consolidated income tax expense was $45.7 million during 2012 as compared to $51.7 million during 2011, a decrease of $6.0 million, or 11.6 percent, primarily due to lower pre-tax income (net of noncontrolling interest) during 2012 as compared to 2011.

Noncontrolling Interest. Enogex's net income attributable to noncontrolling interest was $29.7 million during 2012 as compared to $20.8 million during 2011, an increase of $8.9 million or 42.8 percent, due to higher net income, the ArcLight group's increased ownership in Enogex Holdings as a result of the ArcLight group funding capital contributions at a disproportionate percentage to OGE Holdings throughout 2011 and an impairment recorded in August 2011 related to the Atoka processing plant.

Non-Recurring Items. During 2012, Enogex had an increase in net income of $4.6 million due to a gain on insurance proceeds related to the reimbursement of costs incurred to replace the damaged train at the Cox City natural gas processing plant partially offset by a decrease in net income of $2.1 million related to sales taxes on the assets acquired in the gas gathering acquisitions in August 2012, as discussed in Note 3 of Notes to Consolidated Financial Statements, which Enogex does not consider to be reflective of its ongoing performance. During 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.

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 2011, imbalance 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 balances 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 a management decision in August 2011 to use third-party processing exclusively for gathered volumes dedicated to the Atoka processing plant 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 was 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.

Natural Gas Transportation and Storage

The natural gas transportation and storage business contributed $144.1 million of Enogex's gross margin in 2011 as compared to $150.3 million in 2010, a decrease of $6.2 million, or 4.1 percent. The transportation operations contributed $118.8 million of Enogex's consolidated gross margin in 2011 as compared to $116.9 million in 2010. The storage operations contributed $25.3 million of Enogex's consolidated gross margin in 2011 as compared to $33.4 million in 2010. Gross margin decreased primarily due to:

- 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;
- 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 $4.4 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 in the natural gas transportation and storage gross margin were partially offset by:

- 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;
- more favorable results from Enogex's customer-focused risk management services, natural gas marketing activities and trading activities and the expiration of an unfavorable transportation contract, which increased the gross margin by $2.2 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.

Other operation and maintenance expense for the natural gas transportation and storage business was $3.1 million, or 5.8 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.

Natural Gas Gathering and Processing

The natural gas 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 natural gas 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. 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.

The above factors contributed to the increase in the natural gas gathering and processing gross margin as follows:

- an increase in condensate revenues associated with higher condensate prices and volumes, which increased the gross margin by $11.1 million;
- an increase in gathering fees associated with ongoing expansion projects, which increased the gross margin by $10.7 million;
- an increased gross margin on keep-whole processing of $4.8 million;
- an increased gross margin on percent-of-liquids and percent-of-proceeds contracts of $2.6 million; and
- an increased gross margin on fixed-fee contract of $1.3 million.

These increases in the natural gas 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 natural gas 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.

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. During 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 Enogex's natural gas storage inventory at the lower of cost or market value. The offsetting gains from the sale of withdrawals from inventory were realized during the first quarter of 2012.

Non-GAAP Financial Measure

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

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

Enogex provides a reconciliation of EBITDA to net income attributable to Enogex Holdings, which Enogex considers to be its most directly comparable financial measure as calculated and presented in accordance with GAAP. The non-GAAP financial measure of EBITDA should not be considered as an alternative to GAAP net income attributable to Enogex Holdings. EBITDA is not a presentation made in accordance with GAAP and has important limitations as an analytical tool. EBITDA should not be considered in isolation or as a substitute for analysis of Enogex's results as reported under GAAP. Because EBITDA excludes some, but not all, items that affect net income and is defined differently by different companies in Enogex's industry, Enogex's definition of EBITDA may not be comparable to a similarly titled measure of other companies.

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

Reconciliation of EBITDA to net income attributable to Enogex Holdings			
(In millions)	2012	2011	2010
Net income attributable to Enogex Holdings	$147.8	$155.9	$476.1
Add:			
Interest expense, net	32.6	22.9	30.3
Income tax expense (A)	0.2	0.2	(325.0)
Depreciation and amortization expense (B)	111.6	77.2	70.2
EBITDA	$292.2	$256.2	$251.6
OGE Energy's portion	$236.6	$222.9	$248.8

(A) As of November 1, 2010, Enogex Holdings' earnings are no longer subject to tax (other than Texas state margin taxes) and are taxable at the individual partner level.

(B) Includes amortization of certain customer-based intangible assets associated with the acquisition from Cordillera in November 2011, which is included in gross margin for financial reporting purposes.

Off-Balance Sheet Arrangement

OG&E Railcar Lease Agreement

OG&E has a noncancellable operating lease with purchase options, covering 1,389 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.

On January 11, 2012, OG&E executed a five-year lease agreement for 135 railcars to replace railcars that have been taken out of service or destroyed. 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.

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

Working Capital

Working capital is defined as the amount by which current assets exceed current liabilities. The Company's working capital requirements are driven generally by changes in accounts receivable, accounts payable, commodity prices, credit extended to, and the timing of collections from, customers, the level and timing of spending for maintenance and expansion activity, inventory levels and fuel recoveries.

The balance of Accounts Receivable, Net and Accrued Unbilled Revenues was $352.7 million and $381.8 million at December 31, 2012 and 2011, respectively, a decrease of $29.1 million, or 7.6 percent, primarily due to a decrease in billings to OG&E's customers in 2012 due to milder weather in 2012, a decrease at Enogex due to lower natural gas sales volumes and prices and the timing of customer payments received partially offset by higher transmission revenue and increased rates at OG&E.

The balance of Accounts Payable was $396.7 million and $388.0 million at December 31, 2012 and 2011, respectively, an increase of $8.7 million, or 2.2 percent, primarily due to increased NGLs volumes at Enogex partially offset by lower NGLs prices at Enogex, a decrease in accruals and the timing of ad valorem payments.

Cash Flows

				2012 vs. 2011		2011 vs. 2010	
Year ended December 31 (In millions)	2012	2011	2010	$ Change	% Change	$ Change	% Change
Net cash provided from operating activities	$1,046.1	$833.9	$782.5	$212.2	25.4 %	$51.4	6.6 %
Net cash used in investing activities	(1,192.6)	(1,395.8)	(846.1)	203.2	(14.6)%	(549.7)	65.0 %
Net cash provided from financing activities	143.7	564.2	7.8	(420.5)	(74.5)%	556.4	*

* Percentage is greater than 100 percent.

Operating Activities

The increase of $212.2 million, or 25.4 percent, in net cash provided from operating activities in 2012 as compared to 2011 was primarily due to:

- higher fuel recoveries at OG&E in 2012 as compared to 2011;
- an increase in cash received in 2012 from transmission revenue and the recovery of investments including the Crossroads wind farm and smart grid partially offset by milder weather in 2012; and
- an increase in gathered volumes and NGLs volumes at Enogex during 2012 as compared to 2011 partially offset by lower natural gas and NGLs prices in 2012 as compared to 2011.

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;

These increases in net cash provided from operating activities was 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.

Investing Activities

The decrease of $203.2 million, or 14.6 percent, in net cash used in investing activities in 2012 as compared to 2011 was primarily due to lower levels of capital expenditures in 2012 related to the Crossroads wind farm at OG&E and lower levels of capital expenditures related to gathering and processing expansion projects at Enogex.

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 the Crossroads wind farm at OG&E and gathering and processing expansion projects at Enogex.

Financing Activities

The decrease of $420.5 million, or 74.5 percent, in net cash provided from financing activities in 2012 as compared to 2011 was primarily due to:

- lower contributions from the ArcLight group during 2012 as compared to 2011;
- higher borrowings under Enogex's revolving credit agreement during 2011; and
- repayments of Enogex's line of credit during 2012.

These decreases in net cash provided from financing activities were partially offset by an increase in short-term debt borrowings during 2012 as compared to 2011.

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.

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 2013 through 2017 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)	2013	2014	2015	2016	2017
OG&E Base Transmission	$65	$50	$50	$50	$50
OG&E Base Distribution	175	175	175	175	175
OG&E Base Generation	80	75	75	75	75
OG&E Other	15	15	15	15	15
Total OG&E Base Transmission, Distribution, Generation and Other	335	315	315	315	315
OG&E Known and Committed Projects:					
Transmission Projects:					
Balanced Portfolio 3E Projects (A)	205	25	—	—	—
SPP Priority Projects (B)	165	110	—	—	—
SPP Integrated Transmission Projects (C)	5	5	—	40	40
Total Transmission Projects	375	140	—	40	40
Other Projects:					
Smart Grid Program	25	25	10	10	—
System Hardening	15	—	—	—	—
Environmental - low NOX burners	30	20	25	20	—
Total Other Projects	70	45	35	30	—
Total OG&E Known and Committed Projects	445	185	35	70	40
Total OG&E (D)	780	500	350	385	355
Enogex LLC Base Maintenance	50	55	55	55	55
Enogex LLC Known and Committed Projects:					
Western Oklahoma / Texas Panhandle Gathering Expansion	380	180	140	80	65
Other Gathering Expansion	25	15	10	10	10
Total Enogex LLC Known and Committed Projects	405	195	150	90	75
Total Enogex LLC (E)	455	250	205	145	130
OGE Energy	10	10	10	10	10
Total capital expenditures	$1,245	$760	$565	$540	$495

(A) Balanced Portfolio 3E includes three 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 $175 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

$115 million for OG&E, which is expected to be in service by mid-2014 and (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 $45 million for OG&E, which was placed in service in February 2013.

(B) 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. OG&E began construction on the Hitchland project in November 2012 and expects to begin construction on the Kansas project in June 2013.

(C) On January 31, 2012, the SPP approved the Integrated Transmission Plan Near Term and Integrated Transmission Plan 10-year projects. These plans include two projects to be built by OG&E: (i) construction of 47 miles of transmission line from OG&E's Gracemont substation in a northwestern direction to a companion transmission line to be built by American Electric Power to its Elk City substation at an estimated cost of $75 million for OG&E, which is expected to be in service by early 2018, and (ii) construction of 126 miles of transmission line from OG&E's Woodward District Extra High Voltage substation in a southeastern direction to OG&E's Cimarron substation and construction of a new substation on this transmission line, the Mathewson substation, at an estimated cost of $210 million for OG&E, which is expected to be in service by early 2021. On April 9, 2012, OG&E received a notice to construct these projects from the SPP. On June 26, 2012, OG&E responded to the SPP that OG&E will construct the projects discussed above and is moving forward with more detailed cost estimates that must be reviewed and approved by the SPP. OG&E and American Electric Power are currently in discussions regarding how much of the 94 mile Elk City to Gracemont transmission line will be built by OG&E and American Electric Power. American Electric Power has argued for a larger portion of such transmission line than the traditional 50 percent split. The capital expenditures related to these projects are presented in the summary of capital expenditures for known and committed projects above.

(D) The capital expenditures above exclude any environmental expenditures associated with:

- Pollution control equipment related to controlling SO2 emissions under the regional haze requirements due to the uncertainty regarding the approach and timing for such pollution control equipment. The SO2 emissions standards in the EPA's FIP 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 FIP is being challenged by OG&E and the state of Oklahoma. On June 22, 2012, OG&E was granted a stay of the FIP by the U.S. Court of Appeals for the Tenth Circuit, which delays the timing of required implementation of the SO2 emissions standards in the rule. The merits of the appeal have been fully briefed, and oral argument is scheduled to occur on March 6, 2013. Neither the outcome of the challenge to the FIP nor the timing of any required capital expenditures can be predicted with any certainty at this time, but such capital expenditures could be significant.
- Installation of control equipment for compliance with MATS by a deadline of April 16, 2015, with the possibility of a one-year extension. OG&E is currently planning to utilize activated carbon injection and low levels of dry sorbent injection at each of its five coal-fired units. Due to various uncertainties about the final design, the potential use of this technology relating to regional haze measures and the specifications for the control equipment, the resulting cost estimates currently range from $34 million to $72 million per unit.

OG&E is currently evaluating options to comply with environmental requirements. For further information, see "Environmental Laws and Regulations" below.

(E)

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 27, 2013 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, 2012. See the Company's Consolidated Statements of Capitalization and Note 16 of Notes to Consolidated Financial Statements for additional information.

(In millions)	2013	2014-2015	2016-2017	After 2017	Total
Maturities of long-term debt (A)	$0.2	$550.4	$235.4	$2,070.1	$2,856.1
Operating lease obligations					
OG&E railcars	3.2	5.5	27.3	—	36.0
OG&E wind farm land leases	2.0	4.2	4.5	51.2	61.9
OGE Energy noncancellable operating lease	0.3	1.6	1.6	0.7	4.2
Enogex noncancellable operating leases	5.2	7.2	4.1	—	16.5
Total operating lease obligations	10.7	18.5	37.5	51.9	118.6
Other purchase obligations and commitments					
OG&E cogeneration capacity and fixed operation and maintenance payments	87.9	170.3	162.5	315.3	736.0
OG&E expected cogeneration energy payments	58.6	134.3	168.3	468.7	829.9
OG&E minimum fuel purchase commitments	405.0	519.8	—	—	924.8
OG&E expected wind purchase commitments	57.5	116.9	120.6	838.0	1,133.0
OG&E long-term service agreement commitments	8.0	34.5	12.6	53.0	108.1
EER commitments	11.9	15.5	0.8	—	28.2
Total other purchase obligations and commitments	628.9	991.3	464.8	1,675.0	3,760.0
Total contractual obligations	639.8	1,560.2	737.7	3,797.0	6,734.7
Amounts recoverable through fuel adjustment clause (B)	(524.3)	(776.5)	(316.2)	(1,306.7)	(2,923.7)
Total contractual obligations, net	$115.5	$783.7	$421.5	$2,490.3	$3,811.0

(A) Maturities of the Company's long-term debt during the next five years consist of $0.2 million, $300.2 million, $250.2 million, $110.2 million and $125.2 million in years 2013, 2014, 2015, 2016 and 2017, respectively.

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

OG&E also has 440 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, 2012, 42.3 percent of the Pension Plan investments were in listed common stocks with the balance primarily invested in U.S Government securities, bonds, debentures and notes, a commingled fund and a common collective trust as presented in Note 14 of Notes to Consolidated Financial Statements. In 2012, asset returns on the Pension Plan were 10.6 percent due to the gains in fixed income and equity investments. During the same time, corporate bond yields, which are used in determining the discount rate for future pension obligations, have continued to decline. During 2012 and 2011, OGE Energy made contributions to its Pension Plan of $35 million and $50 million, respectively, 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 2013, OGE Energy expects to 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, 2012 and 2011. 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)	2012	2011	2012	2011	2012	2011
Benefit obligations	$(747.1)	$(697.7)	$(14.5)	$(13.3)	$(301.0)	$(280.6)
Fair value of plan assets	626.0	589.8	—	—	59.6	61.0
Funded status at end of year	$(121.1)	$(107.9)	$(14.5)	$(13.3)	$(241.4)	$(219.6)

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 November 2012 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 $0.4175 per share from $0.3925 per share effective with the Company's first quarter 2013 dividend.

Security Ratings