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

(Mark One)
x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2013

OR

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

Commission File Number: 1-12579

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

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

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

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

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

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
☑ Yes o No

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

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 ☑	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

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

At June 28, 2013, 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 $6,733,312,753 based on the number of shares held by non-affiliates (197,457,852) and the reported closing market price of the common stock on the New York Stock Exchange on such date of $34.10.

At January 31, 2014, there were 198,620,521 shares of common stock, par value $0.01 per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The Proxy Statement for the Company's 2014 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, 2013

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GLOSSARY OF TERMS

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

Abbreviation	Definition
401(k) Plan	Qualified defined contribution retirement plan
APSC	Arkansas Public Service Commission
ArcLight group	Bronco Midstream Holdings, LLC, Bronco Midstream Holdings II, LLC, collectively
ASC	Financial Accounting Standards Board Accounting Standards Codification
Atoka	Atoka Midstream LLC joint venture
BART	Best available retrofit technology
CenterPoint	CenterPoint Energy Resources Corp., wholly-owned Subsidiary of CenterPoint Energy, Inc.
Code	Internal Revenue Code of 1986
Company	OGE Energy Corp, collectively with its subsidiaries and Enable Midstream Partners
DOJ	U.S. Department of Justice
Dry Scrubbers	Dry flue gas desulfurization units with spray dryer absorber
Enable	Enable Midstream Partners, LP, partnership between OGE Energy, the ArcLight Group and CenterPoint Energy, Inc. formed to own and operate the midstream businesses of OGE Energy and CenterPoint
Enogex Holdings	Enogex Holdings LLC, the parent company of Enogex LLC and a majority-owned subsidiary of OGE Holdings, LLC (prior to May 1, 2013)
Enogex, LLC	Enogex, LLC collectively with its subsidiaries (effective June 30, 2013, the name was changed to Enable Oklahoma Intrastate Transmission, LLC)
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
MMBtu	Million British thermal unit
MMcf/d	Million cubic feet per day
MRT	CenterPoint Energy - Mississippi River Transmission, LLC, a Delaware limited liability company
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, wholly-owned subsidiary of OGE Energy Corp
OGE Holdings	OGE Enogex Holdings, LLC, wholly-owned subsidiary of OGE Energy Corp, parent company of Enogex Holdings (prior to May 1, 2013) and 28.5 percent owner of Enable Midstream Partners
OSHA	Federal Occupational Safety and Health Act of 1970
Pension Plan	Qualified defined benefit retirement plan
PRM	Price risk management
PUD Staff	Public Utility Division Staff of the Oklahoma Corporation Commission
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;
- the timing and extent of changes in commodity prices, particularly natural gas and NGLs, the competitive effects of the available pipeline capacity in the regions Enable serves, and the effects of geographic and seasonal commodity price differentials, including the effects of these circumstances on re-contracting available capacity on Enable's interstate pipelines;
- the timing and extent of changes in the supply of natural gas, particularly supplies available for gathering by Enable's gathering and processing business and transporting by Enable interstate pipelines, including the impact of natural gas and NGLs prices on the level of drilling and production activities in the regions Enable serves;
- business conditions in the energy and natural gas midstream industries, including the demand for natural gas, NGLs, crude oil and midstream services;
- 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;
- difficulty in making accurate assumptions and projections regarding future revenues and costs associated with the Company's equity investment in Enable that the Company does not control;
- the risk that Enable may not be able to successfully integrate the operations of Enogex LLC and the businesses contributed by CenterPoint as discussed in Note 3; 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 two business segments: (i) electric utility and (ii) natural gas midstream operations. For a discussion of the change in the Company's business segments due to the formation of Enable, see Note 14 of Notes to Condensed Consolidated Financial Statements.

For periods prior to May 1, 2013, the Company consolidated Enogex Holdings in its Condensed 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.

Effective May 1, 2013, OGE Energy, the ArcLight group and CenterPoint Energy, Inc., formed Enable Midstream Partners, LP to own and operate the midstream businesses of OGE Energy and CenterPoint. In the formation transaction, OGE Energy and ArcLight group contributed Enogex LLC to Enable and the Company deconsolidated its previously held investment in Enogex Holdings and acquired an equity interest in Enable. The Company determined that its contribution of Enogex LLC to Enable met the requirements of being in substance real estate and was recorded at historical cost. The general partner of Enable is equally controlled by CenterPoint and OGE Energy, who each have 50 percent of the management rights. Based on the 50/50 management ownership, with neither company having control, effective May 1, 2013, OGE Energy began accounting for its interest in Enable using the equity method of accounting. At December 31, 2013, OGE Energy, through its wholly owned subsidiary OGE Holdings, holds 28.5 percent of the limited partner interests in Enable. OGE Energy also owns a 60 percent interest in any incentive distribution rights in Enable. Incentive distribution rights are expected to entitle the holder to increasing percentages, up to a maximum of 50 percent, of the cash distributed by Enable in excess of the target quarterly distributions to be set in connection with Enable's initial public offering. On November 26, 2013, Enable filed a registration statement on Form S-1 related to the proposed initial public offering of limited partnership interests that will have the effect of making Enable a publicly traded master limited partnership.

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.

The natural gas midstream operations segment consists of the Company's investment in Enable. Enable is engaged in the business of gathering, processing, transporting and storing natural gas. Enable's natural gas gathering and processing assets are strategically located in four states and serve natural gas production from shale developments in the Anadarko, Arkoma and Ark-La-Tex basins. Enable also owns an emerging crude oil gathering business in the Bakken shale formation that commenced initial operations in November 2013. Enable is continuing to construct additional crude oil gathering capacity in this area. Enable's natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

The Company completed a 2-for-1 stock split of the Company's common stock effective July 1, 2013. All share and per share amounts within this Form 10-K reflect the effects of the stock split.

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.

Enable's primary business objective is to practice operational excellence and to grow its business responsibly, increasing the amount of cash distributions made to its unitholders over time while maintaining financial stability. Strategies to accomplish this objective include capitalizing on organic growth opportunities and leveraging the scale of its existing assets, utilizing long-term, fee-based contracts to minimize direct commodity price exposure and maintaining strong customer relationships to attract new volumes and expand beyond its existing footprint and business lines. Enable also plans to grow through accretive acquisitions and disciplined development.

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 of approximately 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 2013, 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 2013 from sales in Oklahoma and the remainder from sales in Arkansas.

OG&E's system control area peak demand in 2013 was 6,341 MWs on June 27, 2013. OG&E's load responsibility peak demand was 5,806 MWs on June 27, 2013. As reflected in the table below and in the operating statistics that follow, there were 28.2 million MWH system sales in 2013, 28.0 million MWH system sales in 2012 and 28.5 million MWH system sales in 2011. Variations in system sales for the three years are reflected in the following table:

Year ended December 31	**2013**	**2013 vs. 2012 Increase**	2012	2012 vs. 2011 Decrease	2011
System sales - millions of MWHs	**28.2**	**0.7%**	28.0	(1.8)%	28.5

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	**2013**	2012	2011
ELECTRIC ENERGY *(Millions of MWH)*			
Generation (exclusive of station use)	**24.2**	26.3	26.7
Purchased	**6.3**	5.0	4.9
Total generated and purchased	**30.5**	31.3	31.6
OG&E use, free service and losses	**(1.9)**	(1.9)	(2.1)
Electric energy sold	**28.6**	29.4	29.5
ELECTRIC ENERGY SOLD *(Millions of MWH)*			
Residential	**9.4**	9.1	9.9
Commercial	**7.1**	7.0	6.9
Industrial	**3.9**	4.0	3.9
Oilfield	**3.4**	3.3	3.2
Public authorities and street light	**3.2**	3.3	3.2
Sales for resale	**1.2**	1.3	1.4
System sales	**28.2**	28.0	28.5
Off-system sales	**0.4**	1.4	1.0
Total sales	**28.6**	29.4	29.5
ELECTRIC OPERATING REVENUES *(In millions)*			
Residential	**$ 901.4**	$ 878.0	$ 943.5
Commercial	**554.2**	523.5	531.3
Industrial	**220.6**	206.8	216.0
Oilfield	**176.4**	163.4	165.1
Public authorities and street light	**214.3**	202.4	207.4
Sales for resale	**59.4**	54.9	65.3
System sales revenues	**2,126.3**	2,029.0	2,128.6
Off-system sales revenues	**14.7**	36.5	36.2
Other	**121.2**	75.7	46.7
Total operating revenues	**$ 2,262.2**	$ 2,141.2	$ 2,211.5
ACTUAL NUMBER OF ELECTRIC CUSTOMERS *(At end of period)*			
Residential	**690,390**	683,214	675,806
Commercial	**90,279**	88,772	87,480
Industrial	**2,921**	2,957	2,991
Oilfield	**6,431**	6,426	6,451
Public authorities and street light	**16,877**	16,695	16,374
Sales for resale	**42**	46	44
Total	**806,940**	798,110	789,146
AVERAGE RESIDENTIAL CUSTOMER SALES			
Average annual revenue	**$ 1,312.59**	$ 1,292.11	$ 1,401.84
Average annual use (kilowatt-hour)	**13,718**	13,477	14,738
Average price per kilowatt-hour (cents)	**$ 9.57**	$ 9.59	$ 9.51

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 2013, 85 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight percent to the APSC and seven 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

Crossroads Wind Farm

As previously reported, OG&E signed memoranda of understanding in February 2010 for approximately 197.8 megawatts 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 megawatts. 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 April 15, 2013, the APSC issued an order authorizing OG&E to recover the Arkansas portion of the cost to construct the Crossroads wind farm, effective retroactively to August 1, 2012. The costs are being recovered through the Energy Cost Recovery Rider.

Fuel Adjustment Clause Review for Calendar Year 2011

The OCC routinely reviews the costs recovered from customers through OG&E’s fuel adjustment clause. 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 information and documents in response to the OCC's application 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. On April 9, 2013, the OCC administrative law judge recommended that the OCC find that for the calendar year 2011 OG&E's electric generation, purchased power and fuel procurement processes and costs were prudent. On June 18, 2013, the OCC issued an order approving the administrative law judge’s recommendation.

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. On May 29, 2013, the Governor signed House Bill 1932 into law which establishes a right of first refusal for Oklahoma incumbent transmission owners, including OG&E, to build new transmission projects with voltages under 300 kilovolts that interconnect to those incumbent entities' existing facilities. OG&E believes this law is consistent with the language of Order No. 1000.

On July 18, 2013, the FERC issued an order on the SPP's Order No. 1000 compliance filing. This order accepted in part and rejected in part the SPP's plan for complying with Order No. 1000. The FERC rejected the SPP's plan to retain the right of first refusal for projects that would operate between 100 kilovolts and 300 kilovolts. However, the FERC clarified that a right of first refusal was appropriate in certain circumstances. It is not clear how the FERC's order will relate to the recently enacted Oklahoma law addressing a right of first refusal for lower voltages. On November 15, 2013, SPP made its FERC compliance filing, as required by the July 18, 2013 order. The SPP changes to its tariff and Membership Agreement included provisions that (i) clarify that facilities between 100 kilovolts and 300 kilovolts would be subject to the competitive selection process, (ii) only allow certain evidence, such as state laws (like House Bill 1932) and the holders of existing rights of way, to be considered during the competitive selection process and not earlier in the process; (iii) apply a right of first refusal to transmission projects needed for reliability within three years in certain situations; and (iv) revise the tariff’s competitive selection process, including changes to the criteria for identifying qualifying transmission owners, the requirements for submission of information by transmission owners seeking to participate in competitive selections, and the procedures that govern the competitive selection process.

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.

Fuel Adjustment Clause Review for Calendar Year 2012

On July 31, 2013, the OCC Staff filed an application to review OG&E's fuel adjustment clause for calendar year 2012, including the prudence of OG&E's electric generation, purchased power and fuel procurement costs. OG&E filed the necessary information and documents needed to satisfy the OCC's minimum filing requirement rules on October 9, 2013. A hearing on this matter is scheduled for April 24, 2014.

Request for Modification to Previous Orders

On August 2, 2013, OG&E filed an application at the OCC seeking to make minor modifications to three previous OCC orders. The purpose of the application was to address the timing of certain requirements contained in those orders. OG&E's application proposed to address these issues in OG&E's next general rate case thus avoiding the cost associated with a rate case filing now and benefiting customers by deferring the recovery of certain costs identified in the previous orders. On September 3, 2013, the PUD Staff filed a motion to dismiss OG&E's application. PUD Staff requested that the OCC dismiss OG&E's application and issue an order requiring OG&E to file a rate case for the 2012 test year.

On September 11, 2013, the PUD Staff withdrew their motion to dismiss OG&E's application and on September 12, 2013, filed an application requesting a public hearing, review and possible adjustment of the rates and charges of OG&E based on the 2012 test year. To date, no procedural schedule has been established for either the OG&E application or the PUD Staff application.

Energy Efficiency Program Filing

On October 9, 2013 OG&E filed an application with the APSC requesting approval of interim modifications to approved Energy Efficiency Programs, new tariff revisions and the waiver of certain provisions of the Commission's Rules for Conservation and Energy Efficiency Programs.

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 rates sales outside of the SPP's energy imbalance service market. On May 2, 2013, the FERC issued an order accepting OG&E's June 2012 triennial market power update.

On December 30, 2013, OG&E submitted to the FERC a market-based rate change in status filing and a revised market-based rate tariff. The revised tariff will authorize OG&E to (i) sell electric energy and capacity at market-based rates without geographic restriction, and (ii) sell ancillary services in the SPP and Midcontinent Independent System Operator, Inc. markets. The primary goal of this filing was to implement the market-based rate authority OG&E needs to fully participate in SPP's Integrated Marketplace. OG&E requested that FERC issue an order on or before February 28, 2014 that accepts the revised market-based rate tariff to be effective on the date SPP's Integrated Marketplace goes into operation, which is expected to be March 1, 2014.

Section 206 Complaint

On November 26, 2013, Arkansas Electric Cooperative Corporation filed a complaint at the FERC against OG&E, arguing that the wholesale formula rate contract between OG&E and Arkansas Electric Cooperative Corporation (formerly between OG&E and Arkansas Valley Electric Cooperative) is unjust and unreasonable with respect to several items. After engaging in settlement discussions, OG&E and Arkansas Electric Cooperative Corporation have tentatively agreed to terms of a settlement and are jointly preparing an offer of settlement to be filed with FERC. OG&E believes the reduction in revenue will be less than $1.0 million per year.

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, 2013 and 2012, OG&E had regulatory assets of $427.9 million and $537.6 million, respectively, and regulatory liabilities of $254.4 million and $386.2 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 the actual cost of fuel and purchased power.

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 2013, 53 percent of the OG&E-generated energy was produced by coal-fired units, 40 percent by natural gas-fired units and seven percent by wind-powered units. Of OG&E's 6,785 total MW capability reflected in the table under Item 2. Properties, 3,798 MWs, or 56 percent, are from natural gas generation, 2,538 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)*	**2013**	2012	2011	2010	2009
Natural gas	**3.905**	2.930	4.328	4.638	3.696
Coal	**2.273**	2.310	2.064	1.911	1.747
Weighted average	**2.784**	2.437	2.897	3.012	2.474

The increase in the weighted average cost of fuel in 2013 as compared to 2012 was primarily due to higher gas prices. 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. These fuel costs are 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 2,538 MWs, are designed to burn low sulfur western sub-bituminous coal. OG&E has contracted for approximately 55 percent of its forecasted annual coal usage via multi-year contracts that expire in 2016 and the remainder of its forecasted 2014 usage via one-year contracts that expire in 2014. In 2013, OG&E purchased 7.8 million tons of coal from various Wyoming suppliers. The combination of all coal has a weighted average sulfur content of 0.21 percent. Based upon the average sulfur content and EPA certified emission data, OG&E's coal units have an approximate emission rate of 0.5 lbs. of SO2 per MMBtu. As discussed in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Environmental Laws and Regulations," emission limits are expected to become more stringent.

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

Natural Gas

OG&E has entered into multiple month term natural gas contracts for 31.5 percent of its 2014 annual forecasted natural gas requirements. Additional gas supplies to fulfill OG&E's remaining 2014 natural gas requirements will be acquired through additional requests for proposal in early to mid-2014, along with monthly and daily purchases, all of which are expected to be made at market prices.

OG&E utilizes natural gas storage service on Enable's and OneOK Gas Transmission's pipelines. The storage services allow OG&E to maximize the value of its generation assets. At December 31, 2013, OG&E had 2.1 million MMBtu's in natural gas storage valued at $7.6 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, EPA and comparable state statutes, whose purpose is to protect the safety and health of workers.

In addition, the OSHA hazard communication standard, the EPA Emergency Planning and 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 stored, used or produced in OG&E's operations and that this information be provided or made available 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 - ENABLE MIDSTREAM PARTNERS

Overview

Enable was formed on May 1, 2013, to own and operate the midstream businesses of OGE Energy and CenterPoint. References below to "a pro forma basis" include the combined operations of the midstream businesses of OGE Energy and CenterPoint for periods prior to May 1, 2013 and the operations of Enable subsequent to May 1, 2013. Enable is a large-scale, growth-oriented limited partnership formed to own, operate and develop strategically located natural gas and crude oil infrastructure assets. Enable serves key current and emerging production areas in the United States, including several premier, unconventional shale resource plays and local and regional end-user markets in the United States. Enable's operations include natural gas gathering, processing and fractionation services and crude oil gathering for its producer customers, and interstate and intrastate natural gas pipeline transportation and storage service to natural gas producers, utilities and industrial customers. A substantial portion of Enable's earnings are generated under long-term, fee-based agreements that minimize direct exposure to commodity price fluctuations.

Enable's natural gas gathering and processing assets are strategically located in four states and serve natural gas production from some of the most productive shale developments in the Anadarko, Arkoma and Ark-La-Tex basins. These basins have experienced a strong increase in investment and drilling activity by exploration and production companies in recent years. Enable also owns an emerging crude oil gathering business in the Bakken shale formation of the Williston Basin that commenced initial operations in November 2013. Enable is continuing to construct additional crude oil gathering capacity in this area. Enable's natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

As of December 31, 2013, Enable's portfolio of energy infrastructure assets included approximately 11,000 miles of gathering pipelines, 12 major processing plants with approximately 2.1 Bcf/d of processing capacity, approximately 7,900 miles of interstate pipelines, approximately 2,300 miles of intrastate pipelines and eight storage facilities comprising 86.5 Bcf of storage capacity.

Enable's expansion capital expenditures are expected to be approximately $450 million for the twelve months ended March 31, 2015.

For the year ended December 31, 2013, on a pro forma basis, approximately 76% of Enable's gross margin was generated from contracts that are fee-based, and approximately 50% of its gross margin was attributable to firm contracts or contracts with minimum volume commitment features.

Enable provides gathering, processing, treating, compression, dehydration and NGL fractionation for natural gas producers. Enable's gathering and processing assets are strategically located in established and actively developing basins in the United States and are interconnected with their interstate and intrastate pipelines and with third-party pipelines, which provides customers with the benefits of a flexible and efficient transportation and storage system.

The following table sets forth certain information regarding Enable's gathering and processing assets on a pro forma basis as of December 31, 2013:

Asset/Basin	Length (miles)	Compression (Horsepower)	Average Gathering Volume (TBtu/d)	Number of Processing Plants	Processing Capacity (MMcf/d)	NGLs Produced (Bbl/d)	Gross Acreage Dedications (in millions)
Anadarko Basin	6,729	477,462	1.3	9	1,445	43,233	4.7
Arkoma Basin	2,676	137,928	1.0	1	60	4,686	1.2
Ark-La-Tex Basin(1)	1,639	182,892	1.3	2	545	10,814	0.7
Total	11,044	798,282	3.6	12	2,050	58,733	6.6

(1) Ark-La-Tex basin assets also include 14,500 Bbl/d of fractionation capacity and 6,300 Bbl/d of ethane pipeline capacity, which are not listed in the table.

Six processing plants in the Anadarko basin are interconnected via their large-diameter, rich gas gathering system in western Oklahoma, which spans 18 counties and has approximately 1.2 Bcf/d of processing capacity. 4.7 million gross acres of acreage dedications in the Anadarko basin area are served by this system, referred to as their "super-header" system. This system is configured to optimize the flow of natural gas and the utilization of the processing plants connected to it, which provides strategic growth opportunities. Enable has made investments to expand the super-header system, including its newest plant located in Custer Country, Oklahoma (the McClure Plant) that was placed in service in December 2013. The McClure Plant increased Enable's natural gas processing capacity in the basin by over 15%, providing an additional 200 MMCf/d of natural gas processing capacity. Enable expects to continue to grow the capacity of the super-header system through the planned addition of another new cryogenic processing plant and related gathering pipelines. This plant, which will be located in Grady County, Oklahoma (the Bradley Plant), will provide an additional 200 MMcf/d of processing capacity and is expected to be completed in the first quarter of 2015.

For the years ended December 31, 2013 and 2012, on a pro forma basis, Enable generated 61% and 56%, respectively, of its gathering and processing gross margin under long-term, fee-based agreements, and of this fee-based margin, approximately 38% and 40%, respectively, was attributable to gathering and processing contracts containing minimum volume commitment features. Under Enable's minimum volume commitment contracts, customers commit to ship a minimum annual volume of natural gas on its gathering system, or, in lieu of shipping such volumes, to pay periodically as if that minimum amount had been shipped. As of December 31, 2013, Enable had minimum volume commitments in lean natural gas developments of 1.6 Bcf/d with a weighted average remaining term of over nine years. Enable also has an emerging crude oil gathering business in the Bakken shale formation with a similar minimum volume commitment contract structure that it believes will provide an additional source of stable cash flows. Under Enable's acreage dedication contracts, its customers are generally required to deliver all of their production within the dedicated area to Enable's gathering system for processing over the period of the contract. As of December 31, 2013, Enable had acreage dedications in rich natural gas developments covering more than 5.7 million acres that generally have long lived reserves with a weighted average remaining term of approximately nine years. As of December 31, 2013, Enable's gathering and processing contracts for its top ten natural gas producer customers, which accounted for approximately 75% of its gathered volumes for the year ended December 31, 2013, on a pro forma basis, had a volume-weighted average remaining term of approximately nine years.

Enable's natural gas transportation and storage operations consist of interstate pipelines, intrastate pipelines and storage assets. Enable provides pipeline takeaway capacity for natural gas producers from supply basins to market hubs and critical natural gas supply for industrial end users and utilities, such as LDCs and power generators. Enable's interstate pipeline system includes approximately 7,900 miles of transportation pipelines and extends from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois. Enable' eight storage facilities in Oklahoma, Louisiana and Illinois have 86.5 Bcf of storage capacity and strategically complement its pipeline systems.

The following table sets forth certain information regarding Enable's transportation and storage assets as of December 31, 2013:

Asset	Length (miles)	Capacity	Total Firm Contracted Capacity (Bcf/d)	Average Throughput Volume (Tbtu/d)	Percent of Capacity under Firm Contracts	Weighted Average Remaining Firm Contract Life (years)
Interstate Transportation[1]	7,880	8.4 BCF/d	8	3.5 [2]	95%	3.9
Intrastate Transportation	2,304	1.9 BCF/d[3]	—	1.6	—%	4.9
Storage	—	86.5 BCF	67.9	—	79%	4.4

(1) Except with respect to length, this information does not include amounts for Southeast Supply Header, LLC. Southeast Supply Header, LLC is a non-consolidated entity in which Enable own a 24.95% ownership interest.

(2) Actual volumes transported per day may be less than total firm contracted capacity based on demand.

(3) This represents the maximum single day receipts on the intrastate systems. Enable's Oklahoma intrastate pipeline system is a web-like configuration with multidirectional flow capabilities between numerous receipt and delivery points, which limits the ability to determine an overall system capacity. During the year ended December 31, 2013, the peak daily throughput was 1.9 TBtu or, on a volumetric basis, 1.9 Bcf/d.

Enable generates revenue primarily by charging demand fees pursuant to applicable tariffs for the transportation and storage of natural gas on its system. On a pro forma basis, Enable generated 96% of its transportation and storage gross margin is generated under fee-based agreements with a weighted average remaining contract life of over four years as of December 31, 2013. Demand-based margin for this period represented 89% of the fee-based margin, on a pro forma basis. Enable generally does not take ownership of the natural gas it transports and stores.

ENVIRONMENTAL MATTERS

General

The activities of the Company are subject to stringent and complex Federal, state and local laws and regulations governing environmental protection relating to air quality, water quality, waste management, wildlife conservation and natural resources. These laws and regulations can restrict or impact business activities in many ways, such as restricting the way it can handle or dispose of its wastes, requiring remedial action to mitigate environmental issues that may be caused by its operations or that are attributable to former operators, requiring changes in operations and requiring the installation and operation of pollution control equipment. Failure to comply with these laws and regulations could result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations.

The trend in environmental regulation, however, is to place more restrictions and limitations on activities that may affect the environment. The Company 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 it 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 total expenditures to comply with environmental laws, regulations and requirements for 2014 will be $72.6 million of which $55.0 million is for capital expenditures. It is estimated that OG&E's total expenditures to comply with environmental laws, regulations and requirements for 2015 will be $49.6 million of which $31.3 million is for capital expenditures. The amounts for OG&E above include capital expenditures for low NOX burners and activated carbon injection and exclude certain other capital expenditures as discussed in footnote D to the capital expenditures table 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. Other working capital requirements are expected to be primarily related to maturing debt, operating lease obligations, fuel clause under and over recoveries and other general corporate purposes. The Company generally meets its cash needs through a combination of cash generated from operations, short-term borrowings (through a combination of bank borrowings and commercial paper) and permanent financings. 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 2014 through 2018 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. The Company believes that Enable has, or will have, access to adequate liquidity and, therefore, no contributions are expected to be necessary to fund the capital expenditures of Enable from the general partners. Accordingly, capital expenditures for Enable are not included in the table below.

(In millions)	2014	2015	2016	2017	2018
OG&E Base Transmission	$ 30	$ 30	$ 30	$ 30	$ 30
OG&E Base Distribution	175	175	175	175	175
OG&E Base Generation	140	75	75	75	75
OG&E Other	15	15	15	15	15
Total OG&E Base Transmission, Distribution, Generation and Other	360	295	295	295	295
OG&E Known and Committed Projects:					
Transmission Projects:					
Regionally Allocated Base Projects (A)	55	20	20	20	20
Balanced Portfolio 3E Projects (B)(C)	15	—	—	—	—
SPP Priority Projects (B)(C)	75	—	—	—	—
SPP Integrated Transmission Projects (B) (C)	15	25	30	25	10
Total Transmission Projects	160	45	50	45	30
Other Projects:					
Smart Grid Program	25	10	10	—	—
Environmental - low NOX burners	35	20	15	10	—
Environmental - activated carbon injection	5	10	5	—	—
Total Other Projects	65	40	30	10	—
Total OG&E Known and Committed Projects	225	85	80	55	30
Total OG&E (D)	585	380	375	350	325
OGE Energy	15	10	10	10	10
Total capital expenditures	$ 600	$ 390	$ 385	$ 360	$ 335

(A) Approximately 30% of revenue requirement allocated to SPP members other than OG&E.
(B) Approximately 85% of revenue requirement allocated to SPP members other than OG&E.

(C)

Project Type	Project Description	Estimated Cost (In millions)	Projected In-Service Date
Balance Portfolio 3E	96 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to the Oklahoma /Texas Stateline to a companion transmission line to its Tuco substation	$110	Mid-2014
Priority Project	99 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to the western Beaver County line to a companion transmission line to its Hitchland substation	$165	Mid-2014
Priority Project	77 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to a companion transmission line at the Kansas border	$140	Late 2014
Integrated Transmission Project	47 miles of transmission line from OG&E's Gracemont substation to an AEP companion transmission line to its Elk City substation	$45	Early 2018
Integrated Transmission Project	126 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to OG&E's Cimarron substation; construction of the Mathewson substation on this transmission line	$180	Early 2021

(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. On July 19, 2013, the U.S. Court of Appeals for the Tenth Circuit by a 2 to 1 vote denied the petition for review and affirmed the EPA's issuance of the FIP. On January 2, 2014, the Tenth Circuit confirmed that the stay of the FIP has remained in place and continues until the Tenth Circuit issues the mandate. A Petition for Certiorari was filed by the State of Oklahoma, the Industrial Consumers and OG&E with the United States Supreme Court on January 29, 2014. The mandate from the Tenth Circuit has been stayed until the Supreme Court acts on the petition. If the Supreme Court elects not to hear the case, OG&E will have approximately 55 months from the effective date of the lifting of the stay to achieve compliance with the FIP.
- Installation of control equipment (other than activated carbon injection) for compliance with MATS by a deadline of April 16, 2016, which includes a one-year extension which was granted by the Oklahoma Department of Environmental Quality. As noted above, OG&E is currently planning to utilize activated carbon injection for the removal of mercury at each of its five coal-fired units, the capital costs of which are estimated to be approximately $20 million over a three year period and are included in the capital expenditures table in "Future Capital Requirements and Financing Activities" above. OG&E continues to review whether additional controls such as dry sorbent injection are needed for compliance with MATS. Current capital costs for installing the necessary control equipment for dry sorbent injection are estimated to be approximately $45 million over a three year period, but due to the uncertainty as to whether or not dry sorbent injection is necessary, such costs are not included in the capital expenditures table in "Future Capital Requirements and Financing Activities" above.

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.

Additional capital expenditures beyond those identified in the table above, including additional incremental growth opportunities in electric transmission assets will be evaluated based upon their impact upon achieving the Company's financial objectives.

Pension and Postretirement Benefit Plans

During both 2013 and 2012, OGE Energy made contributions to its Pension Plan of $35 million to help ensure that the Pension Plan maintains an adequate funded status. During 2014, OGE Energy expects to contribute up to $26 million to its Pension Plan. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Liquidity and Capital Resources - Future Capital Requirements and Financing Activities" for a discussion of OGE Energy's pension and postretirement benefit plans.

Common Stock Dividends

At the Company's December 2013 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 $0.22500 per share from $0.20875 per share effective with the Company's first quarter 2014 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, proceeds from the sales of common stock to the public through the Company's Automatic Dividend Reinvestment and Stock Purchase Plan or other offerings and distributions from Enable will be adequate over the next three years to meet anticipated cash needs and to fund future growth opportunities. 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 Company has revolving credit facilities totaling in the aggregate $1,150.0 million. These bank facilities can also be used as letter of credit facilities. The short-term debt balance was $439.6 million and $430.9 million at December 31, 2013 and 2012, respectively. The weighted-average interest rate on short-term debt at December 31, 2013 was 0.30 percent. The average balance of short-term debt in 2013 was $485.0 million at a weighted-average interest rate of 0.34 percent. The maximum month-end balance of short-term debt in 2013 was $663.9 million. At December 31, 2013, the Company had $715.1 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, 2013, the Company had $6.8 million in cash and cash equivalents. See Note 12 of Notes to Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

Effective May 1, 2013, Enable entered into a $1.4 billion, five-year senior unsecured revolving credit facility in accordance with the terms of the Master Formation Agreement and Enogex LLC's $400.0 million revolving credit facility was terminated.

In December 2011, the Company and OG&E entered into unsecured five-year revolving credit agreements to total in the aggregate $1,150.0 million ($750.0 million for the Company and $400.0 million for OG&E). Each of the credit facilities contain an option, which may be exercised up to two times, to extend the term for an additional year, subject to consent of a specified percentage of the lenders. Effective July 29, 2013, the Company and OG&E utilized one of these one-year extensions, and received consent from all of the lenders, to extend the maturity of their credit agreements to December 13, 2017.

Issuance of Long-Term Debt

On May 8, 2013, OG&E issued $250 million of 3.9% senior notes due May 1, 2043. The proceeds from the issuance were added to OG&E's general funds and were used to repay short-term debt, to fund capital expenditures, to pay general corporate expenses and for working capital purposes.

Expected Issuance of Long-Term Debt

OG&E expects to issue up to $250 million of long-term debt during 2014, depending on market conditions, to fund capital expenditures, to repay short or long-term borrowings and for general corporate purposes.

Common Stock

The Company expects to issue between $10 million and $15 million of common stock in its Automatic Dividend Reinvestment and Stock Purchase Plan in 2014. See Note 10 of Notes to Consolidated Financial Statements for a discussion of the Company's common stock activity.

Distributions by Enable

Pursuant to the Enable limited partnership agreement, during 2013 Enable made distributions of approximately $51.7 million, to the Company.

EMPLOYEES

The Company had 3,269 employees at December 31, 2013. Included in this total are 780 employees that are seconded to Enable.

EXECUTIVE OFFICERS

The following persons were Executive Officers of the Registrant as of February 25, 2014:

Name	Age	Title
Peter B. Delaney	60	Chairman of the Board, President and Chief Executive Officer - OGE Energy Corp.
Sean Trauschke	46	Chief Financial Officer - OGE Energy Corp.
William J. Bullard	65	Assistant General Counsel - OGE Energy Corp.
Scott Forbes	56	Controller and Chief Accounting Officer - OGE Energy Corp.
Patricia D. Horn	55	Vice President - Governance and Corporate Secretary - OGE Energy Corp.
Gary D. Huneryager	63	Vice President - Internal Audits - OGE Energy Corp.
Jesse B. Langston	51	Vice President - Retail Energy - OG&E
Jean C. Leger, Jr.	55	Vice President - Utility Operations - OG&E
Cristina F. McQuistion	49	Vice President - Strategic Planning, Performance Improvement and Chief Information Officer - OG&E
Jerry A. Peace	51	Chief Generation Planning and Procurement Officer - OG&E
Paul L. Renfrow	57	Vice President - Public Affairs, HR, HS&E and Regulatory - OGE Energy Corp.
Charles B. Walworth	39	Treasurer - OGE Energy Corp.

No family relationship exists between any of the Executive Officers of the Registrant. Messrs. Delaney, Trauschke, Bullard, Forbes, Huneryager, Renfrow, Walworth and Ms. Horn are also officers of OG&E. Each Executive Officer is to hold office until the Board of Directors meeting following the next Annual Meeting of Shareowners, currently scheduled for May 15, 2014.

As a result of the formation of Enable on May 1, 2013, Messrs. Delaney and Trauschke became members of the Board of Directors of Enable GP, LLC, the general partner of Enable.

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.
	2013 - Present:	Director of Enable GP LLC
	2013 - Present:	Chairman of the Board and Chief Executive Officer of OG&E
	2012 - 2013:	Chairman of the Board, President and Chief Executive Officer of OG&E
	2010 - 2011:	Chairman of the Board and Chief Executive Officer of OGE Energy Corp. and OG&E
	2010 - 2013:	Chief Executive Officer of Enogex Holdings
	2009 - 2013:	Chief Executive Officer of Enogex LLC
	2009 - 2010:	Chairman of the Board, President and Chief Executive Officer of OGE Energy Corp. and OG&E
Sean Trauschke	2014 - Present:	Chief Financial Officer of OGE Energy Corp.
	2013 - Present:	Director of Enable GP LLC
	2013 - Present:	President and Chief Financial Officer of OG&E
	2013 - 2014:	Vice President and Chief Financial Officer of OGE Energy Corp.
	2013:	Acting Chief Financial Officer of Enable GP LLC
	2009 - 2013:	Vice President and Chief Financial Officer of OGE Energy Corp. and OG&E
	2010 - 2013:	Chief Financial Officer of Enogex Holdings
	2009 - 2013:	Chief Financial Officer of Enogex LLC
	2009:	Senior Vice President - Investor Relations and Financial Planning of Duke Energy (electric utility)
William J. Bullard	2010 - Present:	Assistant General Counsel of OGE Energy Corp.; General Counsel of OG&E
	2009 - 2010:	Assistant General Counsel of OGE Energy Corp. and OG&E
Scott Forbes	2009 - Present:	Controller and Chief Accounting Officer of OGE Energy Corp. and OG&E
	2009:	Interim Chief Financial Officer of OGE Energy Corp. and OG&E

Patricia D. Horn	2014 - Present:	Vice President - Governance and Corporate Secretary of OGE Energy Corp. and OG&E
	2012 - 2014:	Vice President - Governance, Environmental and Corporate Secretary of OGE Energy Corp. and OG&E
	2010 - 2013:	Secretary of Enogex Holdings and Corporate Secretary of Enogex LLC
	2010 - 2012:	Vice President - Governance, Environmental, Health & Safety; Corporate Secretary of OGE Energy Corp. and OG&E
	2009 - 2010:	Vice President - Legal, Regulatory, Environmental Health & Safety and General Counsel of Enogex LLC
	2009 - 2010:	Assistant General Counsel of OGE Energy Corp.
Gary D. Huneryager	2009 - Present:	Vice President - Internal Audits of OGE Energy Corp. and OG&E
Jesse B. Langston	2009 - Present:	Vice President - Retail Energy of OG&E
Jean C. Leger, Jr.	2009 - Present:	Vice President - Utility Operations of OG&E
Cristina F. McQuistion	2014 - Present:	Vice President - Strategic Planning, Performance Improvement and Chief Information Officer of OG&E
	2013 - 2014:	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
	2009 - 2011:	Vice President - Process and Performance Improvement of OGE Energy Corp. and OG&E
Jerry A. Peace	2014 - Present:	Chief Generation Planning and Procurement Officer of OG&E
	2009 - 2014:	Chief Risk Officer of OGE Energy Corp. and OG&E
Paul L. Renfrow	2014 - Present:	Vice President - Public Affairs, HR, HS&E and Regulatory of OGE Energy Corp.
	2012 - 2014:	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
	2009 - 2011:	Vice President - Public Affairs of OGE Energy Corp. and OG&E
Charles B. Walworth	2014 - Present:	Treasurer of OGE Energy Corp. and OG&E
	2012 - 2014:	Assistant Treasurer of OGE Energy Corp. and OG&E
	2010 - 2012:	Senior Manager Finance of OGE Energy Corp.
	2009 - 2010:	Manager Corporate Finance of OGE Energy Corp.

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 $80 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. Although the court initially stayed implementation of EPA's FIP, it ultimately issued a decision affirming the FIP, and unless the Supreme Court accepts an appeal of the case, the FIP will require installation of Dry Scrubbers or fuel switching with a deadline sometime in 2018 or 2019.

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. The EPA has started a process to implement carbon dioxide emission limitations for existing electric generating units, and neither the outcome of the rule making process nor the timing of any required expenditures resulting from the EPA rule making process can be predicted with any certainty at this time.

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 that can restrict or impact OG&E'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 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 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 Sales 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.

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 assets, including our investment in unconsolidated affiliates, 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 operates 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) which may result in a loss of service to customers and also subject OG&E 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.

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.

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, 2013, 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 industry. The median age of utility workers is significantly higher than the national average. Over the next three years, 35 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 subsidiary and equity investments.

We are a holding company and thus our investments in our subsidiary and unconsolidated affiliate, accounted for under the equity method, are our primary assets. Substantially all of our operations are conducted by our subsidiary and unconsolidated affiliate. Consequently, our operating cash flow and our ability to pay our dividends and service our indebtedness depends upon the operating cash flow of our subsidiary and unconsolidated affiliate and the payment of funds by them to us in the form of dividends or distributions. At December 31, 2013, the Company and its subsidiary had outstanding indebtedness and other liabilities of $6.1 billion. Our subsidiary and unconsolidated affiliate 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, their 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 subsidiary or unconsolidated affiliate on their respective assets will generally have priority over our claims (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 OG&E 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 OG&E are in compliance with the financial covenants set forth in our revolving credit agreements and the indentures governing our debt securities, we and OG&E may be able to incur substantial additional indebtedness. If we or OG&E 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.

RISKS ASSOCIATED WITH OUR INVESTMENT IN ENABLE MIDSTREAM PARTNERS

Effective May 1, 2013, OGE Energy does not control Enogex Holdings LLC or Enable, and therefore is not able to cause or prevent certain actions by Enable.

Enable has its own governing board, and OGE Energy will not control all of the decisions of that board. Consequently, OGE Energy will be unable solely to cause Enable to take actions that OGE Energy believes would be in our or Enable' best interests. Likewise, OGE Energy will be unable to prevent certain actions of Enable.

A significant portion of our earnings and operating cash flows depend on the performance of Enable. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected.

Our operating cash flow is derived partially from cash distributions we receive from Enable.

Our operating cash flow is derived partially from cash distributions we receive from Enable. The amount of cash it can distribute principally depends upon the amount of cash flow it generates from its operations, which may fluctuate from quarter to quarter based on, among other things.

- the fees and gross margins realized with respect to the volume of natural gas and crude oil handled;
- the prices of, levels of production of, and demand for natural gas and crude oil;
- the volume of natural gas and crude oil gathered, compressed, treated, dehydrated, processed, fractionated, transported and stored;
- the relationship among prices for natural gas, NGLs and crude oil;
- cash calls and settlements of hedging positions;
- margin requirements on open price risk management assets and liabilities;
- the level of competition from other midstream energy companies;
- adverse effects of governmental and environmental regulation;
- the level of operation and maintenance expenses and general and administrative costs; and
- prevailing economic conditions.

In addition, the actual amount of cash available for distribution will depend on other factors, including:

- the level and timing of capital expenditures;
- the cost of acquisitions;
- debt service requirements and other liabilities;
- fluctuations in working capital needs;
- ability to borrow funds and access capital markets;
- restrictions contained in debt agreements;
- other business risks affecting its cash levels.

Enable may not be able to successfully integrate the operations of OGE Holdings and CenterPoint.

Pursuant to the Master Formation Agreement, OGE Energy and the ArcLight group indirectly contributed 100 percent of the equity interests in Enogex LLC to Enable. CenterPoint Energy Field Services, LLC was converted into a Delaware limited partnership that became Enable Midstream Partners, LP. CenterPoint contributed to Enable its equity interests in each of (i) CenterPoint Energy Gas Transmission Company, LLC, (ii) MRT, and (iii) certain of its other midstream subsidiaries and caused its subsidiary CenterPoint Energy Southeastern Pipelines Holding, LLC to contribute a 24.95 percent interest in Southeast Supply Header, LLC. If Enable is not able to successfully integrate these operations, it could have an adverse impact on our financial position, results of operations or cash flows.

Enable's contracts are subject to renewal risk

Enable generates a substantial portion of its gross margins under long-term, fee-based agreements. For the year ended December 31, 2013, on a pro forma basis, approximately 76% of its gross margin was generated from contracts that are fee-based and approximately 50% of its gross margin was attributable to firm contracts or contracts with minimum volume commitment features. As these and other contracts expire, extensions or renewals with existing suppliers and customers may have to be renegotiated or new contracts with other suppliers and customers may be necessary. Enable may be unable to obtain new contracts on favorable commercial terms, if at all, and also may be unable to maintain the economic structure of a particular contract with an existing customer or the overall mix of its contract portfolio. For example, depending on prevailing market conditions at the time of a contract renewal, gathering and processing customers with fixed-fee or fixed-margin contracts may desire to enter into contracts under different fee arrangements. To the extent Enable is unable to renew its existing contracts on favorable terms, if at all, or successfully manage its overall contract mix over time, its revenue, results of operations and distributable cash flow could be adversely affected.

Enable depends on a small number of customers for a significant portion of its firm transportation and storage services revenues. The loss of, or reduction in volumes from, these customers could result in a decline in sales of its transportation and storage services and its consolidated financial position, results of operations and its ability to make cash distributions to us.

Enable provides firm transportation and storage services to certain key customers on its system. Enable's major transportation customers are affiliates of CenterPoint Energy, Laclede Group, Exxon Mobile Corporation, OGE Energy and American Electric Power Company, Inc. Enable's interstate transportation and storage assets were designed and built to serve affiliates of CenterPoint Energy, Laclede Group, OGE Energy and American Electric Power Company.

The loss of all or even a portion of the interstate or intrastate transportation and storage services for any 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 adversely affect Enable's ability to make cash distributions to OGE Energy.

The businesses of Enable are dependent, in part, on the drilling and production decisions of others.

The businesses of Enable are dependent on the continued availability of natural gas and crude oil production. Enable has no control over the level of drilling activity in its areas of operation, the amount of reserves associated with wells connected to its systems or the rate at which production from a well declines. In addition, its cash flows associated with wells currently connected to its systems will 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, its customers must continually obtain new natural gas and crude oil supplies. The primary factors affecting its ability to obtain new supplies of natural gas and crude oil and attract new customers to its assets are the level of successful drilling activity near these systems, its ability to compete for volumes from successful new wells and its ability to expand capacity as needed. If Enable is not able to obtain new supplies of natural gas and crude oil 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 results of operations and distributable cash flow. Enable has no control over producers or its drilling and production decisions, which are affected by, among other things:

- the availability and cost of capital;
- prevailing and projected commodity prices, including the prices of natural gas, NGLs and crude oil;
- demand for natural gas, NGLs and crude oil;

- levels of reserves;
- geological considerations;
- environmental or other governmental regulations, including the availability of drilling permits and the regulation of hydraulic fracturing; and
- the availability of drilling rigs and other costs of production and equipment.

Fluctuations in energy prices can also greatly affect the development of new natural gas and crude oil reserves. Drilling and production activity generally decreases as commodity prices decrease. In general terms, the prices of natural gas, crude oil and other hydrocarbon products fluctuate in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond its control. Because of these factors, even if new natural gas or crude oil reserves are known to exist in areas served by its assets, producers may choose not to develop those reserves. Declines in natural gas or crude oil prices can have a negative impact on exploration, development and production activity and, if sustained, could lead to decreases in such activity. A sustained decline could also lead producers to shut in production from its existing wells. Sustained reductions in exploration or production activity in its areas of operation could lead to further reductions in the utilization of its systems, which could have a material adverse effect on its business, financial condition, results of operations and ability to make quarterly cash distributions to its unitholders, including us.

In addition, it may be more difficult to maintain or increase the current volumes on its gathering systems, as several of the formations in the unconventional resource plays in which Enable operates generally has higher initial production rates and steeper production decline curves than wells in more conventional basins. Should Enable determine that the economics of its gathering assets do not justify the capital expenditures needed to grow or maintain volumes associated therewith, it may reduce such capital expenditures, which could cause revenues associated with these assets to decline over time. In addition to capital expenditures to support growth, the steeper production decline curves associated with unconventional resource plays may require Enable to incur higher maintenance capital expenditures relative to throughput over time, which will reduce its distributable cash flow.

Because of these and other factors, even if new reserves are known to exist in areas served by its assets, producers may choose not to develop those reserves. Reductions in drilling activity would result in an inability to maintain the current levels of throughput on its systems and could have a material adverse effect on its results of operations and distributable cash flow.

Enable's industry is highly competitive, and increased competitive pressure could adversely affect its results of operations and distributable cash flow.

Enable competes with similar enterprises in its respective areas of operation. The principal elements of competition are rates, terms of service and flexibility and reliability of service. Competitors include large crude oil, natural gas and petrochemical companies that have greater financial resources and access to supplies of natural gas, NGLs and crude oil. Some of these competitors may expand or construct gathering, processing, transportation and storage systems that would create additional competition for the services Enable provides to its customers. Excess pipeline capacity in the regions served by our interstate pipelines could also increase competition and adversely impact the ability to renew or enter into new contracts with respect to available capacity when existing contracts expire. In addition, customers that are significant producers of natural gas may develop their own gathering, processing, transportation and storage systems. Enable's ability to renew or replace existing contracts with customers at rates sufficient to maintain current revenues and cash flows could be adversely affected by the activities of its competitors and customers. Further, natural gas utilized as a fuel competes with other forms of energy available to end-users, including electricity, coal and liquid fuels. Increased demand for such forms of energy at the expense of natural gas could lead to a reduction in demand for natural gas gathering, processing, transportation and transportation services. All of these competitive pressures could adversely affect its results of operations and distributable cash flow.

Enable derives a substantial portion of its operating income and cash flow from subsidiaries through which it holds a substantial portion of its assets.

Enable derives a substantial portion of its operating income and cash flow from, and holds a substantial portion of its assets through, its subsidiaries. As a result, it depends on distributions from its subsidiaries in order to meet its payment obligations. In general, these subsidiaries are separate and distinct legal entities and have no obligation to provide Enable with funds for its payment obligations, whether by dividends, distributions, loans or otherwise. In addition, provisions of applicable law, such as those limiting the legal sources of dividends, limit its subsidiaries' ability to make payments or other distributions, and its subsidiaries could agree to contractual restrictions on its ability to make distributions.

The right by Enable to receive any assets of any subsidiary, and therefore the right of its creditors to participate in those assets, will be effectively subordinated to the claims of that subsidiary's creditors, including trade creditors. In addition, even if Enable were a creditor of any subsidiary, its rights as a creditor would be subordinated to any security interest in the assets of that subsidiary and any indebtedness of the subsidiary senior to that held by them.

Enable may not be able to recover the costs of its substantial planned investment in capital improvements and additions, and the actual cost of such improvements and additions may be significantly higher than it anticipates.

Enable's business plan calls for extensive investment in capital improvements and additions. Capital expenditures are expected to be $450 million for the twelve months ending March 31, 2015. For example, Enable is currently constructing a cryogenic processing plant in Grady County, Oklahoma (the Bradley Plant), which will provide an additional 200 MMcf/d of processing capacity and is expected to be completed in the first quarter of 2015. In addition, other assets are expected to be placed in service in 2014 related to its crude oil gathering pipeline system in North Dakota's Bakken shale formation.

The construction of additions or modifications to Enable's existing systems, and the construction of new midstream assets, involves numerous regulatory, environmental, political and legal uncertainties, many of which are beyond its control and may require the expenditure of significant amounts of capital, which may exceed estimates. These projects may not be completed at the planned cost, on schedule or at all. The construction of new pipeline, gathering, treating, processing, compression or other facilities is subject to construction cost overruns due to labor costs, costs of equipment and materials such as steel, labor shortages or weather or other delays, inflation or other factors, which could be material. In addition, the construction of these facilities is typically subject to the receipt of approvals and permits from various regulatory agencies. Those agencies may not approve the projects in a timely manner, if at all, or may impose restrictions or conditions on the projects that could potentially prevent a project from proceeding, lengthen its expected completion schedule and/or increase its anticipated cost. Moreover, revenues and cash flows may not increase immediately upon the expenditure of funds on a particular project. For instance, if an existing pipeline expanded or a new pipeline constructed, the construction may occur over an extended period of time, and material increases in revenues or cash flows may not be received until the project is completed. In addition Enable may construct facilities to capture anticipated future growth in production in a region in which such growth does not materialize. As a result, the new facilities may not be able to achieve an expected investment return, which could adversely affect its results of operations and ability to make cash distributions to its unitholders, including us.

In connection with its capital investments, Enable may engage a third party to estimate potential reserves in areas to be developed prior to constructing facilities in those areas. To the extent estimates of future production are relied on in deciding to construct additions to its systems, those estimates may prove to be inaccurate due to 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 its results of operations and ability to make cash distributions to unitholders. 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, preventing its ability 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, its results of operations and ability to make cash distributions to unitholders, including us, could be adversely affected.

Natural gas, NGL and crude oil prices are volatile, and changes in these prices could adversely affect Enable ability to make cash distributions.

Enable's ability to make cash distributions to us could be negatively affected by adverse movements in the prices of natural gas, NGLs and crude oil depending on factors that are beyond its 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, NGLs and crude oil, actions taken by foreign natural gas and oil 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.

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

Enable provides certain transportation and storage services under long-term, fixed-price "negotiated rate" contracts that are not subject to adjustment, even if the cost to perform such services exceeds the revenues received from such contracts, and, as a result, costs could exceed revenues received under such contracts.

Enable has been authorized by the FERC, to provide transportation and storage services at its facilities at negotiated rates. Generally, negotiated rates are in excess of the maximum recourse rates allowed by the FERC, but it is possible that costs to perform services under "negotiated rate" contracts will exceed the revenues obtained under these agreements. If this occurs, it could decrease the cash flow realized by its systems and, therefore, decrease the cash available for distribution to its unitholders, including us.

As of December 31, 2013, approximately 57% of Enable's contracted transportation firm capacity and 43% of its contracted storage firm capacity was subscribed under such "negotiated rate" contracts. These contracts generally do not include provisions allowing for adjustment for increased costs due to inflation, pipeline safety activities or other factors that are not tied to an applicable tracking mechanism authorized by the FERC. Successful recovery of any shortfall of revenue, representing the difference between "recourse rates" (if higher) and negotiated rates, is not assured under current FERC policies.

If third-party pipelines and other facilities interconnected to Enable's gathering, processing or transportation facilities become partially or fully unavailable, its ability to make cash distributions to us could be adversely affected.

Enable depends upon third-party natural gas pipelines to deliver natural gas to, and take natural gas from, its transportation systems. it also depends on third-party facilities to transport and fractionate NGLs that are delivered to the third party at the tailgates of the processing plants. Fractionation is the separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale. For example, an outage or disruption on certain pipelines or fractionators operated by a third party could result in the shutdown of certain of its processing plants, and a prolonged outage or disruption could ultimately result in a reduction in the volume of NGLs it is able to produce. Additionally, Enable depends on third parties to provide electricity for compression at many of its facilities. Since it does not own or operate any of these third-party pipelines or other facilities, continuing operation of those facilities is not within its control. If any of these third-party pipelines or other facilities become partially or fully unavailable to Enable for any reason, its results of operations and ability to make cash distributions to us could be adversely affected.

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

Enable 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. Enable may obtain the rights to construct and operate its pipelines on land owned by third parties and governmental agencies for a specific period of time. A loss of these rights, through its inability to renew right-of-way contracts or otherwise, could cause a cease in operations temporarily or permanently on the affected land, increase costs related to the construction and continuing operations elsewhere, and adversely affect its results of operations and ability to make cash distributions to unitholders, including us.

Enable conducts a portion of its operations through joint ventures, which subjects them to additional risks that could have a material adverse effect on the success of its operations, financial position and results of operations.

Enable conducts a portion of its operations through joint ventures with third parties, including Spectra Energy, DCP Midstream Partners, LP, Trans Louisiana Gas Pipeline, Inc. and Pablo Gathering LLC. It may also enter into other joint venture arrangements in the future. These third parties may have obligations that are important to the success of the joint venture, such as the obligation to pay their share of capital and other costs of the joint venture. The performance of these third-party obligations, including the ability of the third parties to satisfy their obligations under these arrangements, is outside the control of Enable.

The joint venture arrangements of Enable may involve risks not otherwise present when operating assets directly, including, for example:

- joint venture partners may share certain approval rights over major decisions;

- joint venture partners may not pay their share of the joint venture’s obligations, leaving Enable liable for their shares of joint venture liabilities;

- it may be unable to control the amount of cash it will receive from the joint venture;

- it may incur liabilities as a result of an action taken by its joint venture partners;

- it may be required to devote significant management time to the requirements of and matters relating to the joint ventures;

- its insurance policies may not fully cover loss or damage incurred by both them and its joint venture partners in certain circumstances;

- its joint venture partners may be in a position to take actions contrary to its instructions or requests or contrary to its policies or objectives; and

- disputes between them and its joint venture partners may result in delays, litigation or operational impasses.

The risks described above or the failure to continue joint ventures or to resolve disagreements with joint venture partners could adversely affect Enable's ability to transact the business that is the subject of such joint venture, which would in turn negatively affect its financial condition and results of operations. The agreements under which certain joint ventures were formed may subject them to various risks, limit the actions it may take with respect to the assets subject to the joint venture and require them to grant rights to its joint venture partners that could limit its ability to benefit fully from future positive developments. Some joint ventures require Enable to make significant capital expenditures. If it does not timely meet its financial commitments or otherwise do not comply with its joint venture agreements, its rights to participate, exercise operator rights or otherwise influence or benefit from the joint venture may be adversely affected. Certain of its joint venture partners may have substantially greater financial resources than Enable has and it may not be able to secure the funding necessary to participate in operations its joint venture partners propose, thereby reducing its ability to benefit from the joint venture.

Enable business involves many hazards and operational risks, some of which may not be fully covered by insurance. Insufficient insurance coverage and increased insurance costs could adversely impact its ability to make cash distributions to us.

Enable' operations are subject to all of the risks and hazards inherent in the gathering, processing, transportation and storage of natural gas and crude oil, including:

- damage to pipelines and plants, related equipment and surrounding properties caused by hurricanes, tornadoes, floods, fires and other natural disasters, acts of terrorism and actions by third parties;

- inadvertent damage from construction, vehicles, farm and utility equipment;

- leaks of natural gas, crude oil and other hydrocarbons or losses of natural gas and crude oil as a result of the malfunction of equipment or facilities;

- ruptures, fires and explosions; and

- other hazards that could also result in personal injury and loss of life, pollution and suspension of operations.

These risks could result in substantial losses due to personal injury and/or loss of life, severe damage to and destruction of property, plant and equipment and pollution or other environmental damage. These risks may also result in curtailment or suspension of its operations. A natural disaster or other hazard affecting the areas in which it operates could have a material adverse effect on its operations. Enable is not fully insured against all risks inherent in its business. It does not have business interruption insurance coverage for all of its operations. Insurance coverage may not be available in the future at current costs or on commercially reasonable terms, and the insurance proceeds received for any loss of, or any damage to, any of its facilities may not be sufficient to restore the loss or damage without negative impact on its results of operations and ability to make cash distributions to its unitholders, including us.

Enable's ability to grow is dependent on its ability to access external financing sources.

Enable expects its operating subsidiaries will distribute all of their available cash to Enable and that it will distribute all of its available cash to its unitholders. As a result, Enable expects that it and its operating subsidiaries will rely primarily upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund acquisitions and expansion capital expenditures. As a result, to the extent Enable or its operating subsidiaries are unable to finance growth externally, its cash distribution policy will significantly impair its ability to grow. In addition, because it and its operating subsidiaries distribute all available cash, its growth may not be as fast as businesses that reinvest their available cash to expand ongoing operations.

To the extent Enable issues additional units in connection with any acquisitions or expansion capital expenditures, the payment of distributions on those additional units may increase the risk it will be unable to maintain or increase its per unit distribution level, which in turn may impact the cash available to distribute on each unit. There are no limitations in the partnership agreement on its ability to issue additional units, including units ranking senior to the common units. The incurrence of additional commercial borrowings or other debt by Enable or its operating subsidiaries to finance its growth strategy would result in increased interest expense, which in turn may negatively impact the available cash that its operating subsidiaries have to distribute to it, and thus that it has to distribute to its unitholders, including us.

If Enable does not make acquisitions or is unable to make acquisitions on economically acceptable terms, its future growth will be limited.

Enable's ability to grow depends, in part, on the ability to make acquisitions that result in an increase in its cash generated from operations per common unit. If it is unable to make these accretive acquisitions either because: (i) it is unable to identify attractive acquisition targets or it is unable to negotiate purchase contracts on acceptable terms, (ii) it is unable to obtain acquisition financing on economically acceptable terms, or (iii) it is outbid by competitors, then its future growth and ability to increase distributions will be limited.

Enable's merger and acquisition activities may not be successful or may result in completed acquisitions that do not perform as anticipated.

From time to time, Enable has made, and it intends to continue to make, acquisitions of businesses and assets. Such acquisitions involve substantial risks, including the following:

- acquired businesses or assets may not produce revenues, earnings or cash flow at anticipated levels;

- acquired businesses or assets could have environmental, permitting or other problems for which contractual protections prove inadequate;

- it may assume liabilities that were not disclosed to it, that exceed its estimates, or for which its rights to indemnification from the seller are limited;

- it may be unable to integrate acquired businesses successfully and realize anticipated economic, operational and other benefits in a timely manner, which could result in substantial costs and delays or other operational, technical or financial problems; and

- acquisitions, or the pursuit of acquisitions, could disrupt its ongoing businesses, distract management, divert resources and make it difficult to maintain its current business standards, controls and procedures.

Enable and its operating subsidiaries' debt levels may limit its flexibility in obtaining additional financing and in pursuing other business opportunities.

As of December 31, 2013, Enable had approximately $1.9 billion of long-term debt outstanding and $200 million of short-term debt outstanding, excluding the premiums on senior notes in addition to $363 million of long-term notes payable due to CenterPoint Energy. Enable also has a $1.4 billion revolving credit facility for working capital, capital expenditures and other partnership purposes, including acquisitions, of which $1.1 billion was available as of December 31, 2013. Following the planned IPO, it will continue to have the ability to incur additional debt, subject to limitations in its credit facilities. The levels of 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, if at all;

- a portion of cash flows will be required to make interest payments on the debt, reducing the funds that would otherwise be available for operations, future business opportunities and distributions;

- the debt level will make Enable more vulnerable to competitive pressures or a downturn in the business or the economy generally; and

- the debt level may limit flexibility in responding to changing business and economic conditions.

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

Enable’s credit facilities contain operating and financial restrictions, including covenants and restrictions that may be affected by events beyond its control, which could adversely affect its business, financial condition, results of operations and ability to make quarterly distributions to its unitholders.

- Enable's credit facilities contain customary covenants that, among other things, limit the ability to:

- permit its subsidiaries to incur or guarantee additional debt;

- incur or permit to exist certain liens on assets;

- dispose of assets;

- merge or consolidate with another company or engage in a change of control;

- enter into transactions with affiliates on non-arm’s length terms; and

- change the nature of its business.

Enable’s credit facilities also require it to maintain certain financial ratios. Its ability to meet those financial ratios can be affected by events beyond its control, and assurance it will meet those ratios cannot be guaranteed. In addition, its credit facilities contain events of default customary for agreements of this nature.

Enable's ability to comply with the covenants and restrictions contained in its credit facilities may be affected by events beyond its control, including prevailing economic, financial and industry conditions. If market or other economic conditions deteriorate, its ability to comply with these covenants may be impaired. If any of the restrictions, covenants, ratios or tests in its credit facilities is violated, a significant portion of its indebtedness may become immediately due and payable. In addition, its lenders’ commitments to make further loans under the revolving credit facility may be suspended or terminated. Enable might not have, or be able to obtain, sufficient funds to make these accelerated payments.

Enable may be unable to obtain or renew permits necessary for its operations, which could inhibit its ability to do business.

Performance of its operations require it obtain and maintain a number of federal and state permits, licenses and approvals with terms and conditions containing a significant number of prescriptive limits and performance standards in order to operate. All of these permits, licenses, approval limits and standards require a significant amount of monitoring, record keeping and reporting in order to demonstrate compliance with the underlying permit, license, approval limit or standard. Noncompliance or incomplete documentation of our compliance status may result in the imposition of fines, penalties and injunctive relief. A decision by a government agency to deny or delay the issuance of a new or existing material permit or other approval, or to revoke or substantially modify an existing permit or other approval, could adversely affect its ability to initiate or continue operations at the affected location or facility and on its financial condition, results of operations and cash flows.

Additionally, in order to obtain permits and renewals of permits and other approvals in the future, Enable may be required to prepare and present data to governmental authorities pertaining to the potential adverse impact that any proposed pipeline or processing-related activities may have on the environment, individually or in the aggregate, including on public and Indian lands. Certain approval procedures may require preparation of archaeological surveys, endangered species studies and other studies to assess the environmental impact of new sites or the expansion of existing sites. Compliance with these regulatory requirements is expensive and significantly lengthens the time required to prepare applications and to receive authorizations.

Costs of compliance with existing environmental laws and regulations are significant, and the cost of compliance with future environmental laws and regulations may adversely affect Enable's results of operations and its ability to make cash distributions to unitholders, including us.

Enable is 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, delay or increase costs of construction, restrict or limit the output of certain facilities and/or require additional pollution control equipment and otherwise increase costs. There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations and those costs may be even more significant in the future.

There is inherent risk of the incurrence of environmental costs and liabilities in its operations due to the handling of natural gas, NGLs and crude oil, air emissions related to its 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 and the protection of plants, wildlife, and natural and cultural resources. These laws and regulations can restrict or impact business activities in many ways, such as restricting the handling or disposing of wastes or requiring remedial action to mitigate pollution conditions that may be caused by its operations or that are attributable to former operators. Joint and several strict liability may be incurred, without regard to fault, under certain of these environmental laws and regulations in connection with discharges or releases of wastes on, under or from its properties and facilities, many of which have been used for midstream activities for a number of years, oftentimes by third parties not under its control. Private parties, including the owners of the properties through which its gathering systems pass and facilities where its wastes are taken for reclamation or disposal, may also have the right to pursue legal actions to enforce compliance, as well as to seek damages for non- compliance, with environmental laws and regulations or for personal injury or property damage. For example, an accidental release from one of its pipelines could subject them to substantial liabilities arising from environmental cleanup and restoration costs, claims made by neighboring landowners and other third parties for personal injury and property damage and fines or penalties for related violations of environmental laws or regulations. Enable 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. Further, stricter requirements could negatively impact its customers’ production and operations, resulting in less demand for its services.

Increased regulation of hydraulic fracturing could result in reductions or delays in natural gas production by Enable's customers, which could adversely affect its results of operations and ability to make cash distributions to its unitholders, including us.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. Many of its customers commonly use hydraulic fracturing techniques in their drilling and completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas commissions. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where its oil and natural gas exploration and production customers operate, such customers could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells, some or all of which activities could adversely affect demand for its services to those customers.

Enable may incur substantial liabilities to comply with climate change legislation and regulatory initiatives.

Because Enable's operations emit various types of greenhouse gases, legislation and regulations governing greenhouse gas emissions could increase its costs related to operating and maintaining its facilities, and could delay future permitting. Any additional costs or operating restrictions associated with new legislation or regulations regarding greenhouse gas emissions could have a material adverse effect on its operating results and cash flows, in addition to the demand for its services. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this view could negatively affect its ability to access capital markets or cause them to receive less favorable terms and conditions. Consequently, legislation and regulatory initiatives aimed at reducing greenhouse gases could have a material adverse effect on its results of operations and ability to make cash distributions to its unitholders, including us.

Enable's operations are subject to extensive regulation by federal regulatory authorities. Changes or additional regulatory measures adopted by such authorities could have a material adverse effect on its results of operations and ability to make cash distributions to its unitholders, including us.

The rates charged by several of Enable's pipeline systems, including for interstate gas transportation service provided by its intrastate pipelines, are regulated by the FERC. The FERC and state regulatory agencies also regulate other terms and conditions of the services it may offer. If one of these regulatory agencies, on its own initiative or due to challenges by third parties, were to lower its tariff rates or deny any rate increase or other material changes to the types, or terms and conditions, of service it might propose or offer, the profitability of its pipeline businesses could suffer. If it were permitted to raise its tariff rates for a particular pipeline, there might be significant delay between the time the tariff rate increase is approved and the time that the rate increase actually goes into effect, which could also limit profitability. Furthermore, competition from other pipeline systems may prevent them from raising its tariff rates even if permitted by regulatory agencies. The regulatory agencies that regulate its systems periodically implement new rules, regulations and terms and conditions of services subject to its jurisdiction. New initiatives or orders may adversely affect the rates charged for services or otherwise adversely affect its financial condition, results of operations and cash flows and ability to make cash distributions to its unitholders, including us.

Enable’s operations may also be subject to regulation by state and local regulatory authorities. Changes or additional regulatory measures adopted by such authorities could adversely affect its results of operations and its ability to make cash distributions to unitholders, including us.

The pipeline operations of Enable that are not regulated by the FERC may be subject to state and local regulation applicable to intrastate natural and transportation services. The relevant states in which it operates include North Dakota, Oklahoma, Arkansas, Louisiana, Texas, Missouri, Kansas, Mississippi, Tennessee and Illinois. State and local regulations generally focus on safety, environmental and, in some circumstances, prohibition of undue discrimination among shippers. Additional rules and legislation pertaining to these matters are considered and, in some instances, adopted from time to time. The effect, if any, such changes might have on operations cannot be predicted, but Enable 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 the business. Any such state or local regulation could have an adverse effect on the business and the results of operations.

Gathering lines may be subject to ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, oil or natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without undue discrimination as to source of supply or producer. These statutes restrict the right by Enable as an owner of gathering facilities to decide with whom it contracts to purchase or transport oil or natural gas. Federal law leaves economic regulation of natural gas gathering to the states. The states in which it operates have adopted complaint-based regulation of oil and natural gas gathering activities, which allows oil and natural gas producers and shippers to file complaints with state regulators in an effort to resolve grievances relating to access to oil and natural gas gathering pipelines and rate discrimination.

Other state regulations may not directly regulate the business, but may nonetheless affect the availability of natural gas for processing, including state regulation of production rates and maximum daily production allowable from gas wells. While its gathering lines are currently subject to limited state regulation, there is a risk that state laws will be changed, which may give producers a stronger basis to challenge the regulatory status of a line, or the rates, terms and conditions of a gathering line providing transportation service.

A change in the jurisdictional characterization of some of Enable’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.

Enable’s natural gas gathering and intrastate transportation operations are generally exempt from the jurisdiction of the FERC, but FERC regulation may indirectly impact these businesses and the markets for products derived from these businesses. The FERC’s policies and practices across the range of its oil and natural gas regulatory activities, including, for example, its policies on interstate open access transportation, ratemaking, capacity release, and market center promotion may indirectly affect intrastate markets. In recent years, the FERC has pursued pro-competitive policies in its regulation of interstate oil and natural gas pipelines. However, it cannot be assured that the FERC will continue to pursue this approach as it considers matters such as pipeline rates and rules and policies that may indirectly affect the intrastate natural gas transportation business. Although the FERC has not made a formal determination with respect to all of its facilities they consider to be gathering facilities, Enable believes that its natural gas gathering pipelines meet the traditional tests that the FERC has used to determine that a pipeline is a gathering pipeline and are therefore not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and the FERC determines whether facilities are gathering facilities on a case-by-case basis, so the classification and regulation of its gathering facilities is subject to change based on future determinations by the FERC, the courts or Congress. If the FERC were to consider the status of an individual facility and determine that the facility and/or services provided by it are not exempt from FERC regulation under the NGA and that the facility provides interstate service, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by the FERC under the NGA or the NGPA. Such regulation could decrease revenue, increase operating costs, and, depending upon the facility in question, could adversely affect Enable’s financial condition, results of operations and cash flows and our ability to make cash distributions to its unitholders. In addition, if any of its facilities were found to have provided services or otherwise operated in violation of FERC regulations, this could result in the imposition of substantial civil penalties, as well as a requirement to disgorge revenues collected for such services in excess of the maximum rates established by the FERC.

Natural gas gathering may receive greater regulatory scrutiny at the state level; therefore, Enable's natural gas gathering operations could be adversely affected should it become subject to the application of state regulation of rates and services. Enable’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. The effect, if any, such changes might have on its operations cannot be predicted, but additional capital expenditures could be required and increased costs could be incurred depending on future legislative and regulatory changes.

Enable may incur significant costs and liabilities resulting from pipeline integrity and other similar programs and related repairs.

The U.S. Department of Transportation has adopted regulations requiring pipeline operators to develop integrity management programs for transportation pipelines located in “high consequence areas,” which are those areas where a leak or rupture could do the most harm. The regulations require operators, including Enable, to, among other things:

- develop a baseline plan to prioritize the assessment of a covered pipeline segment;
- identify and characterize applicable threats that could impact a high consequence area;
- improve data collection, integration, and analysis;
- repair and remediate pipelines as necessary; and
- implement preventive and mitigating action.

Although many of Enable's pipelines fall within a class that is currently not subject to these requirements, significant cost and liabilities associated with repair, remediation, preventive or mitigation measures associated with its non-exempt pipelines could be incurred. This work is part of its normal integrity management program and it does not expect to incur any extraordinary costs during 2013 or 2014 to complete the testing required by existing Department of Transportation regulations and its state counterparts. Costs have not been estimated for any repair, remediation, preventive or mitigation actions that may be determined to be necessary as a result of the testing program, which could be substantial, or any lost cash flows resulting from the shutting down of pipelines during the pendency of such repairs. Should Enable fail to comply with Department of Transportation or comparable state regulations, it could be subject to penalties and fines. Also, the scope of the integrity management program and other related pipeline safety programs could be expanded in the future. The cost of complying with such future requirements has not been estimated.

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 6,785 MWs at December 31, 2013. 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	2013 Capacity Factor (A)	Unit Capability (MW)	Station Capability (MW)
Seminole	1	1971	Steam-Turbine	Gas	Base Load	20.2%	486	
	1GT	1971	Combustion-Turbine	Gas	Peaking	0.1% (B)	16	
	2	1973	Steam-Turbine	Gas	Base Load	26.1%	482	
	3	1975	Steam-Turbine	Gas/Oil	Base Load	24.1%	489	1,473
Muskogee	4	1977	Steam-Turbine	Coal	Base Load	39.3%	491	
	5	1978	Steam-Turbine	Coal	Base Load	51.0%	506	
	6	1984	Steam-Turbine	Coal	Base Load	59.3%	500	1,497
Sooner	1	1979	Steam-Turbine	Coal	Base Load	68.7%	520	
	2	1980	Steam-Turbine	Coal	Base Load	61.2%	521	1,041
Horseshoe Lake	6	1958	Steam-Turbine	Gas/Oil	Base Load	1.4%	169	
	7	1963	Combined Cycle	Gas/Oil	Base Load	17.1%	193	
	8	1969	Steam-Turbine	Gas	Base Load	10.1%	394	
	9	2000	Combustion-Turbine	Gas	Peaking	1.4% (B)	46	
	10	2000	Combustion-Turbine	Gas	Peaking	1.8% (B)	45	847
Redbud (C)	1	2003	Combined Cycle	Gas	Base Load	48.6%	149	
	2	2003	Combined Cycle	Gas	Base Load	41.9%	147	
	3	2003	Combined Cycle	Gas	Base Load	46.7%	147	
	4	2003	Combined Cycle	Gas	Base Load	50.3%	149	592
Mustang	1	1950	Steam-Turbine	Gas	Peaking	2.1% (B)	50	
	2	1951	Steam-Turbine	Gas	Peaking	2.2% (B)	50	
	3	1955	Steam-Turbine	Gas	Base Load	5.8%	121	
	4	1959	Steam-Turbine	Gas	Base Load	17.3%	242	
	5A	1971	Combustion-Turbine	Gas/Jet Fuel	Peaking	0.3% (B)	34	
	5B	1971	Combustion-Turbine	Gas/Jet Fuel	Peaking	0.4% (B)	36	533
McClain (D)	1	2001	Combined Cycle	Gas	Base Load	75.7%	353	353
Total Generating Capability (all stations, excluding wind stations) (E)								6,336

Station	Year Installed	Location	Number of Units	Fuel Capability	2013 Capacity Factor (A)	Unit Capability (MW)	Station Capability (MW)
Crossroads	2011	Canton, OK	98	Wind	44.3%	2.3	227.5
Centennial	2007	Laverne, OK	80	Wind	36.9%	1.5	120.0
OU Spirit	2009	Woodward, OK	44	Wind	40.6%	2.3	101.2
Total Generating Capability (wind stations)							448.7

(A) 2013 Capacity Factor = 2013 Net Actual Generation / (2013 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.

At December 31, 2013, OG&E's transmission system included: (i) 51 substations with a total capacity of 12.0 million kilovolt-amps and 4,589 structure miles of lines in Oklahoma and (ii) seven substations with a total capacity of 2.4 million kilovolt-amps and 278 structure miles of lines in Arkansas. OG&E's distribution system included: (i) 353 substations with a total capacity of 9.5 million kilovolt-amps, 29,144 structure miles of overhead lines, 2,239 miles of underground conduit and 10,617 miles of underground conductors in Oklahoma and (ii) 33 substations with a total capacity of 1.0 million kilovolt-amps, 2,775 structure miles of overhead lines, 232 miles of underground conduit and 696 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.

During the three years ended December 31, 2013, the Company's gross property, plant and equipment (excluding construction work in progress) additions were $2.3 billion and gross retirements were $249.0 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 24.9 percent of gross property, plant and equipment (excluding construction work in progress) at December 31, 2013.

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 15 and 16 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.

2014	Dividend Paid	Price High	Price Low
First Quarter (through February 20)	$ 0.2250	$ 36.25	$ 32.91
2013			
First Quarter	$ 0.2088	$ 35.08	$ 27.70
Second Quarter	0.2088	36.59	32.20
Third Quarter	0.2088	39.55	33.85
Fourth Quarter	0.2088	40.00	32.85
2012			
First Quarter	$ 0.1963	$ 28.77	$ 25.62
Second Quarter	0.1963	27.66	25.12
Third Quarter	0.1963	28.25	25.30
Fourth Quarter	0.1963	30.11	27.18

At the Company's December 2013 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 $0.2250 per share from $0.20875 per share effective with the Company's first quarter 2014 dividend.

The number of record holders of the Company's Common Stock at December 31, 2013, was 17,828. The book value of the Company's Common Stock at December 31, 2013 was $15.29.

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 and equity affiliates, the Company's cash flow and ability to pay dividends will be dependent on the earnings and cash flows of its subsidiaries and equity affiliates 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 Enable. 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 its limited partnership interest in Enable is subject to Enable's cash available for distribution, the terms of its limited partnership agreement, and the covenants of Enable's debt instruments limiting the ability of Enable 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 2013.

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
10/1/13 - 10/31/13	—		$ —	N/A	N/A
11/1/13 - 11/30/13	346	(A)	$ 34.68	N/A	N/A
12/1/13 - 12/31/13	460	(A)	$ 34.18	N/A	N/A

(A) 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	**2013**	2012	2011	2010	2009
SELECTED FINANCIAL DATA					
(In millions, except per share data)					
Results of Operations Data:					
Operating revenues	**$ 2,867.7**	$ 3,671.2	$ 3,915.9	$ 3,716.9	$ 2,869.7
Cost of sales	**1,428.9**	1,918.7	2,277.9	2,187.4	1,557.7
Operating expenses	**885.3**	1,075.6	991.3	935.6	820.1
Operating income	**553.5**	676.9	646.7	593.9	491.9
Equity in earnings of unconsolidated affiliates	**101.9**	—	—	—	—
Allowance for equity funds used during construction	**6.6**	6.2	20.4	11.4	15.1
Other income	**31.8**	17.6	19.8	13.7	28.9
Other expense	**22.2**	16.5	21.7	17.9	16.3
Interest expense	**147.5**	164.1	140.9	139.7	137.4
Income tax expense	**130.3**	135.1	160.7	161.0	121.1
Net income	**393.8**	385.0	363.6	300.4	261.1
Less: Net income attributable to noncontrolling interests	**6.2**	30.0	20.7	5.1	2.8
Net income attributable to OGE Energy	**$ 387.6**	$ 355.0	$ 342.9	$ 295.3	$ 258.3
Basic earnings per average common share attributable to OGE Energy common shareholders	**$ 1.96**	$ 1.80	$ 1.75	$ 1.51	$ 1.34
Diluted earnings per average common share attributable to OGE Energy common shareholders	**$ 1.94**	$ 1.79	$ 1.73	$ 1.49	$ 1.33
Dividends declared per common share	**$ 0.85125**	$ 0.79750	$ 0.75875	$ 0.73125	$ 0.71375
Balance Sheet Data (at period end):					
Property, plant and equipment, net	**$ 6,672.8**	$ 8,344.8	$ 7,474.0	$ 6,464.4	$ 5,911.6
Total assets	**$ 9,134.7**	$ 9,922.2	$ 8,906.0	$ 7,669.1	$ 7,266.7
Long-term debt	**$ 2,400.1**	$ 2,848.6	$ 2,737.1	$ 2,362.9	$ 2,088.9
Total stockholders' equity	**$ 3,037.1**	$ 3,072.4	$ 2,819.3	$ 2,400.0	$ 2,060.8
Capitalization Ratios (A)					
Stockholders' equity	**55.9%**	51.9%	50.7%	50.4%	46.4%
Long-term debt	**44.1%**	48.1%	49.3%	49.6%	53.6%
Ratio of Earnings to Fixed Charges (B)					
Ratio of earnings to fixed charges	**4.30**	3.94	4.12	4.02	3.38

(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 two business segments: (i) electric utility and (ii) natural gas midstream operations. For a discussion of the change in the Company’s business segments due to the formation of Enable, see Note 14 of Notes to Consolidated Financial Statements. For periods prior to May 1, 2013, the Company consolidated Enogex Holdings in its Condensed Consolidated Financial Statements.

Effective May 1, 2013, OGE Energy, the ArcLight group and CenterPoint Energy, Inc., formed Enable Midstream Partners, LP to own and operate the midstream businesses of OGE Energy and CenterPoint. In the formation transaction, OGE Energy and ArcLight group contributed Enogex LLC to Enable and the Company deconsolidated its previously held investment in Enogex Holdings and acquired an equity interest in Enable. The Company determined that its contribution of Enogex LLC to Enable met the requirements of being in substance real estate and was recorded at historical cost. The general partner of Enable is equally controlled by CenterPoint and OGE Energy, who each have 50 percent of the management rights. Based on the 50/50 management ownership, with neither company having control, effective May 1, 2013, OGE Energy began accounting for its interest in Enable using the equity method of accounting. At December 31, 2013, OGE Energy, through its wholly owned subsidiary OGE Holdings, holds 28.5 percent of the limited partner interests in Enable. OGE Energy also owns a 60 percent interest in any incentive distribution rights in Enable. Incentive distribution rights are expected to entitle the holder to increasing percentages, up to a maximum of 50 percent, of the cash distributed by Enable in excess of the target quarterly distributions to be set in connection with Enable’s initial public offering.

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.

The natural gas midstream operations segment consists of the Company's investment in Enable. Enable is engaged in the business of gathering, processing, transporting and storing natural gas. Enable's natural gas gathering and processing assets are strategically located in four states and serve natural gas production from shale developments in the Anadarko, Arkoma and Ark-La-Tex basins. Enable also owns an emerging crude oil gathering business in the Bakken shale formation that commenced initial operations in November 2013. Enable is continuing to construct additional crude oil gathering capacity in this area. Enable's natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

The Company completed a 2-for-1 stock split of the Company's common stock effective July 1, 2013. All share and per share amounts within this Form 10-K reflect the effects of the stock split.

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.

Enable's primary business objective is to practice operational excellence and to grow its business responsibly, increasing the amount of cash distributions made to its unitholders over time while maintaining financial stability. Strategies to accomplish this objective include capitalizing on organic growth opportunities and leveraging the scale of its existing assets, utilizing long-term, fee-based contracts to minimize direct commodity price exposure and maintaining strong customer relationships to attract new volumes and expand beyond its existing footprint and business lines. Enable also plans to grow through accretive acquisitions and disciplined development.

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 of approximately 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

2013 compared to 2012. Net income attributable to OGE Energy was $387.6 million, or $1.94 per diluted share, in 2013 as compared to $355.0 million, or $1.79 per diluted share, in 2012. The increase in net income attributable to OGE Energy of $32.6 million, or 9.2 percent, or $0.15 per diluted share, in 2013 as compared to 2012 was primarily due to:

- an increase in net income at OG&E of $12.3 million, or 4.4 percent, or $0.06 per diluted share of the Company's common stock, driven by higher gross margin primarily related to increased wholesale transmission revenue and lower other operation and maintenance expense, partially offset by higher interest expense related to the issuance of debt in May 2013;
- an increase in net income at OGE Holdings of $25.8 million, or 34.8 percent, or $0.13 per diluted share of the Company's common stock, due partially to the accretive effect to OGE Holdings of its investment in Enable since May 1, 2013 and a reduction in deferred state income taxes, associated with a remeasurement of the accumulated deferred taxes related to the formation of Enable. Also contributing to the increase was the performance of Enogex for the first four months of 2013. Compared to the same period of 2012, earnings were higher for Enogex due to increased gathering rates and volumes and inlet processing volumes associated with its expansion projects and gas gathering assets acquired in August 2012. These increases were partially offset by lower NGLs prices, lower keep-whole processing spreads and the contract conversion of the Texas production volumes of one of Enogex's five largest customers from keep-whole to fixed-fee; and
- a decrease in net income at OGE Energy of $5.5 million, or $0.04 per diluted share of the Company's common stock, primarily due to transaction expenses related to the formation of Enable as discussed in Note 3 of Notes to Condensed Consolidated Financial Statements.

2012 compared to 2011. Net income attributable to OGE Energy was $355.0 million, or $1.79 per diluted share, in 2012 as compared to $342.9 million, or $1.73 per diluted share, in 2011. The increase in net income attributable to OGE Energy of $12.1 million, or 3.5 percent, or $0.06 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 $0.09 per diluted share of the Company's common stock, primarily due to a higher gross margin primarily due to increased recovery of investments and increased transmission revenue partially offset by milder weather in OG&E's service territory. The increase in gross margin was partially offset by higher depreciation and amortization expense related to additional assets being placed in service and lower allowance for equity funds used during construction related to higher levels of construction costs for the Crossroads wind farm in 2011;
- an increase in net income of Enogex LLC of $0.7 million, which was offset by an $8.9 million increase in net income attributable to noncontrolling interests, resulting in a decrease in net income attributable to OGE Holdings

of $8.2 million, or 9.9 percent, or $0.04 per diluted share of the Company's common stock. The increase in net income attributable to noncontrolling interests reflected a reduction in the Company's ownership percentage of Enogex LLC due to increased capital contributions from the ArcLight group. The improvement in Enogex LLC's net income reflected higher operating income on increased gathering rates and volumes associated with ongoing expansion projects, increased volumes from gas gathering assets acquired in November 2011 and August 2012 and increased inlet volumes, which were partially offset by lower average natural gas and NGLs prices. Also contributing to the favorable results were a higher gain on insurance proceeds in 2012 and an impairment charge related to the Atoka processing plant in 2011 which did not occur in 2012. These improvements were partially offset by increased depreciation and amortization expense due to additional assets being placed in service throughout 2011 and 2012, higher other operations and maintenance expenses, and higher taxes other than income related to sales taxes on assets acquired; and

- an increase in net income at OGE Energy of $3.3 million, or $0.01 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.

A more detailed discussion regarding the financial performance of OG&E and the Natural Gas Midstream Operations can be found under "Results of Operations" below.

2014 Outlook

The Company's 2014 earnings guidance is between approximately $388 million and $411 million of net income, or $1.94 to $2.06 per average diluted share.

Key assumptions for 2014 include:

Consolidated OGE

- Approximately 200 million average diluted shares outstanding;
- An effective tax rate of approximately 30 percent; and
- A projected loss at the holding company of $2 million or $0.01 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 $292 million to $303 million, or $1.46 to $1.52 per average diluted share in 2014 and is based on the following assumptions:

- Normal weather patterns are experienced for the remainder of the year;
- Gross margin on revenues of approximately $1.355 billion to $1.345 billion based on sales growth of approximately 1.2 percent on a weather-adjusted basis;
- Approximately $115 million of gross margin is primarily attributed to regionally allocated transmission projects;
- Operating expenses of approximately $805 million to $815 million, with operation and maintenance expenses comprising 56 percent of the total;
- Interest expense of approximately $141 million which assumes a $4 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 2014;
- Other income of approximately $14 million including approximately $11 million of AEFUDC; 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.

OGE Enogex Holdings LLC

The Company projects equity earnings from its ownership interest in Enable to be between approximately $98 million to $110 million, or $0.49 to $0.55 per average diluted share. The outlook does not include any gains recognized each time Enable sells units representing the difference between book value and the unit sales price or the dilution associated with the issuance of limited partnership units from the planned Enable Midstream initial public offering.

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, 2013, 2012 and 2011 and the Company's consolidated financial position at December 31, 2013 and 2012. 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)*	**2013**	2012	2011
Operating income	**$ 553.5**	$ 676.9	$ 646.7
Net income attributable to OGE Energy	**$ 387.6**	$ 355.0	$ 342.9
Basic average common shares outstanding	**198.2**	197.1	195.8
Diluted average common shares outstanding	**199.4**	198.1	198.5
Basic earnings per average common share attributable to OGE Energy common shareholders	**$ 1.96**	$ 1.80	$ 1.75
Diluted earnings per average common share attributable to OGE Energy common shareholders	**$ 1.94**	$ 1.79	$ 1.73
Dividends declared per common share	**$ 0.8513**	$ 0.7975	$ 0.7588

In reviewing its consolidated operating results, the Company believes that it is appropriate to focus on operating income and equity in earnings of unconsolidated affiliates as reported in its Consolidated Statements of Income as those measures indicate the ongoing profitability of the Company excluding the cost of capital and income taxes.

Operating Results by Business Segment

Year ended December 31 *(In millions)*	**2013**	2012	2011
Operating Income (Loss)			
OG&E (Electric Utility)	**$ 525.3**	$ 489.4	$ 472.3
OGE Holdings (Natural Gas Midstream Operations) (A)	**33.2**	185.6	175.1
Other Operations (B)	**(5.0)**	1.9	(0.7)
Consolidated operating income	**$ 553.5**	$ 676.9	$ 646.7
Equity in Earnings of Unconsolidated Affiliate			
OGE Holdings (Natural Gas Midstream Operations) (A)	**$ 101.9**	$ —	$ —

(A) The former natural gas transportation and storage segment and natural gas gathering and processing segment have been combined into the natural gas midstream operations 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 results 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)*	**2013**	2012	2011
Operating revenues	**$ 2,262.2**	$ 2,141.2	$ 2,211.5
Cost of sales	**965.9**	879.1	1,013.5
Other operation and maintenance	**438.8**	446.3	436.0
Depreciation and amortization	**248.4**	248.7	216.1
Taxes other than income	**83.8**	77.7	73.6
Operating income	**525.3**	489.4	472.3
Allowance for equity funds used during construction	**6.6**	6.2	20.4
Other income	**8.1**	8.2	8.5
Other expense	**4.6**	4.3	8.4
Interest expense	**129.3**	124.6	111.6
Income tax expense	**113.5**	94.6	117.9
Net income	**$ 292.6**	$ 280.3	$ 263.3
Operating revenues by classification			
Residential	**$ 901.4**	$ 878.0	$ 943.5
Commercial	**554.2**	523.5	531.3
Industrial	**220.6**	206.8	216.0
Oilfield	**176.4**	163.4	165.1
Public authorities and street light	**214.3**	202.4	207.4
Sales for resale	**59.4**	54.9	65.3
System sales revenues	**2,126.3**	2,029.0	2,128.6
Off-system sales revenues	**14.7**	36.5	36.2
Other	**121.2**	75.7	46.7
Total operating revenues	**$ 2,262.2**	$ 2,141.2	$ 2,211.5
Reconciliation of gross margin to revenue:			
Operating revenues	2,262.2	2,141.2	2,211.5
Cost of sales	965.9	879.1	1,013.5
Gross Margin	1,296.3	1,262.1	1,198.0
MWH sales by classification *(In millions)*			
Residential	**9.4**	9.1	9.9
Commercial	**7.1**	7.0	6.9
Industrial	**3.9**	4.0	3.9
Oilfield	**3.4**	3.3	3.2
Public authorities and street light	**3.2**	3.3	3.2
Sales for resale	**1.2**	1.3	1.4
System sales	**28.2**	28.0	28.5
Off-system sales	**0.4**	1.4	1.0
Total sales	**28.6**	29.4	29.5
Number of customers	**806,940**	798,110	789,146
Weighted-average cost of energy per kilowatt-hour - cents			
Natural gas	**3.905**	2.930	4.328
Coal	**2.273**	2.310	2.064
Total fuel	**2.784**	2.437	2.897
Total fuel and purchased power	**3.178**	2.806	3.215
Degree days (A)			
Heating - Actual	**3,673**	2,667	3,359
Heating - Normal	**3,349**	3,349	3,631
Cooling - Actual	**2,106**	2,561	2,776
Cooling - Normal	**2,092**	2,092	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.

2013 compared to 2012. OG&E's operating income increased $35.9 million, or 7.3 percent, in 2013 as compared to 2012 primarily due to a higher gross margin, lower other operation and maintenance expense and lower depreciation and amortization expense partially offset by higher taxes other than income.

Gross Margin

Gross Margin is defined by OG&E as operating revenues less fuel, purchased power and transmission expenses. Gross margin is a non-GAAP financial measure because it excludes depreciation and amortization, and other operation and maintenance expenses. Expenses for fuel, purchased power and transmission expenses are recovered through fuel adjustment clauses and as a result changes in these expenses are offset in operating revenues with no impact on net income. OG&E believes gross margin provides a more meaningful basis for evaluating its operations across periods than operating revenues because gross margin excludes the revenue effect of fluctuations in these expenses. Gross margin is used internally to measure performance against budget and in reports for management and the Board of Directors. OG&E's definition of gross margin may be different from similar terms used by other companies.

Operating revenues were $2,262.2 million in 2013 as compared to $2,141.2 million in 2012, an increase of $121.0 million, or 5.7 percent. Cost of sales were $965.9 million in 2013 as compared to $879.1 million in 2012, an increase of $86.8 million, or 9.9 percent. Gross margin was $1,296.3 million in 2013 as compared to $1,262.1 million in 2012, an increase of $34.2 million, or 2.7 percent. The below factors contributed to the change in gross margin:

	$ Change
	(In millions)
Wholesale transmission revenue (A)	$ 44.9
New customer growth	10.9
Other	1.8
Non-residential demand and related revenues	0.1
Quantity variance (primarily weather)	(6.4)
Price variance (B)	(17.1)
Change in gross margin	$ 34.2

(A) Increased primarily due to higher investments related to certain FERC approved transmission projects included in formula rates.
(B) Decreased primarily due to sales and customer mix.

Cost of sales for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was $672.7 million in 2013 as compared to $642.4 million in 2012, an increase of $30.3 million, or 4.7 percent, primarily due to higher natural gas prices. OG&E's electric generating capability is fairly evenly divided between coal and natural gas and provides for flexibility to use either fuel to the best economic advantage for OG&E and its customers. In 2013, OG&E's fuel mix was 53 percent coal, 40 percent natural gas and seven percent wind. In 2012, OG&E's fuel mix was 52 percent coal, 42 percent natural gas and six percent wind. Purchased power costs were $267.6 million in 2013 as compared to $223.0 million in 2012, an increase of $44.6 million, or 20.0 percent, primarily due to an increase in purchases in the energy imbalance service market and short-term power agreements. Transmission related charges were $25.6 million in 2013 as compared to $13.7 million in 2012, an increase of $11.9 million, or 86.9 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 its affiliate, Enable.

Operating Expenses

Other operation and maintenance expenses were $438.8 million in 2013 as compared to $446.3 million in 2012, a decrease of $7.5 million, or 1.7 percent. The below factors contributed to the change in other operations and maintenance expense:

		$ Change
		(In millions)
Employee benefits (A)	$	(12.3)
Total salaries and wages (B)		(6.5)
Temporary labor		(2.3)
Contract professional services (primarily smart grid) (C)		(1.7)
Other		0.6
Other marketing and sales expense (primarily lower demand-side management initiatives) (C)		1.2
Administrative and assessment fees (primarily SPP Administration Fees)		2.2
Software expense (primarily smart grid) (C)		2.7
Capitalized labor		8.6
Change in other operation and maintenance expense	$	(7.5)

(A) Decreased primarily due to lower recoverable amounts of pension expense and postretirement medical expense allowed in the August 2012 rate case, a decrease in medical expense, and a decrease in worker's compensation accruals.

(B) Decreased primarily due to lower salaries and wages as a result of lower headcount in 2013 and a decrease in incentive pay, partially offset by annual salary increases and an increase in overtime wages related to 2013 storms.

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

Depreciation and amortization expense was $248.4 million in 2013 as compared to $248.7 million in 2012, a decrease of $0.3 million, primarily due to the amortization of the deferred pension credits regulatory liability and a decrease in the amortization of the storm regulatory asset (see Note 1). These decreases in depreciation and amortization expense were partially offset by:

- increases in depreciation rates from the August 2012 rate case; and
- additional assets being placed in service throughout 2013 and 2012, including the Sooner-Rose Hill and Sunnyside-Hugo transmission projects, which were fully in service in April 2012, the smart grid project which was completed in late 2012 and the Cleveland to Sooner transmission project which was fully in service in February 2013.

Taxes other than income was $83.8 million in 2013 as compared to $77.7 million in 2012, an increase of $6.1 million, or 7.9 percent, primarily due to higher ad valorem taxes.

Additional Information

Interest Expense. Interest expense was $129.3 million in 2013 as compared to $124.6 million in 2012, an increase of $4.7 million, or 3.8 percent, primarily due to a $6.4 million increase in interest on long term debt related to a $250 million debt issuance that occurred in May 2013, partially offset by a $2.0 million decrease in interest related to tax matters.

Income Tax Expense. Income tax expense was $113.5 million in 2013 as compared to $94.6 million in 2012, an increase of $18.9 million, or 20.0 percent primarily due to higher pre-tax income and a reserve related to a portion of the Oklahoma investment tax credits generated in years prior to 2013 but not yet utilized.

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. Fuel and purchased power 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.

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.

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.

OGE Holdings (Natural Gas Midstream Operations)

	December 31,		
(In millions)	**2013**	2012	2011
Operating revenues	**$ 630.4**	$ 1,608.6	$ 1,787.1
Cost of sales	**489.0**	1,120.1	1,346.6
Other operation and maintenance	**60.9**	172.9	162.5
Depreciation and amortization	**36.8**	108.8	77.6
Impairment of assets	**—**	0.4	6.3
Gain on insurance proceeds	**—**	(7.5)	(3.0)
Taxes other than income	**10.5**	28.3	22.0
Operating income (loss)	**33.2**	185.6	175.1
Equity in earnings of unconsolidated affiliates	**101.9**	—	—
Other income	**10.2**	1.0	3.9
Other expense	**1.3**	4.5	1.3
Interest expense	**10.6**	32.6	22.9
Income tax expense	**26.9**	45.7	51.7
Net income	**106.5**	103.8	103.1
Less: Net income attributable to noncontrolling interests	**6.6**	29.7	20.8
Net income attributable to OGE Holdings	**$ 99.9**	$ 74.1	$ 82.3

Effective May 1, 2013, the Company deconsolidated its previously held investment in Enogex Holdings and acquired a 28.5 percent equity interest in Enable which is being accounted for using the equity method of accounting. The former natural gas transportation and storage segment and natural gas gathering and processing segment have been combined into the natural gas midstream operations segment and have been restated for all prior periods presented. All financial statement line items included in the table above (except equity in earnings of unconsolidated affiliates and income tax expense) reflect 2013 operations only through April 30, 2013 and are not comparable to the prior year due to the deconsolidation discussed above.

Year Ended December 31, 2013 as Compared to Year Ended December 31, 2012

	Natural Gas Midstream Operations (Consolidated - Four Months Ended April 30, 2013)	**OGE Holdings (**Equity Method - Eight Months Ended December 31, 2013)	**Total** (Year Ended December 31, 2013)	**Natural Gas Midstream Operations** (Consolidated - Year Ended December 31, 2012)
(In millions)				
Operating revenues	**$ 630.4**	**$ —**	**$ 630.4**	$ 1,608.6
Cost of sales	**489.0**	**—**	**489.0**	1,120.1
Operating expenses	**108.2**	**—**	**108.2**	302.9
Operating income	**33.2**	**—**	**33.2**	185.6
Equity in earnings of unconsolidated affiliates	**—**	**101.9**	**101.9**	—
Income tax expense	**9.4**	**17.5**	**26.9**	45.7
Net income	**15.5**	**84.4**	**99.9**	74.1

OGE Holdings' results of operations for the four months ended April 2013 as compared to the same period of 2012 decreased due to lower NGLs prices, lower keep-whole processing spreads and the contract conversion of the Texas production volumes of one of Enogex LLC's five largest customers from keep-whole to fixed-fee, in addition to slightly higher other operation and maintenance expense and depreciation and amortization expense. These decreases were partially offset by increased gathering rates and volumes and inlet processing volumes associated with ongoing Enogex LLC expansion projects and the gas gathering assets acquired in August 2012.

Enable's results for the eight months ended December 31, 2013, were consistent with management's expectations in light of lower natural gas liquids prices and low seasonal and geographic price differentials. Enable continued to increase processing volumes through system expansions. Transportation throughput was impacted by system integrity projects and slightly lower demand. Gathering throughput was slightly lower, impacted by well connects, with lower throughput offset by the impact of minimum commitment features.

Income taxes in 2013 as compared to the same period in 2012 decreased due to a $16.4 million reduction in deferred state income taxes, associated with a remeasurement of the accumulated deferred taxes related to the formation of Enable partially offset by deferred tax adjustments related to the Company's deconsolidation of Enogex Holdings and higher pre-tax income (net of noncontrolling interest).

Operating Data

	Four Months Ended	Year Ended December 31,	
	April 30, 2013	2012	2011
Gathered volumes – TBtu/d	**1.54**	1.41	1.36
Incremental transportation volumes – TBtu/d (A)	**0.63**	0.67	0.58
Total throughput volumes – TBtu/d	**2.17**	2.08	1.94
Natural gas processed – TBtu/d	**1.10**	0.98	0.79
Condensate sold – million gallons	**17**	35	27
Average condensate sales price per gallon	**$ 1.95**	$ 1.95	$ 2.09
NGLs sold (keep-whole) – million gallons	**(99)**	162	167
NGLs sold (purchased for resale) – million gallons	**316**	667	487
NGLs sold (percent-of-liquids) – million gallons	**7**	24	25
NGLs sold (percent-of-proceeds) – million gallons	**5**	14	6
Total NGLs sold – million gallons	**229**	867	685
Average NGLs sales price per gallon	**$ 1.08**	$ 0.89	$ 1.16
Average natural gas sales price per MMBtu	**$ 3.48**	$ 2.79	$ 4.08

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

Enable Operating Data during the Eight Months Ended December 31, 2013

	Eight Months Ended December 31, 2013
Gathered volumes - TBtu/d (A)	3.5
Transportation volumes - TBtu/d	4.6
Natural gas processed - TBtu/d	1.5
NGLs sold - million gallons/d	2.6

(A) Excludes volumes billed under throughput agreements.

Enable Results of Operations during the Eight Months Ended December 31, 2013

	Eight Months Ended December 31, 2013
Operating revenues	$ 2,122.6
Cost of sales	1,240.5
Operating income	321.9
Net income	288.6

Equity in earnings of unconsolidated affiliates includes OGE Energy's 28.5 percent share of Enable earnings adjusted for the amortization of the basis difference of OGE Energy's original investment in Enogex and its underlying equity in net assets of Enable, based on historical cost as of May 1, 2013. The basis difference is being amortized over approximately 30 years, the average life of the assets to which the basis difference is attributed. Equity in earnings of unconsolidated affiliates is also adjusted for the elimination of the Enogex Holdings fair value adjustments.

Reconciliation of Equity in Earnings of Unconsolidated Affiliates

		Eight Months Ended December 31, 2013
OGE's 28.5% share of Enable Net Income	$	82.1
Amortization of basis difference		9.4
Elimination of Enogex Holdings fair value and other adjustments		10.4
OGE's Equity in earnings of unconsolidated affiliates	$	101.9

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:

- increased gathering rates and volumes associated with ongoing expansion projects and increased volumes from as gathering assets acquired in November 2011 and August 2012;
- 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;
- 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 as discussed below; and
- lower impairment of assets as discussed below.

These increases were partially offset by lower average natural gas and NGLs prices, higher other operation and maintenance expense, higher depreciation and amortization expense and higher taxes other than income. In 2012, imbalance volume changes and realized margin on physical gas long/short positions decreased the operating income 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.

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 $2.3 million 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.

Off-Balance Sheet Arrangement

OG&E Railcar Lease Agreement

OG&E has a noncancellable operating lease with purchase options, covering 1,389 coal rotary gondola railcars to transport coal from Wyoming to OG&E's coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through OG&E's tariffs and fuel adjustment clauses. On December 15, 2010, OG&E renewed the lease agreement effective February 1, 2011. At the end of the new lease term, which is February 1, 2016, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual fair value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of $22.8 million. OG&E is also required to maintain all of the railcars it has under the operating lease and has entered into an agreement with a non-affiliated company to furnish this maintenance.

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 has a unilateral right to terminate this lease upon a 6-month notice effective April 2015 and April 2016.

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 $250.5 million and $352.7 million at December 31, 2013 and 2012, respectively, a decrease of $102.2 million, or 29.0 percent, primarily due to the deconsolidation of Enogex Holdings on May 1, 2013 partially offset by higher transmission revenue, an increase in billings for reimbursable construction costs and an increase in billings to partners of jointly-owned power plants,

The balance of Accounts Payable was $251.0 million and $396.7 million at December 31, 2013 and 2012, respectively, a decrease of $145.7 million, or 36.7 percent, primarily due to the deconsolidation of Enogex Holdings on May 1, 2013 partly offset by increases primarily due to the timing of vendor payments and an increase in accruals.

Cash Flows

				2013 vs. 2012		2012 vs. 2011	
Year ended December 31 *(In millions)*	**2013**	2012	2011	$ Change	% Change	$ Change	% Change
Net cash provided from operating activities	**$ 623.2**	$ 1,046.1	$ 833.9	$ (422.9)	(40.4)%	$ 212.2	25.4 %
Net cash used in investing activities	**(957.0)**	(1,192.6)	(1,395.8)	235.6	19.8 %	203.2	(14.6)%
Net cash provided from financing activities	**338.8**	143.7	564.2	195.1	*	(420.5)	(74.5)%

* Percentage is greater than 100 percent.

Operating Activities

The decrease of $422.9 million, or 40.4 percent, in net cash provided from operating activities in 2013 as compared to 2012 was primarily due to:

- fuel refunds at OG&E in 2013 as compared to higher fuel recoveries in 2012;
- the deconsolidation of Enogex Holdings on May 1, 2013.

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 LLC during 2012 as compared to 2011 partially offset by lower natural gas and NGLs prices in 2012 as compared to 2011.

Investing Activities

The decrease of $235.6 million, or 19.8 percent, in net cash used in investing activities in 2013 as compared to 2012 is primarily a result of decreased capital expenditures related to the deconsolidation of Enogex Holdings on May 1, 2013 partially offset by increased capital expenditures at OG&E in 2013 related to various transmission projects.

The decrease of $203.2 million, or 14.6 percent, in net cash used in investing activities in 2012 as compared to 2011 primarily related 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 LLC.

Financing Activities

The increase of $195.1 million in net cash provided from financing activities in 2013 as compared to 2012 was primarily due to:

- a decrease in repayments of lines of credit in 2013 as compared to 2012;
- payments on advances from unconsolidated affiliates due to the deconsolidation of Enogex Holdings on May 1, 2013; and
- and higher contributions from the Arclight group related to the closing of the transaction to form Enable.

These increases in net cash provided from financing activities were partially offset by a decrease in short-term debt borrowings during 2013 as compared to 2012.

The decrease of $420.5 million 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 LLC's revolving credit agreement during 2011; and
- repayments of Enogex's line of credit during 2012.

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

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. Other working capital requirements are expected to be primarily related to maturing debt, operating lease obligations, fuel clause under and over recoveries and other general corporate purposes. The Company generally meets its cash needs through a combination of cash generated from operations, short-term borrowings (through a combination of bank borrowings and commercial paper) and permanent financings.

Capital Expenditures

The Company's consolidated estimates of capital expenditures for the years 2014 through 2018 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. The Company believes that Enable has, or will have, access to adequate liquidity and, therefore, no contributions are expected to be necessary to fund the capital expenditures of Enable from the general partners. Accordingly, capital expenditures for Enable are not included in the table below.

(In millions)	2014	2015	2016	2017	2018
OG&E Base Transmission	$ 30	$ 30	$ 30	$ 30	$ 30
OG&E Base Distribution	175	175	175	175	175
OG&E Base Generation	140	75	75	75	75
OG&E Other	15	15	15	15	15
Total OG&E Base Transmission, Distribution, Generation and Other	360	295	295	295	295
OG&E Known and Committed Projects:					
Transmission Projects:					
Regionally Allocated Base Projects (A)	55	20	20	20	20
Balanced Portfolio 3E Projects (B)(C)	15	—	—	—	—
SPP Priority Projects (B)(C)	75	—	—	—	—
SPP Integrated Transmission Projects (B) (C)	15	25	30	25	10
Total Transmission Projects	160	45	50	45	30
Other Projects:					
Smart Grid Program	25	10	10	—	—
Environmental - low NOX burners	35	20	15	10	—
Environmental - activated carbon injection	5	10	5	—	—
Total Other Projects	65	40	30	10	—
Total OG&E Known and Committed Projects	225	85	80	55	30
Total OG&E (D)	585	380	375	350	325
OGE Energy	15	10	10	10	10
Total capital expenditures	$ 600	$ 390	$ 385	$ 360	$ 335

(A) Approximately 30% of revenue requirement allocated to SPP members other than OG&E.
(B) Approximately 85% of revenue requirement allocated to SPP members other than OG&E.

(C)

Project Type	Project Description	Estimated Cost (In millions)	Projected In-Service Date
Balance Portfolio 3E	96 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to the Oklahoma /Texas Stateline to a companion transmission line to its Tuco substation	$110	Mid-2014
Priority Project	99 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to the western Beaver County line to a companion transmission line to its Hitchland substation	$165	Mid-2014
Priority Project	77 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to a companion transmission line at the Kansas border	$140	Late 2014
Integrated Transmission Project	47 miles of transmission line from OG&E's Gracemont substation to an AEP companion transmission line to its Elk City substation	$45	Early 2018
Integrated Transmission Project	126 miles of transmission line from OG&E's Woodward District Extra High Voltage substation to OG&E's Cimarron substation; construction of the Mathewson substation on this transmission line	$180	Early 2021

(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. On July 19, 2013, the U.S. Court of Appeals for the Tenth Circuit by a 2 to 1 vote denied the petition for review and affirmed the EPA's issuance of the FIP. On January 2, 2014, the Tenth Circuit confirmed that the stay of the FIP has remained in place and continues until the Tenth Circuit issues the mandate. A Petition for Certiorari was filed by the State of Oklahoma, the Industrial Consumers and OG&E with the United States Supreme Court on January 29, 2014. The mandate from the Tenth Circuit has been stayed until the Supreme Court acts on the petition. If the Supreme Court elects not to hear the case, OG&E will have approximately 55 months from the effective date of the lifting of the stay to achieve compliance with the FIP.

- Installation of control equipment (other than activated carbon injection) for compliance with MATS by a deadline of April 16, 2016, which includes a one-year extension which was granted by the Oklahoma Department of Environmental Quality. As noted above, OG&E is currently planning to utilize activated carbon injection for the removal of mercury at each of its five coal-fired units, the capital costs of which are estimated to be approximately $20 million over a three year period and are included in the capital expenditures table in "Future Capital Requirements and Financing Activities" above. OG&E continues to review whether additional controls such as dry sorbent injection are needed for compliance with MATS. Current capital costs for installing the necessary control equipment for dry sorbent injection are estimated to be approximately $45 million over a three year period, but due to the uncertainty as to whether or not dry sorbent injection is necessary, such costs are not included in the capital expenditures table in "Future Capital Requirements and Financing Activities" above.

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

Additional capital expenditures beyond those identified in the table above, including additional incremental growth opportunities in electric transmission assets will be evaluated based upon their impact upon achieving the Company's financial objectives.

Contractual Obligations

The following table summarizes the Company's contractual obligations at December 31, 2013. See the Company's Consolidated Statements of Capitalization and Note 15 of Notes to Consolidated Financial Statements for additional information.

(In millions)	2014	2015-2016	2017-2018	After 2018	Total
Maturities of long-term debt (A)	$ 100.2	$ 110.4	$ 375.2	$ 1,819.9	$ 2,405.7
Operating lease obligations					
Railcars	3.8	30.4	—	—	34.2
Wind farm land leases	2.1	4.2	4.8	48.8	59.9
OGE Energy noncancellable operating lease	0.8	1.6	1.5	—	3.9
Total operating lease obligations	6.7	36.2	6.3	48.8	98.0
Other purchase obligations and commitments					
Cogeneration capacity and fixed operation and maintenance payments	85.1	164.6	156.6	235.2	641.5
Expected cogeneration energy payments	61.1	136.6	168.9	352.5	719.1
Minimum fuel purchase commitments	451.8	820.3	385.1	—	1,657.2
Expected wind purchase commitments	58.0	118.7	120.3	368.9	665.9
Long-term service agreement commitments	70.5	5.3	21.7	187.9	285.4
Total other purchase obligations and commitments	726.5	1,245.5	852.6	1,144.5	3,969.1
Total contractual obligations	833.4	1,392.1	1,234.1	3,013.2	6,472.8
Amounts recoverable through fuel adjustment clause (B)	(574.7)	(1,106.0)	(674.3)	(721.4)	(3,076.4)
Total contractual obligations, net	$ 258.7	$ 286.1	$ 559.8	$ 2,291.8	$ 3,396.4

(A) Maturities of the Company's long-term debt during the next five years consist of $100.2 million, $0.2 million, $110.2 million$125.1 million and $250.1 million in years 2014, 2015, 2016, 2017 and 2018, 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.

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 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, 2013, 40.6 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 13 of Notes to Consolidated Financial Statements. In 2013, asset returns on the Pension Plan were 12.5 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, increased. During both 2013 and 2012, OGE Energy made contributions to its Pension Plan of $35 million to help ensure that the Pension Plan maintains an adequate funded status. The level of funding is dependent on returns on plan assets and future discount rates. During 2014, OGE Energy expects to contribute up to $26 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, 2013 and 2012. 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)*	**2013**	2012	**2013**	2012	**2013**	2012
Benefit obligations	**$ (658.1)**	$ (747.1)	**$ (14.0)**	$ (14.5)	**$ (258.2)**	$ (301.0)
Fair value of plan assets	**654.9**	626.0	**—**	—	**61.4**	59.6
Funded status at end of year	**$ (3.2)**	$ (121.1)	**$ (14.0)**	$ (14.5)	**$ (196.8)**	$ (241.4)

In accordance with ASC Topic 715, "Compensation - Retirement Benefits," a one-time settlement charge is required to be recorded by an organization when lump sum payments or other settlements that relieve the organization from the responsibility for the pension benefit obligation during a plan year exceed the service cost and interest cost components of the organization's net periodic pension cost. During 2013, the Company experienced an increase in both the number of employees electing to retire and the amount of lump sum payments to be paid to such employees upon retirement. As a result, and based in part on the Company's historical experience regarding eligible employees who elect to retire in the last quarter of a particular year, the Company recorded pension settlement charges of $22.4 million in the fourth quarter of 2013, of which $17.0 million related to OG&E's Oklahoma jurisdiction and has been included in the pension tracker. The pension settlement charge did not require a cash outlay by the Company and did not increase the Company's total pension expense over time, as the charges were an acceleration of costs that otherwise would be recognized as pension expense in future periods.

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 of approximately 60 percent of its normalized earnings on an annual basis. The target payout ratio has been determined after consideration of numerous factors, including the largely retail composition of the Company's shareholder base, the Company's financial position, the Company's growth targets, the composition of the Company's assets and investment opportunities. At the Company's December 2013 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 $0.22500 per share from $0.20875 per share effective with the Company's first quarter 2014 dividend.

Security Ratings

	Moody's Investors Services	Standard & Poor's Ratings Services	Fitch Ratings
OG&E Senior Notes	A1	A-	A+
OGE Energy Senior Notes	A3	BBB+	A-
OGE Energy Commercial Paper	P2	A2	F2

Access to reasonably priced capital is dependent in part on credit and security ratings. Generally, lower ratings lead to higher financing costs. Pricing grids associated with the Company's credit facilities could cause annual fees and borrowing rates to increase if an adverse rating impact occurs. The impact of any future downgrade could include an increase in the costs of the Company's short-term borrowings, but a reduction in the Company's credit ratings would not result in any defaults or accelerations. Any future downgrade could also lead to higher long-term borrowing costs and, if below investment grade, would require the Company to post collateral or letters of credit.

In conjunction with the closing of Enable on May 1, 2013, on May 2, 2013, Standard & Poor's Ratings Services upgraded the long-term senior unsecured rating of OGE Energy to BBB+ and OG&E to A-. All other security ratings from S&P remain unchanged.

On November 8, 2013, Moody's Investors Services placed the credit ratings of OGE Energy and OG&E on review for possible upgrade. On January 31, 2014, Moody's upgraded the long-term senior unsecured rating of OGE Energy to A3 and OG&E to A1 primarily due to their more favorable view of the relative credit supportiveness of the U.S. regulatory environment. All other security ratings from Moody's remain unchanged.

A security rating is not a recommendation to buy, sell or hold securities. Such rating may be subject to revision or withdrawal at any time by the credit rating agency and each rating should be evaluated independently of any other rating.

Future financing requirements may be dependent, to varying degrees, upon numerous factors such as general economic conditions, abnormal weather, load growth, commodity prices, acquisitions of other businesses and/or development of projects, actions by rating agencies, inflation, changes in environmental laws or regulations, rate increases or decreases allowed by regulatory agencies, new legislation and market entry of competing electric power generators.

2013 Capital Requirements, Sources of Financing and Financing Activities

Total capital requirements, consisting of capital expenditures and maturities of long-term debt, were $990.7 million and contractual obligations, net of recoveries through fuel adjustment clauses, were $96.4 million resulting in total net capital requirements and contractual obligations of $1,087.1 million in 2013, of which $42.0 million was to comply with environmental regulations. This compares to net capital requirements of $1,351.8 million and net contractual obligations of $112.8 million totaling $1,464.6 million in 2012, of which $12.9 million was to comply with environmental regulations.

In 2013, the Company's sources of capital were cash generated from operations, proceeds from the issuance of short-term debt, proceeds from the sales of common stock to the public through the Company's Automatic Dividend Reinvestment and Stock Purchase Plan, funding for growth opportunities at Enogex through the ArcLight group, distributions from Enogex Holdings and distributions from Enable. Changes in working capital reflect the seasonal nature of the Company's business, the revenue lag between billing and collection from customers and fuel inventories. See "Working Capital" for a discussion of significant changes in net working capital requirements as it pertains to operating cash flow and liquidity.

Issuance of Long-Term Debt

On May 8, 2013, OG&E issued $250 million of 3.9% senior notes due May 1, 2043. The proceeds from the issuance were added to OG&E's general funds and were used to repay short-term debt, to fund capital expenditures, to pay general corporate expenses and for working capital purposes.

Potential Collateral Requirements

Derivative instruments are utilized in managing OG&E's commodity price exposures. On July 21, 2010, President Obama signed into law the Dodd-Frank Act. Among other things, the Dodd-Frank Act provides for a new regulatory regime for derivatives, including mandatory clearing of certain swaps and margin requirements. The Dodd-Frank Act contains provisions that should exempt certain derivatives end-users such as OG&E from much of the clearing requirements. The regulations require that the decision on whether to use the end-user exception from mandatory clearing for derivative transactions be reviewed and approved by an "appropriate committee" of the Board of Directors. The scope of the margin requirements and their potential direct impact on OG&E remain unclear because final rules have not been issued. Further, even if OG&E qualifies for the end-user exception to clearing and margin requirements are not imposed on end-users, its derivative counterparties may be subject to new capital, margin and business conduct requirements as a result of the new regulations, which may increase OG&E's transaction costs or make it more difficult to enter into derivative transactions on favorable terms. OG&E's inability to enter into derivative transactions on favorable terms, or at all, could increase operating expenses and put OG&E at increased exposure to risks of adverse changes in commodities prices. The impact of the provisions of the Dodd-Frank Act on OG&E cannot be fully determined at this time due to uncertainty over forthcoming regulations and potential changes to the derivatives markets arising from new regulatory requirements.

Future Sources of Financing

Management expects that cash generated from operations, proceeds from the issuance of long and short-term debt, proceeds from the sales of common stock to the public through the Company's Automatic Dividend Reinvestment and Stock Purchase Plan or other offerings and distributions from Enable will be adequate over the next three years to meet anticipated cash needs and to fund future growth opportunities. 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 Company has revolving credit facilities totaling in the aggregate $1,150.0 million. These bank facilities can also be used as letter of credit facilities. The short-term debt balance was $439.6 million and $430.9 million at December 31, 2013 and 2012, respectively. The weighted-average interest rate on short-term debt at December 31, 2013 was 0.30 percent. The average balance of short-term debt in 2013 was $485.0 million at a weighted-average interest rate of 0.34 percent. The maximum month-end balance of short-term debt in 2013 was $663.9 million. At December 31, 2013, the Company had $715.1 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, 2013, the Company had $6.8 million in cash and cash equivalents. See Note 12 of Notes to Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

Effective May 1, 2013, Enable entered into a $1.4 billion, five-year senior unsecured revolving credit facility in accordance with the terms of the Master Formation Agreement and Enogex LLC's $400.0 million revolving credit facility was terminated.

In December 2011, the Company and OG&E entered into unsecured five-year revolving credit agreements to total in the aggregate $1,150.0 million ($750.0 million for the Company and $400.0 million for OG&E). Each of the credit facilities contain an option, which may be exercised up to two times, to extend the term for an additional year, subject to consent of a specified percentage of the lenders. Effective July 29, 2013, the Company and OG&E utilized one of these one-year extensions, and received consent from all of the lenders, to extend the maturity of their credit agreements to December 13, 2017.

Expected Issuance of Long-Term Debt

OG&E expects to issue up to $250 million of long-term debt during 2014, depending on market conditions, to fund capital expenditures, to repay short or long-term borrowings and for general corporate purposes.

Common Stock

The Company expects to issue between $10 million and $15 million of common stock in its Automatic Dividend Reinvestment and Stock Purchase Plan in 2014. See Note 10 of Notes to Consolidated Financial Statements for a discussion of the Company's common stock activity.

Distributions by Enable

Pursuant to the Enable limited partnership agreement, during 2013 Enable made distributions of approximately $51.7 million to the Company.

Critical Accounting Policies and Estimates

The Consolidated Financial Statements and Notes to Consolidated Financial Statements contain information that is pertinent to Management's Discussion and Analysis. In preparing the Consolidated Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the Company's Consolidated Financial Statements. However, the Company believes it has taken reasonable positions where assumptions and estimates are used in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised for all Company segments includes the determination of Pension Plan assumptions, impairment estimates of long-lived assets (including intangible assets) income taxes, contingency reserves, asset retirement obligations and assets and depreciable lives of property, plant and equipment. For the electric utility segment, the most significant judgment is also exercised in the existence of regulatory assets and liabilities and unbilled revenues. The selection, application and disclosure of the following critical accounting estimates have been discussed with the Company's Audit Committee. The Company discusses its significant accounting policies, including those that do not require management to make difficult, subjective, or complex judgments or estimates, in Note 1 of Notes to Consolidated Financial Statements.

Pension and Postretirement Benefit Plans

The Company has a Pension Plan that covers a significant amount of the Company's employees hired before December 1, 2009. Also, effective December 1, 2009, the Company's Pension Plan is no longer being offered to employees hired on or after December 1, 2009. The Company also has defined benefit postretirement plans that cover a significant amount of its employees. Pension and other postretirement plan expenses and liabilities are determined on an actuarial basis and are affected by the market value of plan assets, estimates of the expected return on plan assets, assumed discount rates and the level of funding. Actual changes in the fair market value of plan assets and differences between the actual return on plan assets and the expected return on plan assets could have a material effect on the amount of pension expense ultimately recognized. The pension plan rate assumptions are shown in Note 13 of Notes to Consolidated Financial Statements. The assumed return on plan assets is based on management's expectation of the long-term return on the plan assets portfolio. The discount rate used to compute the present value of plan liabilities is based generally on rates of high-grade corporate bonds with maturities similar to the average period over which benefits will be paid. The level of funding is dependent on returns on plan assets and future discount rates. Higher returns on plan assets and an increase in discount rates will reduce funding requirements to the Pension Plan. The following table indicates the sensitivity of the Pension Plan funded status to these variables.

	Change	Impact on Funded Status
Actual plan asset returns	+/- 1 percent	+/- $6.5 million
Discount rate	+/- 0.25 percent	+/- $18.3 million
Contributions	+/- $10 million	+/- $10 million

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

As a result of the formation of Enable Midstream Partners on May 1, 2013 and the Company's deconsolidation of Enogex Holdings, the Company no longer has intangible assets or goodwill.

The Company assesses its long-lived assets (inclusive of definite-lived intangible assets prior to the deconsolidation of Enogex Holdings) for impairment when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset's carrying amount. Estimates of future cash flows used to test the recoverability of long-lived assets and intangible assets shall include only the future cash flows (cash inflows less associated cash outflows) that are directly associated with and that are expected to arise as a direct result of the use and eventual disposition of the asset. The fair value of these assets is based on third-party evaluations, prices for similar assets, historical data and projected cash flows. An impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset. In 2011, the Company recorded a pre-tax impairment loss of $5.0 million, of which $2.5 million was the noncontrolling interest portion (see Note 4 of Notes to Consolidated Financial Statements), related to the Atoka processing plant. The Company recorded no other material impairments in 2013, 2012 or 2011.

Income Taxes

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

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

Commitments and Contingencies

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits 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.

Except as disclosed otherwise in this Form 10-K, 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. See Notes 15 and 16 of Notes to Consolidated Financial Statements and Item 3 of Part I in this Form 10-K for a discussion of the Company's commitments and contingencies.

Asset Retirement Obligations

The Company has previously recorded asset retirement obligations that are being amortized over their respective lives ranging from 20 to 74 years. The inputs used in the valuation of asset retirement obligations include the assumed life of the asset placed into service, the average inflation rate, market risk premium, the credit-adjusted risk free interest rate and the timing of incurring costs related to the retirement of the asset.

Hedging Policies

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

Hedges are evaluated prior to execution with respect to the impact on the volatility of forecasted earnings and are evaluated at least quarterly after execution for the impact on earnings.

Regulatory Assets and Liabilities

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

OG&E records certain actual or anticipated costs and obligations as regulatory assets or liabilities if it is probable, based on regulatory orders or other available evidence, that the cost or obligation will be included in amounts allowable for recovery or refund in future rates. The benefit obligations regulatory asset is comprised of expenses recorded which are probable of future recovery and that have not yet been recognized as components of net periodic benefit cost, including net loss, prior service cost and net transition obligation.

Unbilled Revenues

OG&E reads its customers' meters and sends bills to its customers throughout each month. As a result, there is a significant amount of customers' electricity consumption that has not been billed at the end of each month. Unbilled revenue is presented in Accrued Unbilled Revenues on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income based on estimates of usage and prices during the period. At December 31, 2013, if the estimated usage or price used in the unbilled revenue calculation were to increase or decrease by one percent, this would cause a change in the unbilled revenues recognized of $0.3 million. At December 31, 2013 and 2012, Accrued Unbilled Revenues were $58.7 million and $57.4 million, respectively. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

Allowance for Uncollectible Accounts Receivable

Customer balances are generally written off if not collected within six months after the final billing date. The allowance for uncollectible accounts receivable for OG&E is calculated by multiplying the last six months of electric revenue by the provision rate. The provision rate is based on a 12-month historical average of actual balances written off. To the extent the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. Also, a portion of the uncollectible provision related to fuel within the Oklahoma jurisdiction is being recovered through the fuel adjustment clause. At December 31, 2013, if the provision rate were to increase or decrease by 10 percent, this would cause a change in the uncollectible expense recognized of $0.2 million. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Consolidated Balance Sheets and is included in Other Operation and Maintenance Expense on the Consolidated Statements of Income. The allowance for uncollectible accounts receivable was $1.9 million and $2.6 million at December 31, 2013 and 2012, respectively.

Accounting Pronouncements

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

Commitments and Contingencies

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits 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 disclosed otherwise in this Form 10-K, 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. See Notes 15 and 16 of Notes to Consolidated Financial Statements and Item 3 of Part I in this Form 10-K for a discussion of the Company's commitments and contingencies.

Environmental Laws and Regulations

The activities of the Company are subject to stringent and complex Federal, state and local laws and regulations governing environmental protection relating to air quality, water quality, waste management, wildlife conservation and natural resources. These laws and regulations can restrict or impact business activities in many ways, such as restricting the way it can handle or dispose of its wastes, requiring remedial action to mitigate environmental issues that may be caused by its operations or that are attributable to former operators, requiring changes in operations and requiring the installation and operation of pollution control equipment. Failure to comply with these laws and regulations could result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations.

Environmental regulation can increase the cost of planning, design, initial installation and operation of OG&E's facilities. Historically, OG&E's total expenditures for environmental control facilities and for remediation have not been significant in relation to its consolidated financial position or results of operations. The Company believes, however, that it is reasonably likely that the trend in environmental legislation and regulations will continue towards more restrictive standards. Compliance with these standards is expected to increase the cost of conducting business. Management continues to evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

OG&E expects that environmental capital expenditures necessary to comply with the environmental laws and regulations discussed below will qualify as part of a regulatory plan to handle state and Federally mandated environmental upgrades which will be recoverable in Oklahoma from OG&E's retail customers under House Bill 1910, which was enacted into law in May 2005.

It is estimated that OG&E's total expenditures to comply with environmental laws, regulations and requirements for 2014 will be $72.6 million, of which $55.0 million is for capital expenditures. It is estimated that OG&E's total expenditures to comply with environmental laws, regulations and requirements for 2015 will be $49.6 million, of which $31.3 million is for capital expenditures. The amounts for OG&E above include capital expenditures for low NOX burners and activated carbon injection and exclude certain other capital expenditures as discussed in footnote D to the capital expenditures table in "Future Capital Requirements and Financing Activities" above.

Air

Federal Clean Air Act Overview

OG&E’s operations are subject to the Federal Clean Air Act, as amended, and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including electric generating units, and also impose various monitoring and reporting requirements. Such laws and regulations may require that OG&E obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions or result in the increase of existing air emissions, obtain and strictly comply with air permits containing various emissions and operational limitations or install emission control equipment. OG&E likely will be required to incur certain capital expenditures in the future for air pollution control equipment and technology in connection with obtaining and maintaining operating permits and approvals for air emissions.

Regional Haze Control Measures

On June 15, 2005, the EPA issued final amendments to its 1999 regional haze rule. Regional haze is visibility impairment caused by the cumulative air pollutant emissions from numerous sources over a wide geographic area.

As required by the Federal regional haze rule, the state of Oklahoma evaluated the installation of BART to reduce emissions that cause or contribute to regional haze from certain sources within the state that were built between 1962 and 1977. On February 18, 2010, Oklahoma submitted its SIP to the EPA, which set forth the state's plan for compliance with the Federal regional haze rule. The SIP was subject to the EPA's review and approval.

The Oklahoma SIP included requirements for reducing emissions of NOX and SO2 from OG&E's seven BART-eligible units at the Seminole, Muskogee and Sooner generating stations. The SIP also included a waiver from BART requirements for all eligible units at the Horseshoe Lake generating station based on air modeling that showed no significant impact on visibility in nearby national parks and wilderness areas. The SIP concluded that BART for reducing NOX emissions at all of the subject units should be the installation of low NOX burners with overfire air (flue gas recirculation was also required on two of the units) and set forth associated NOX emission rates and limits. OG&E preliminarily estimates that the total capital cost of installing and operating these NOX controls on all covered units, based on recent industry experience and past projects, will be approximately $80 million. With respect to SO2 emissions, the SIP included an agreement between the Oklahoma Department of Environmental Quality and OG&E that established BART for SO2 control at the four affected coal-fired units located at OG&E's Sooner and Muskogee generating stations as the continued use of low sulfur coal (along with associated emission rates and limits). The SIP specifically rejected the installation and operation of Dry Scrubbers as BART for SO2 control from these units because the state determined that Dry Scrubbers were not cost effective on these units.

On December 28, 2011, the EPA issued a final rule in which it rejected portions of the Oklahoma SIP and issued a FIP in their place. While the EPA accepted Oklahoma's BART determination for NOX in the final rule, it rejected Oklahoma's SO2 BART determination with respect to the four coal-fired units at the Sooner and Muskogee generating stations. The EPA is instead requiring that OG&E meet an SO2 emission rate of 0.06 pounds per MMBtu within five years. OG&E could meet the proposed standard by either installing and operating Dry Scrubbers or fuel switching at the four affected units. OG&E estimates that installing Dry Scrubbers on these units would include capital costs to OG&E of more than $1.0 billion. OG&E and the state of Oklahoma filed an administrative stay request with the EPA on February 24, 2012. The EPA has not yet responded to this request. OG&E and other parties also filed a petition for review of the FIP in the U.S. Court of Appeals for the Tenth Circuit on February 24, 2012 and a stay request on April 4, 2012. On June 22, 2012, the U.S. Court of Appeals for the Tenth Circuit granted the stay request. On July 19, 2013, the U.S. Court of Appeals for the Tenth Circuit by a 2 to 1 vote denied the petition for review and affirmed the EPA's issuance of the FIP. On January 2, 2014, the Tenth Circuit confirmed that the stay of the FIP has remained in place and continues until the Tenth Circuit issues the mandate. A Petition for Certiorari was filed by the State of Oklahoma, the Industrial Consumers and OG&E with the United States Supreme Court on January 29, 2014. The mandate from the Tenth Circuit has been stayed until the Supreme Court acts on the petition. If the Supreme Court elects not to hear the case, OG&E will have approximately 55 months from the effective date of the lifting of the stay to achieve compliance with the FIP.

Cross-State Air Pollution Rule

As previously reported, on July 7, 2011, the EPA finalized its Cross-State Air Pollution Rule to replace the former Clean Air Interstate Rule that was remanded by a Federal court as a result of legal challenges. The final rule would require 27 states to reduce power plant emissions that contribute to ozone and particulate matter pollution in other states. On December 27, 2011, the EPA published a supplemental rule, which would make six additional states, including Oklahoma, subject to the Cross-State Air Pollution Rule for NOX emissions during the ozone-season from May 1 through September 30. Under the rule, OG&E would have been required to reduce ozone-season NOX emissions from its electrical generating units within the state beginning in 2012. The Cross-State Air Pollution Rule was challenged in court by numerous states and power generators. On December 30, 2011, the U.S. Court of Appeals issued a stay of the rule, which includes the supplemental rule, pending a decision on the merits. By order dated August 21, 2012, the U.S. Court of Appeals vacated the Cross-State Air Pollution Rule and ordered the EPA to promulgate a replacement rule. On June 24, 2013, the U.S. Supreme Court agreed to review the decision by the U.S. Court of Appeals, with a decision expected during the first half of 2014. OG&E cannot predict the outcome of such challenges.

Hazardous Air Pollutants Emission Standards

On April 16, 2012, regulations governing emissions of certain hazardous air pollutants from electric generating units were published as the final MATS rule. This rule includes numerical standards for particulate matter (as a surrogate for toxic metals), hydrogen chloride and mercury emissions from coal-fired boilers. In addition, the regulations include work practice standards for dioxins and furans. Compliance with the MATS rule is required within three years after the effective date of the rule with the possibility of a one-year extension. OG&E requested and was granted a one-year extension by the Oklahoma Department of Environmental Quality resulting in a compliance date of April 16, 2016 for OG&E. To comply with this rule, OG&E is currently planning to utilize activated carbon injection for the removal of mercury at each of its five coal-fired units, the capital costs of which are estimated to be approximately $20 million over a three year period and are included in the capital expenditures table in "Future Capital Requirements and Financing Activities" above. OG&E continues to review whether additional controls such as dry sorbent injection are needed for compliance with MATS. Current capital costs for installing the necessary control equipment for dry sorbent injection are estimated to be approximately $45 million over a three year period, but due to the uncertainty as to whether or not dry sorbent injection is necessary, such costs are not included in the capital expenditures table in "Future Capital Requirements and Financing Activities" above. OG&E is evaluating the results of field testing to finalize its plans and cost estimates. The final MATS rule has been appealed by several parties. OG&E is not a party to the appeals and cannot predict the outcome of any such appeals.

Federal Clean Air Act New Source Review Litigation

As previously reported, in July 2008, OG&E received a request for information from the EPA regarding Federal Clean Air Act compliance at OG&E's Muskogee and Sooner generating plants. In recent years, the EPA has issued similar requests to numerous other electric utilities seeking to determine whether various maintenance, repair and replacement projects should have required permits under the Federal Clean Air Act's new source review process. In January 2012, OG&E received a supplemental request for an update of the previously provided information and for some additional information not previously requested. On May 1, 2012, OG&E responded to the EPA's supplemental request for information. On April 26, 2011, the EPA issued a notice of violation alleging that 13 projects occurred at OG&E's Muskogee and Sooner generating plants between 1993 and 2006 without the required new source review permits. The notice of violation also alleges that OG&E's visible emissions at its Muskogee and Sooner generating plants are not in accordance with applicable new source performance standards.

In March 2013, the DOJ informed OG&E that it was prepared to initiate enforcement litigation concerning the matters identified in the notice of violation. OG&E subsequently met with EPA and DOJ representatives regarding the notice of violation and proposals for resolving the matter without litigation. On July 8, 2013, the United States, at the request of the EPA, filed a complaint for declaratory relief against OG&E in United States District Court for the Western District of Oklahoma (Case No. CIV-13-690-D) alleging that OG&E did not follow the Federal Clean Air Act procedures for projecting emission increases attributable to eight projects that occurred between 2003 and 2006. This complaint seeks to have OG&E submit a new assessment of whether the projects were likely to result in a significant emissions increase. The Sierra Club has intervened in this proceeding and has asserted claims for declaratory relief that are similar to those requested by the United States. OG&E expects to vigorously defend against these claims, but OG&E cannot predict the outcome of such litigation. On August 12, 2013, the Sierra Club filed a complaint against OG&E in the United States District Court for the Eastern District of Oklahoma (Case No. 13-CV-00356) alleging that OG&E modifications made at Unit 6 of the Muskogee generating plant in 2008 were made without obtaining a prevention of significant deterioration permit and that the plant has exceeded emissions limits for opacity and particulate matter. The Sierra Club seeks a permanent injunction preventing OG&E from operating the Muskogee generating plant. At this time, OG&E continues to believe that it has acted in compliance with the Federal Clean Air Act.

If OG&E does not prevail in these proceedings and if a new assessment of the projects were to conclude that they caused a significant emissions increase, the EPA and the Sierra Club could seek to require OG&E to install additional pollution control equipment, including scrubbers, baghouses and selective catalytic reduction systems with capital costs in excess of $1.0 billion and pay fines and significant penalties as a result of the allegations in the notice of violation. Section 113 of the Federal Clean Air Act (along with the Federal Civil Penalties Inflation Adjustment Act of 1996) provides for civil penalties as much as $37,500 per day for each violation. The cost of any required pollution control equipment could also be significant. OG&E cannot predict at this time whether it will be legally required to incur any of these costs.

National Ambient Air Quality Standards

The EPA is required to set NAAQS for certain pollutants considered to be harmful to public health or the environment. The Clean Air Act requires the EPA to review each NAAQS every five years. As a result of these reviews, the EPA periodically has taken action to adopt more stringent NAAQS for those pollutants. If any areas of Oklahoma were to be designated as not attaining the NAAQS for a particular pollutant, the Company could be required to install additional emission controls on its facilities to help the state achieve attainment with the NAAQS. As of the end of 2013, no areas of Oklahoma had been designated as nonattainment for pollutants that are likely to affect the Company's operations. Several processes are under way to designate areas in Oklahoma as attaining or not attaining revised NAAQS. The Company is monitoring those processes and their possible impact on its operations but, at this time, cannot determine with any certainty whether they will cause a material impact to the Company's financial results.

Acid Rain Program

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

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

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

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

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

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

Climate Change and Greenhouse Gas Emissions

There is continuing discussion and evaluation of possible global climate change in certain regulatory and legislative arenas. The focus is generally on emissions of greenhouse gases, including carbon dioxide, sulfur hexafluoride and methane, and whether these emissions are contributing to the warming of the Earth's atmosphere. There are various international agreements that restrict greenhouse gas emissions, but none of them have a binding effect on sources located in the United States. The U.S. Congress has not passed legislation to reduce emissions of greenhouse gases and the future prospects for any such legislation are uncertain, but the EPA believes it has existing authority under the Clean Air Act to regulate greenhouse gas emissions from stationary sources. Several states have passed laws, adopted regulations or undertaken regulatory initiatives to reduce the emission of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Oklahoma and Arkansas are not among them. If legislation or regulations are passed at the Federal or state levels in the future requiring mandatory reductions of carbon dioxide and other greenhouse gases on the Company's facilities, this could result in significant additional compliance costs that would affect the Company’s future financial position, results of operations and cash flows if such costs are not recovered through regulated rates.

In 2009, the EPA adopted a comprehensive national system for reporting emissions of carbon dioxide and other greenhouse gases produced by major sources in the United States. The reporting requirements apply to large direct emitters of greenhouse gases with emissions equal to or greater than a threshold of 25,000 metric tons per year, which includes certain OG&E facilities. OG&E also reports quarterly its carbon dioxide emissions from generating units subject to the Federal Acid Rain Program. OG&E has submitted the reports required by the applicable reporting rules.

Following from the Supreme Court's interpretation of the Clean Air Act's applicability to greenhouse gases in Massachusetts v. EPA, the EPA has proposed regulations for new power plants. In 2010, the EPA also issued a final rule that makes certain existing sources subject to permitting requirements for greenhouse gas emissions. This rule requires sources that emit greater than 100,000 tons per year of greenhouse gases to obtain a permit for those emissions, even if they are not otherwise required to obtain a new or modified permit. Such sources that undergo construction or modification may have to install best available control technology to control greenhouse gas emissions. Although these rules currently do not have a material impact on the Company's existing facilities, they ultimately could result in significant changes to the Company's operations, significant capital expenditures by the Company and a significant increase in the Company's cost of conducting business. In October 2013, the U.S. Supreme Court granted certiorari to review EPA's greenhouse gas regulations, including the Tailoring Rule which limits the sources subject to greenhouse gas permitting requirements to the largest fossil-fueled power plants. It is conceivable that the Court could invalidate EPA's prevention of significant deterioration and Title V Tailoring Rule, but still leave power plants subject to anticipated new and existing source performance standards for greenhouse gas emissions described below.

In January 2014, the EPA issued new proposed New Source Performance Standards that specify permissible levels of greenhouse gas emissions from newly-constructed fossil fuel-fired electric generating units. The proposed New Source Performance Standards sets separate standards for natural gas combined cycle units and coal-fired generating units. As directed by President Obama's June 25, 2013, Climate Action Plan, the EPA also announced plans to establish, pursuant to Section 111(d) of the Clean Air Act, carbon dioxide emissions standards for existing fossil fuel fired electric generating units. EPA plans to publish the proposed standards for existing units by June 1, 2014, and finalize those guidelines by June 1, 2015. States must then submit their individual plans for reducing power plants' greenhouse gas emissions to EPA by June 30, 2016.

The Company is continuing to review and evaluate available options for reducing, avoiding, offsetting or sequestering its greenhouse gas emissions.

The Company also seeks to utilize renewable energy sources that do not emit greenhouse gases. OG&E's service territory is in central Oklahoma and borders one of the nation's best wind resource areas. The Company has leveraged its advantageous geographic position to develop renewable energy resources and transmission to deliver the renewable energy. The SPP has begun to authorize the construction of transmission lines capable of bringing renewable energy out of the wind resource area in western Oklahoma, the Texas Panhandle and western Kansas to load centers by planning for more transmission to be built in the area. In addition to significantly increasing overall system reliability, these new transmission resources should provide greater access to additional wind resources that are currently constrained due to existing transmission delivery limitations.

Endangered Species

Certain Federal laws, including the Bald and Golden Eagle Protection Act, the Migratory Bird Treaty Act and the Endangered Species Act, provide special protection to certain designated species. These laws and any state equivalents provide for significant civil and criminal penalties for unpermitted activities that result in harm to or harassment of certain protected animals and plants, including damage to their habitats. If such species are located in an area in which the Company conducts operations, or if additional species in those areas become subject to protection, the Company’s operations and development projects, particularly transmission or wind projects, could be restricted or delayed, or the Company could be required to implement expensive mitigation measures. The U.S. Fish and Wildlife Service announced a proposed rule to list the lesser prairie chicken as threatened on November 30, 2012. A final decision regarding listing is anticipated to be completed by March 30, 2014. Although the lesser prairie chicken and its habitat are located in potential development areas of the Company, the impact of a final decision to list this species as threatened cannot be determined at this time.

Waste

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

For OG&E, these laws impose strict requirements on waste generators regarding their treatment, storage and disposal of waste. OG&E routinely generates small quantities of hazardous waste throughout its system. These wastes are treated, stored and disposed at facilities that are permitted to manage them.

In June 2010, the EPA proposed new rules under Federal Resource Conservation and Recovery Act of 1976 that could make the management of coal ash more costly. The extent to which the EPA intends to regulate coal ash is uncertain. The EPA continues to consider numerous comments received on the proposal. On January 29, 2014, the EPA entered into a consent decree directing them, by December 19, 2014, to sign for publication in the Federal Register a notice taking final action on the EPA's proposed Subtitle D option for coal ash which set performance standards for waste management, to be administered by the states.

The Company has sought and will continue to seek pollution prevention opportunities and to evaluate the effectiveness of its waste reduction, reuse and recycling efforts. In 2013, the Company obtained refunds of $3.5 million from the recycling of scrap metal, salvaged transformers and used transformer oil. This figure does not include the additional savings gained through the reduction and/or avoidance of disposal costs and the reduction in material purchases due to the reuse of existing materials. Similar savings are anticipated in future years.

Water

OG&E's operations are subject to the Federal Clean Water Act, and analogous state laws and regulations. These laws and regulations impose detailed requirements and strict controls regarding the discharge of pollutants into state and Federal waters. The discharge of pollutants, including discharges resulting from a spill or leak, is prohibited unless authorized by a permit or other agency approval. The Federal Clean Water Act and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. Existing cooling water intake structures are regulated under the Federal Clean Water Act to minimize their impact on the environment.

With respect to cooling water intake structures, Section 316(b) of the Federal Clean Water Act requires that their location, design, construction and capacity reflect the best available technology for minimizing their adverse environmental impact via the impingement and entrainment of aquatic organisms. In March 2011, the EPA proposed rules to implement Section 316(b). Recently, the EPA announced that it will issue a final rule by April 17, 2014. In the interim, the state of Oklahoma requires OG&E to implement best management practices related to the operation and maintenance of its existing cooling water intake structures as a condition of renewing its discharge permits. Once the EPA promulgates the final rules, OG&E may incur additional capital and/or operating costs to comply with them. The costs of complying with the final water intake standards are not currently determinable, but could be significant.

Site Remediation

The Comprehensive Environmental Response, Compensation and Liability Act of 1980 and comparable state laws impose liability, without regard to the legality of the original conduct, on certain classes of persons responsible for the release of hazardous substances into the environment. Because OG&E utilizes various products and generate wastes that are considered hazardous substances for purposes of the Comprehensive Environmental Response, Compensation and Liability Act of 1980, OG&E could be subject to liability for the costs of cleaning up and restoring sites where those substances have been released to the environment. At this time, it is not anticipated that any associated liability will cause a significant impact to OG&E or Enogex.

For a further discussion regarding contingencies relating to environmental laws and regulations, see Note 15 of Notes to Consolidated Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk.

Market risks are, in most cases, risks that are actively traded in a marketplace and have been well studied in regards to quantification. Market risks include, but are not limited to, changes in interest rates and commodity prices. The Company's exposure to changes in interest rates relates primarily to short-term variable-rate debt and commercial paper. The Company is exposed to commodity prices in its operations.

Risk Oversight Committee

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

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

Risk Policies

Management utilizes risk policies to control the amount of market risk exposure. These policies are designed to provide the Audit Committee of the Company's Board of Directors and senior executives of the Company with confidence that the risks taken on by the Company's business activities are in accordance with their expectations for financial returns and that the approved policies and controls related to market risk management are being followed.

Interest Rate Risk

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

The fair value of the Company's long-term debt is based on quoted market prices and estimates of current rates available for similar issues with similar maturities or by calculating the net present value of the monthly payments discounted by the Company's current borrowing rate. The following table shows the Company's long-term debt maturities and the weighted-average interest rates by maturity date.

Year ended December 31 *(Dollars in millions)*	2014	2015	2016	2017	2018	Thereafter	Total	12/31/13 Fair Value
Fixed-rate debt (A)								
Principal amount	$ 100.2	$ 0.2	$ 110.2	$ 125.1	$ 250.1	$ 1,684.5	$ 2,270.3	$ 2,517.2
Weighted-average interest rate	5.00%	2.95%	5.15%	6.50%	6.35%	6.03%	6.00%	
Variable-rate debt (B)								
Principal amount	$ —	$ —	$ —	$ —	$ —	$ 135.4	$ 135.4	$ 135.4
Weighted-average interest rate	—%	—%	—%	—%	—%	0.13%	0.13%	

(A) Prior to or when these debt obligations mature, the Company may refinance all or a portion of such debt at then-existing market interest rates which may be more or less than the interest rates on the maturing debt.

(B) A hypothetical change of 100 basis points in the underlying variable interest rate incurred by the Company would change interest expense by $1.4 million annually.

Item 8. Financial Statements and Supplementary Data.

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

Year ended December 31 *(In millions except per share data)*	**2013**	2012	2011
OPERATING REVENUES			
Electric Utility operating revenues	**$ 2,259.7**	$ 2,128.7	$ 2,211.5
Natural Gas Midstream Operations operating revenues (Note 1)	**608.0**	1,542.5	1,704.4
Total operating revenues	**2,867.7**	3,671.2	3,915.9
COST OF SALES			
Electric Utility Fuel and purchased power	**950.0**	831.4	966.0
Natural Gas Midstream Operations Cost of sales and fuel (Note 1)	**478.9**	1,087.3	1,311.9
Total cost of sales	**1,428.9**	1,918.7	2,277.9
OPERATING EXPENSES			
Other operation and maintenance	**489.2**	601.5	581.2
Depreciation and amortization	**297.3**	371.0	307.1
Impairment of assets	**—**	0.4	6.3
Gain on insurance proceeds	**—**	(7.5)	(3.0)
Taxes other than income	**98.8**	110.2	99.7
Total operating expenses	**885.3**	1,075.6	991.3
OPERATING INCOME	**553.5**	676.9	646.7
OTHER INCOME (EXPENSE)			
Equity in earnings of unconsolidated affiliates (Note 1)	**101.9**	—	—
Allowance for equity funds used during construction	**6.6**	6.2	20.4
Other income	**31.8**	17.6	19.8
Other expense	**(22.2)**	(16.5)	(21.7)
Net other income (expense)	**118.1**	7.3	18.5
INTEREST EXPENSE			
Interest on long-term debt	**145.6**	158.9	146.1
Allowance for borrowed funds used during construction	**(3.4)**	(3.5)	(10.4)
Interest on short-term debt and other interest charges	**5.3**	8.7	5.2
Interest expense	**147.5**	164.1	140.9
INCOME BEFORE TAXES	**524.1**	520.1	524.3
INCOME TAX EXPENSE	**130.3**	135.1	160.7
NET INCOME	**393.8**	385.0	363.6
Less: Net income attributable to noncontrolling interests	**6.2**	30.0	20.7
NET INCOME ATTRIBUTABLE TO OGE ENERGY	**$ 387.6**	$ 355.0	$ 342.9
BASIC AVERAGE COMMON SHARES OUTSTANDING	**198.2**	197.1	195.8
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**199.4**	198.1	198.5
BASIC EARNINGS PER AVERAGE COMMON SHARE ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS	**$ 1.96**	$ 1.80	$ 1.75
DILUTED EARNINGS PER AVERAGE COMMON SHARES ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS	**$ 1.94**	$ 1.79	$ 1.73
DIVIDENDS DECLARED PER COMMON SHARE	**$ 0.8513**	$ 0.7975	$ 0.7588

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year ended December 31 *(In millions)*	**2013**	2012	2011
Net income	**$ 393.8**	$ 385.0	$ 363.6
Other comprehensive income (loss), net of tax			
Pension Plan and Restoration of Retirement Income Plan:			
Amortization of deferred net loss, net of tax of $2.4, $1.7 and $1.4, respectively	**3.7**	3.0	2.5
Net gain (loss) arising during the period, net of tax of $7.8, ($5.6) and ($6.7), respectively	**12.4**	(10.2)	(13.5)
Amortization of prior service cost, net of tax of $0, $0.2 and $0.2, respectively	**—**	0.2	0.4
Settlement cost, net of tax of $1.9, $0 and $0, respectively	**3.0**	—	—
Postretirement Benefit Plans:			
Amortization of deferred net loss, net of tax of $1.3, ($1.1) and ($1.6), respectively	**2.0**	2.0	1.8
Net loss arising during the period, net of tax of $4.4, ($1.1) and ($3.1), respectively	**6.9**	(2.3)	(3.6)
Amortization of deferred net transition obligation, net of tax of $0, $0.1 and $0.1, respectively	**—**	0.1	0.2
Amortization of prior service cost, net of tax of $(1.1), ($1.0) and ($1.6), respectively	**(1.8)**	(1.8)	(1.8)
Prior service credit arising during the period, net of tax of $0, $0, and $9.5, respectively	**—**	—	10.8
Deferred commodity contracts hedging (gains) losses reclassified in net income, net of tax of $0.4, ($1.6) and $12.6, respectively	**0.6**	(3.6)	27.6
Deferred commodity contracts hedging gains (losses), net of tax of $0, $0.1 and ($1.7), respectively	**—**	0.4	(4.8)
Amortization of deferred interest rate swap hedging losses, net of tax of $0.1, $0.2, and $0.2, respectively	**0.3**	0.2	0.3
Other comprehensive income (loss), net of tax	**27.1**	(12.0)	19.9
Comprehensive income (loss)	**420.9**	373.0	383.5
Less: Comprehensive income attributable to noncontrolling interest for sale of equity investment	**—**	(0.5)	(3.2)
Less: Comprehensive income attributable to noncontrolling interests	**6.3**	27.0	24.2
Less: Deconsolidation of Enogex Holdings	**6.1**	—	—
Total comprehensive income attributable to OGE Energy	**$ 408.5**	$ 346.5	$ 362.5

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CASH FLOWS

Year ended December 31 *(In millions)*	**2013**	2012	2011
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	**$ 393.8**	$ 385.0	$ 363.6
Adjustments to reconcile net income to net cash provided from operating activities			
Depreciation and amortization	**298.6**	374.8	307.7
Impairment of assets	**—**	0.4	6.3
Deferred income taxes and investment tax credits, net	**125.9**	143.7	166.0
Equity in earnings of unconsolidated affiliates	**(101.9)**	—	—
Distributions from unconsolidated affiliates	**51.7**	—	—
Allowance for equity funds used during construction	**(6.6)**	(6.2)	(20.4)
(Gain) loss on disposition and abandonment of assets	**(8.6)**	4.2	(2.7)
Gain on insurance proceeds	**—**	(7.5)	(3.0)
Stock-based compensation	**(3.5)**	(2.6)	7.8
Regulatory assets	**26.8**	20.3	14.0
Regulatory liabilities	**(32.5)**	(14.8)	(1.9)
Other assets	**1.3**	(6.9)	(7.6)
Other liabilities	**(7.0)**	(14.3)	(37.4)
Change in certain current assets and liabilities			
Accounts receivable, net	**(34.0)**	27.1	(48.0)
Accrued unbilled revenues	**(1.3)**	1.9	(2.5)
Income taxes receivable	**1.6**	1.1	(3.6)
Fuel, materials and supplies inventories	**5.1**	13.7	54.2
Fuel clause under recoveries	**(26.2)**	1.8	(0.8)
Other current assets	**(4.5)**	(8.6)	(8.2)
Accounts payable	**56.9**	25.1	34.5
Accounts payable - unconsolidated affiliates	**3.7**	—	—
Fuel clause over recoveries	**(108.8)**	101.5	(22.2)
Other current liabilities	**(7.3)**	6.4	38.1
Net Cash Provided from Operating Activities	**623.2**	1,046.1	833.9
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures (less allowance for equity funds used during construction)	**(990.6)**	(1,150.6)	(1,270.4)
Investment in unconsolidated affiliates	**(2.7)**	—	—
Acquisition of gathering assets	**—**	(78.6)	(200.4)
Proceeds from insurance	**—**	7.6	7.4
Reimbursement of capital expenditures	**—**	27.5	49.6
Proceeds from sale of assets	**36.3**	1.5	18.0
Net Cash Used in Investing Activities	**(957.0)**	**(1,192.6)**	**(1,395.8)**
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from long-term debt	**247.4**	250.0	246.3
Changes in advances with unconsolidated affiliates	**129.6**	—	—
Contributions from noncontrolling interest partners	**107.0**	46.2	216.4
Issuance of common stock	**14.2**	14.3	14.8
Increase in short-term debt	**8.7**	153.8	132.1
Repayment of line of credit	**—**	(150.0)	(25.0)
Proceeds from line of credit	**—**	—	150.0
Purchase of treasury stock	**—**	(3.4)	(6.2)
Payment of long-term debt	**(0.1)**	(0.1)	—
Distributions to noncontrolling interest partners	**(2.5)**	(12.6)	(17.4)
Dividends paid on common stock	**(165.5)**	(154.5)	(146.8)
Net Cash Provided from Financing Activities	**338.8**	143.7	564.2
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	**5.0**	(2.8)	2.3
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**1.8**	4.6	2.3
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 6.8**	$ 1.8	$ 4.6

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

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS

December 31 *(In millions)*	**2013**	2012
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 6.8**	$ 1.8
Accounts receivable, less reserve of $1.9 and $2.6, respectively	**179.4**	295.3
Accounts receivable - unconsolidated affiliates	**12.4**	—
Accrued unbilled revenues	**58.7**	57.4
Income taxes receivable	**5.6**	7.2
Fuel inventories	**74.4**	93.3
Materials and supplies, at average cost	**80.7**	80.9
Deferred income taxes	**215.8**	187.7
Fuel clause under recoveries	**26.2**	—
Assets held for sale	**—**	25.5
Other	**34.6**	45.1
Total current assets	**694.6**	794.2
OTHER PROPERTY AND INVESTMENTS		
Investment in unconsolidated affiliates	**1,298.8**	—
Other	**61.0**	52.2
Total other property and investments	**1,359.8**	52.2
PROPERTY, PLANT AND EQUIPMENT		
In service	**9,183.1**	11,504.4
Construction work in progress	**468.5**	387.5
Total property, plant and equipment	**9,651.6**	11,891.9
Less accumulated depreciation	**2,978.8**	3,547.1
Net property, plant and equipment	**6,672.8**	8,344.8
DEFERRED CHARGES AND OTHER ASSETS		
Regulatory assets	**379.1**	510.6
Intangible assets, net	**—**	127.4
Goodwill	**—**	39.4
Other	**28.4**	53.6
Total deferred charges and other assets	**407.5**	731.0
TOTAL ASSETS	**$ 9,134.7**	$ 9,922.2

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

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS (Continued)

December 31 *(In millions)*	**2013**	2012
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ 439.6**	$ 430.9
Accounts payable	**251.0**	396.7
Dividends payable	**44.7**	41.2
Customer deposits	**70.9**	70.3
Accrued taxes	**39.9**	48.1
Accrued interest	**43.4**	55.0
Accrued compensation	**56.9**	55.2
Long-term debt due within one year	**100.0**	—
Fuel clause over recoveries	**0.4**	109.2
Other	**47.0**	69.8
Total current liabilities	**1,093.8**	1,276.4
LONG-TERM DEBT	**2,300.1**	2,848.6
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued benefit obligations	**241.5**	399.8
Deferred income taxes	**2,125.3**	1,948.8
Deferred investment tax credits	**1.9**	3.9
Regulatory liabilities	**234.2**	245.1
Deferred revenues	**0.4**	37.7
Other	**100.4**	89.5
Total deferred credits and other liabilities	**2,703.7**	2,724.8
Total liabilities	**6,097.6**	6,849.8
COMMITMENTS AND CONTINGENCIES (NOTE 15)		
STOCKHOLDERS' EQUITY		
Common stockholders' equity	**1,073.6**	1,047.4
Retained earnings	**1,991.7**	1,772.4
Accumulated other comprehensive loss, net of tax	**(28.2)**	(49.1)
Treasury stock, at cost	**—**	(3.5)
Total OGE Energy stockholders' equity	**3,037.1**	2,767.2
Noncontrolling interests	**—**	305.2
Total stockholders' equity	**3,037.1**	3,072.4
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 9,134.7**	$ 9,922.2

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 *(In millions)*			**2013**	2012
STOCKHOLDERS' EQUITY				
Common stock, par value $0.01 per share; authorized 450.0 shares; and outstanding 198.5 and 197.5 shares, respectively			**$ 2.0**	$ 1.0
Premium on common stock			**1,071.6**	1,046.4
Retained earnings			**1,991.7**	1,772.4
Accumulated other comprehensive loss, net of tax			**(28.2)**	(49.1)
Treasury stock, at cost, 0.1 and 0.1 shares, respectively			**—**	(3.5)
Total OGE Energy stockholders' equity			**3,037.1**	2,767.2
Noncontrolling interest			**—**	305.2
Total stockholders' equity			**3,037.1**	3,072.4
LONG-TERM DEBT				
	SERIES	DUE DATE		
	Senior Notes - OGE Energy			
	5.00%	Senior Notes, Series Due November 15, 2014	**100.0**	100.0
	Unamortized discount		**(0.1)**	(0.1)
	Senior Notes - OG&E			
	5.15%	Senior Notes, Series Due January 15, 2016	**110.0**	110.0
	6.50%	Senior Notes, Series Due July 15, 2017	**125.0**	125.0
	6.35%	Senior Notes, Series Due September 1, 2018	**250.0**	250.0
	8.25%	Senior Notes, Series Due January 15, 2019	**250.0**	250.0
	6.65%	Senior Notes, Series Due July 15, 2027	**125.0**	125.0
	6.50%	Senior Notes, Series Due April 15, 2028	**100.0**	100.0
	6.50%	Senior Notes, Series Due August 1, 2034	**140.0**	140.0
	5.75%	Senior Notes, Series Due January 15, 2036	**110.0**	110.0
	6.45%	Senior Notes, Series Due February 1, 2038	**200.0**	200.0
	5.85%	Senior Notes, Series Due June 1, 2040	**250.0**	250.0
	5.25%	Senior Notes, Series Due May 15, 2041	**250.0**	250.0
	3.90%	Senior Notes, Series Due May 1, 2043	**250.0**	—
	3.70%	Tinker Debt, Due August 31, 2062	**10.3**	10.7
	Other Bonds - OG&E			
	0.18% - 0.34%	Garfield Industrial Authority, January 1, 2025	**47.0**	47.0
	0.10% - 0.39%	Muskogee Industrial Authority, January 1, 2025	**32.4**	32.4
	0.10% - 0.30%	Muskogee Industrial Authority, June 1, 2027	**56.0**	56.0
	Unamortized discount		**(5.5)**	(5.8)
	Enogex LLC			
	6.875%	Senior Notes, Series Due July 15, 2014	**N/A**	200.0
	1.72%	Enogex LLC Term Loan Agreement, Due August 2, 2015	**N/A**	250.0
	6.25%	Senior Notes, Series Due March 15, 2020	**N/A**	250.0
	Unamortized discount		**N/A**	(1.6)
Total long-term debt			**2,400.1**	2,848.6
Less long-term debt due within one year			**(100.0)**	—
Total long-term debt (excluding debt due within one year)			**2,300.1**	2,848.6
Total Capitalization			**$ 5,437.2**	$ 5,921.0

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

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

(In millions)	Common Stock	Premium on Common Stock	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Treasury Stock	Total
Balance at December 31, 2010	$ 1.0	$ 968.2	$ 1,380.6	$ (60.2)	$ 110.4	$ —	$ 2,400.0
Net income	—	—	342.9	—	20.7	—	363.6
Other comprehensive income (loss), net of tax	—	—	—	19.6	0.3	—	19.9
Dividends declared on common stock	—	—	(148.7)	—	—	—	(148.7)
Issuance of common stock	—	14.8	—	—	—	—	14.8
Stock-based compensation and other	—	5.8	—	—	—	—	5.8
Contributions from noncontrolling interest partners	—	74.4	—	—	142.0	—	216.4
Distributions to noncontrolling interest partners	—	—	—	—	(17.4)	—	(17.4)
Deferred income taxes attributable to contributions from noncontrolling interest partners	—	(28.9)	—	—	—	—	(28.9)
Purchase of treasury stock	—	—	—	—	—	(6.2)	(6.2)
Balance at December 31, 2011	$ 1.0	$ 1,034.3	$ 1,574.8	$ (40.6)	$ 256.0	$ (6.2)	$ 2,819.3
Net income	—	—	355.0	—	30.0	—	385.0
Other comprehensive income (loss), net of tax	—	—	—	(8.5)	(3.5)	—	(12.0)
Dividends declared on common stock	—	—	(157.4)	—	—	—	(157.4)
Issuance of common stock	—	14.3	—	—	—	—	14.3
Stock-based compensation and other	—	(8.7)	—	—	(0.2)	6.1	(2.8)
Contributions from noncontrolling interest partners	—	10.7	—	—	35.5	—	46.2
Distributions to noncontrolling interest partners	—	—	—	—	(12.6)	—	(12.6)
Deferred income taxes attributable to contributions from noncontrolling interest partners	—	(4.2)	—	—	—	—	(4.2)
Purchase of treasury stock	—	—	—	—	—	(3.4)	(3.4)
Balance at December 31, 2012	$ 1.0	$ 1,046.4	$ 1,772.4	$ (49.1)	$ 305.2	$ (3.5)	$ 3,072.4
Net income	**—**	**—**	**387.6**	**—**	**6.2**	**—**	**393.8**
Other comprehensive income (loss), net of tax	**—**	**—**	**—**	**27.0**	**0.1**	**—**	**27.1**
Dividends declared on common stock	**—**	**—**	**(168.8)**	**—**	**—**	**—**	**(168.8)**
Issuance of common stock	**—**	**14.2**	**—**	**—**	**—**	**—**	**14.2**
Stock-based compensation and other	**—**	**(1.8)**	**—**	**—**	**(0.8)**	**3.5**	**0.9**
Contributions from noncontrolling interest partners	**—**	**22.5**	**—**	**—**	**84.5**	**—**	**107.0**
Distributions to noncontrolling interest partners	**—**	**—**	**—**	**—**	**(2.5)**	**—**	**(2.5)**
Deconsolidation of Enogex Holdings	**—**	**—**	**0.5**	**(6.1)**	**(392.7)**	**—**	**(398.3)**
Deferred income taxes attributable to contributions from noncontrolling interest partners	**—**	**(8.7)**	**—**	**—**	**—**	**—**	**(8.7)**
2-for-1 forward stock split	**1.0**	**(1.0)**	**—**	**—**	**—**	**—**	**—**
Balance at December 31, 2013	**$ 2.0**	**$ 1,071.6**	**$ 1,991.7**	**$ (28.2)**	**$ —**	**$ —**	**$ 3,037.1**

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

OGE ENERGY CORP.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Organization

The Company is an energy and energy services provider offering physical delivery and related services for both electricity and natural gas primarily in the south central United States. The Company conducts these activities through two business segments: (i) electric utility and (ii) natural gas midstream operations. For a discussion of the change in the Company’s business segments due to the formation of Enable, see Note 14. For periods prior to May 1, 2013, the Company consolidated Enogex Holdings in its Condensed Consolidated Financial Statements. All significant intercompany transactions have been eliminated in consolidation.

Effective May 1, 2013, OGE Energy, the ArcLight group and CenterPoint Energy, Inc., formed Enable Midstream Partners, LP to own and operate the midstream businesses of OGE Energy and CenterPoint. In the formation transaction, OGE Energy and ArcLight group contributed Enogex LLC to Enable and the Company deconsolidated its previously held investment in Enogex Holdings and acquired an equity interest in Enable. The Company determined that its contribution of Enogex LLC to Enable met the requirements of being in substance real estate and was recorded at historical cost. The general partner of Enable is equally controlled by CenterPoint and OGE Energy, who each have 50 percent of the management rights. Based on the 50/50 management ownership, with neither company having control, effective May 1, 2013, OGE Energy began accounting for its interest in Enable using the equity method of accounting. At December 31, 2013, OGE Energy, through its wholly owned subsidiary OGE Holdings, holds 28.5 percent of the limited partner interests in Enable. OGE Energy also owns a 60 percent interest in any incentive distribution rights in Enable. Incentive distribution rights are expected to entitle the holder to increasing percentages, up to a maximum of 50 percent, of the cash distributed by Enable in excess of the target quarterly distributions to be set in connection with Enable’s initial public offering. On November 26, 2013, Enable filed a registration statement on Form S-1 related to the proposed initial public offering of limited partnership interests that will have the effect of making Enable a publicly traded master limited partnership.

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.

The natural gas midstream operations segment consists of the Company's investment in Enable. Enable is engaged in the business of gathering, processing, transporting and storing natural gas. Enable's natural gas gathering and processing assets are strategically located in four states and serve natural gas production from shale developments in the Anadarko, Arkoma and Ark-La-Tex basins. Enable also owns an emerging crude oil gathering business in the Bakken shale formation that commenced initial operations in November 2013. Enable is continuing to construct additional crude oil gathering capacity in this area. Enable's natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

As discussed below, the Company completed a 2-for-1 stock split of the Company's common stock effective July 1, 2013. All share and per share amounts within this Form 10-K reflect the effects of the stock split.

OGE Energy charges operating costs to its subsidiaries and unconsolidated affiliate based on several factors. Operating costs directly related to specific subsidiaries or unconsolidated affiliate are assigned to those subsidiaries or unconsolidated affiliate. Where more than one subsidiary or unconsolidated affiliate benefits from certain expenditures, the costs are shared between those subsidiaries and unconsolidated affiliate receiving the benefits. Operating costs incurred for the benefit of all subsidiaries and unconsolidated affiliate are allocated among the subsidiaries and unconsolidated affiliate, either as overhead based primarily on labor costs or using the "Distrigas" method. The Distrigas method is a three-factor formula that uses an equal weighting of payroll, net operating revenues and gross property, plant and equipment. OGE Energy adopted the Distrigas method in January 1996 as a result of a recommendation by the OCC Staff. OGE Energy believes this method provides a reasonable basis for allocating common expenses.

Basis of Presentation

In the opinion of management, all adjustments necessary to fairly present the consolidated financial position of the Company at December 31, 2013 and 2012 and the results of its operations and cash flows for the years ended December 31, 2013, 2012 and 2011, have been included and are of a normal recurring nature except as otherwise disclosed.

Accounting Records

The accounting records of OG&E are maintained in accordance with the Uniform System of Accounts prescribed by the FERC and adopted by the OCC and the APSC. Additionally, OG&E, as a regulated utility, is subject to accounting principles for certain types of rate-regulated activities, which provide that certain actual or anticipated costs that would otherwise be charged to expense can be deferred as regulatory assets, based on the expected recovery from customers in future rates. Likewise, certain actual or anticipated credits that would otherwise reduce expense can be deferred as regulatory liabilities, based on the expected flowback to customers in future rates. Management's expected recovery of deferred costs and flowback of deferred credits generally results from specific decisions by regulators granting such ratemaking treatment.

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

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

December 31 *(In millions)*	**2013**	2012
Regulatory Assets		
Current		
Fuel clause under recoveries	**$ 26.2**	$ —
Oklahoma demand program rider under recovery (A)	**10.6**	9.2
Crossroads wind farm rider under recovery (A)	**4.7**	14.9
Other (A)	**7.3**	2.9
Total Current Regulatory Assets	**$ 48.8**	**$ 27.0**
Non-Current		
Benefit obligations regulatory asset	**$ 227.4**	$ 370.6
Income taxes recoverable from customers, net	**56.5**	54.7
Smart Grid	**44.2**	42.8
Deferred storm expenses	**21.6**	12.7
Unamortized loss on reacquired debt	**11.8**	13.0
Pension tracker	**1.4**	—
Other	**16.2**	16.8
Total Non-Current Regulatory Assets	**$ 379.1**	$ 510.6
Regulatory Liabilities		
Current		
Smart Grid rider over recovery (B)	**$ 16.7**	$ 24.1
Fuel clause over recoveries	**0.4**	109.2
Other (B)	**3.1**	7.8
Total Current Regulatory Liabilities	**$ 20.2**	**$ 141.1**
Non-Current		
Accrued removal obligations, net	**$ 227.7**	$ 218.2
Deferred pension credits	**6.5**	17.7
Pension tracker	**—**	9.2
Total Non-Current Regulatory Liabilities	**$ 234.2**	$ 245.1

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

OG&E recovers a return on the capital expenditures along with operation and maintenance expense and depreciation expense related to the Crossroads wind farm through riders established by the OCC and APSC. OG&E began recovery in the fourth quarter of 2011 in Oklahoma and June of 2013 in Arkansas, and believes the rider will continue until new rates are implemented in OG&E's next general rate case in each jurisdiction.

OG&E recovers program costs related to the Demand and Energy Efficiency Program. An extension of the demand program rider was approved in December 2012, which allows for the recovery of demand program costs, lost revenues associated with certain achieved energy, demand savings and performance based incentives and the recovery of costs associated with research and development investments through December 2015.

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

The benefit obligations regulatory asset is comprised of expenses recorded which are probable of future recovery and that have not yet been recognized as components of net periodic benefit cost, including net loss, prior service cost and net transition obligation. These expenses are recorded as a regulatory asset as OG&E had historically recovered and currently recovers pension and postretirement benefit plan expense in its electric rates. If, in the future, the regulatory bodies indicate a change in policy related to the recovery of pension and postretirement benefit plan expenses, this could cause the benefit obligations regulatory asset balance to be reclassified to Accumulated other comprehensive income.

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

December 31 *(In millions)*	**2013**	2012
Pension Plan and Restoration of Retirement Income Plan		
Net loss	**$ 178.4**	$ 278.6
Prior service cost	**2.5**	4.5
Postretirement Benefit Plans		
Net loss	**79.9**	134.6
Prior service cost	**(33.4)**	(47.1)
Total	**$ 227.4**	$ 370.6

The following amounts in the benefit obligations regulatory asset at December 31, 2013 are expected to be recognized as components of net periodic benefit cost in 2014:

(In millions)	
Pension Plan and Restoration of Retirement Income Plan	
Net loss	**$ 11.4**
Prior service cost	**2.0**
Postretirement Benefit Plans	
Net loss	**11.0**
Prior service cost	**(13.7)**
Total	**$ 10.7**

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

OG&E recovers the cost of system-wide deployment of smart grid technology and implementing the smart grid pilot program, the incremental costs for web portal access, education and providing home energy reports and stranded costs associated with OG&E's existing meters. The costs recoverable from Oklahoma customers for system-wide deployment of smart grid technology and implementing the smart grid pilot program were capped at $366.4 million (inclusive of the U.S. Department of Energy grant award of $130.0 million) subject to an offset for any recovery of those costs from Arkansas customers. These amounts 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. Costs not included in the rider are the incremental costs for web portal access, education and home energy reports, which are capped at $6.9 million, and the stranded costs associated with OG&E's existing meters, which have been replaced by smart meters, which were accumulated during the smart grid deployment and have been included in the Smart Grid asset in the table above. These costs are expected to be recovered in base rates in OG&E's next general rate case.

OG&E defers annual Oklahoma storm-related operation and maintenance expenses in excess of $2.7 million and expenses any Oklahoma storm-related operation and maintenance expenses up to $2.7 million. OG&E will recover the deferred amounts over a five-year period ending in August 2017.

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

OG&E recovers specific amounts of pension and postretirement medical costs in rates approved in its Oklahoma rate cases. In accordance with approved orders, OG&E defers the difference between actual pension and postretirement medical expenses and the amount approved in its last Oklahoma rate case as a regulatory asset or regulatory liability. These amounts have been recorded in the Pension tracker in the regulatory assets and liabilities table above.

In September 2011, OG&E was allowed to include postretirement medical expenses in its pension tracker. In August 2012, OG&E was allowed to recover pension and postretirement medical expenses over a two-year period ending July 2014 which is included in Deferred pension credits in the regulatory assets and liabilities table above.

Accrued removal obligations represent asset retirement costs previously recovered from ratepayers for other than legal obligations.

Management continuously monitors the future recoverability of regulatory assets. When in management's judgment future recovery becomes impaired, the amount of the regulatory asset is adjusted, as appropriate. If 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.

Use of Estimates

In preparing the Consolidated Financial Statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and contingent liabilities at the date of the Consolidated Financial Statements and the reported amounts of revenues and expenses during the reporting period. Changes to these assumptions and estimates could have a material effect on the Company's Consolidated Financial Statements. However, the Company believes it has taken reasonable positions where assumptions and estimates are used in order to minimize the negative financial impact to the Company that could result if actual results vary from the assumptions and estimates. In management's opinion, the areas of the Company where the most significant judgment is exercised for all Company segments includes the determination of Pension Plan assumptions, impairment estimates of long-lived assets (including intangible assets), income taxes, contingency reserves, asset retirement obligations and assets and depreciable lives of property, plant and equipment. For the electric utility segment, the most significant judgment is also exercised in the existence of regulatory assets and liabilities and unbilled revenues.

Cash and Cash Equivalents

For purposes of the Consolidated Financial Statements, the Company considers all highly liquid debt instruments purchased with an original maturity of three months or less to be cash equivalents. These investments are carried at cost, which approximates fair value.

Allowance for Uncollectible Accounts Receivable

For OG&E, customer balances are generally written off if not collected within six months after the final billing date. The allowance for uncollectible accounts receivable for OG&E is calculated by multiplying the last six months of electric revenue by the provision rate. The provision rate is based on a 12-month historical average of actual balances written off. To the extent the historical collection rates are not representative of future collections, there could be an effect on the amount of uncollectible expense recognized. Also, a portion of the uncollectible provision related to fuel within the Oklahoma jurisdiction is being recovered through the fuel adjustment clause. The allowance for uncollectible accounts receivable was $1.9 million and $2.6 million at December 31, 2013 and 2012, respectively.

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

Fuel Inventories

Fuel inventories for the generation of electricity consist of coal, natural gas and oil. OG&E uses the weighted-average cost method of accounting for inventory that is physically added to or withdrawn from storage or stockpiles. The amount of fuel inventory was $74.4 million and $76.8 million at December 31, 2013 and 2012, respectively.

Gas Imbalances

Gas imbalances occur when the actual amounts of natural gas delivered from or received by OG&E differ from the amounts scheduled to be delivered or received. OG&E values all imbalances at an average of current market indices applicable to OG&E's operations, not to exceed net realizable value.

Property, Plant and Equipment

All property, plant and equipment is recorded at cost. Newly constructed plant is added to plant balances at cost which includes contracted services, direct labor, materials, overhead, transportation costs and the allowance for funds used during construction. Replacements of units of property are capitalized as plant. For assets that belong to a common plant account, the replaced plant is removed from plant balances and the cost of such property is charged to Accumulated Depreciation. For assets that do not belong to a common plant account, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance net of any salvage proceeds is recorded as a loss in the Consolidated Statements of Income as Other Expense. Repair and replacement of minor items of property are included in the Consolidated Statements of Income as Other Operation and Maintenance Expense.

The table below presents OG&E's ownership interest in the jointly-owned McClain Plant and the jointly-owned Redbud Plant, and, as disclosed below, only OG&E's ownership interest is reflected in the property, plant and equipment and accumulated depreciation balances in these tables. The owners of the remaining interests in the McClain Plant and the Redbud Plant are responsible for providing their own financing of capital expenditures. Also, only OG&E's proportionate interests of any direct expenses of the McClain Plant and the Redbud Plant such as fuel, maintenance expense and other operating expenses are included in the applicable financial statement captions in the Consolidated Statement of Income.

December 31, 2013 *(In millions)*	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
McClain Plant (A)	**77%**	**$ 180.8**	**$ 62.1**	**$ 118.7**
Redbud Plant (A)(B)	**51%**	**$ 498.9**	**$ 89.7**	**$ 409.2**

(A) Construction work in progress was $0.1 million and $39.5 million for the McClain and Redbud Plants, respectively.
(B) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $28.8 million.

December 31, 2012 *(In millions)*	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
McClain Plant (A)	**77%**	**$ 182.1**	**$ 56.3**	**$ 125.8**
Redbud Plant (A)(B)	**51%**	**$ 458.5**	**$ 69.5**	**$ 389.0**

(A) Construction work in progress was $0.1 million and $0.3 million for the McClain and Redbud Plants, respectively.
(B) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $23.3 million.

OGE Energy Consolidated

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

December 31, 2013 *(In millions)*	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
OGE Energy (holding company)			
Property, plant and equipment	**$ 152.4**	**$ 114.2**	**$ 38.2**
OGE Energy property, plant and equipment	**152.4**	**114.2**	**38.2**
OG&E			
Distribution assets	**3,403.8**	**1,028.2**	**2,375.6**
Electric generation assets (A)	**3,551.0**	**1,306.1**	**2,244.9**
Transmission assets (B)	**2,163.7**	**385.0**	**1,778.7**
Intangible plant	**50.5**	**27.1**	**23.4**
Other property and equipment	**330.2**	**118.2**	**212.0**
OG&E property, plant and equipment	**9,499.2**	**2,864.6**	**6,634.6**
Total property, plant and equipment	**$ 9,651.6**	**$ 2,978.8**	**$ 6,672.8**

(A) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $28.8 million.
(B) This amount includes a plant acquisition adjustment of $3.3 million and accumulated amortization of $0.3 million.

December 31, 2012 *(In millions)*	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
OGE Energy (holding company)			
Property, plant and equipment	$ 142.1	$ 103.2	$ 38.9
OGE Energy property, plant and equipment	142.1	103.2	38.9
OG&E			
Distribution assets	3,222.7	969.6	2,253.1
Electric generation assets (A)	3,446.6	1,242.4	2,204.2
Transmission assets (B)	1,712.6	359.8	1,352.8
Intangible plant	50.2	25.0	25.2
Other property and equipment	317.6	108.8	208.8
OG&E property, plant and equipment	8,749.7	2,705.6	6,044.1
Enogex			
Natural gas transportation and storage assets	988.6	292.7	695.9
Natural gas gathering and processing assets	2,011.5	445.6	1,565.9
Enogex property, plant and equipment	3,000.1	738.3	2,261.8
Total property, plant and equipment	$ 11,891.9	$ 3,547.1	$ 8,344.8

(A) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $23.3 million.
(B) This amount includes a plant acquisition adjustment of $3.3 million and accumulated amortization of $0.3 million.

The following table summarizes the Company's unamortized computer software costs.

December 31 *(In millions)*	**2013**	2012
OGE Energy (holding company)	**$ 7.2**	$ 11.6
OG&E	**16.8**	17.6
Enogex	**—**	3.9
Total	**$ 24.0**	$ 33.1

The following table summarizes the Company's amortization expense for computer software costs.

Year ended December 31 *(In millions)*	**2013**	2012	2011
OGE Energy (holding company)	**$ 6.4**	$ 6.8	$ 6.4
OG&E	**4.0**	4.2	1.8
Enogex	**0.8**	3.1	1.0
Total	**$ 11.2**	$ 14.1	$ 9.2

Intangible Assets

As a result of the formation of Enable on May 1, 2013 and the Company's deconsolidation of Enogex Holdings, the Company no longer has intangible assets.

OGE Holdings

The following table below summarizes OGE Holdings' intangible assets and related accumulated amortization at: December 31, 2012.

(In millions)	Total Intangible Assets	Accumulated Amortization	Net Intangible Assets
Customer Contract / Acreage Dedication	$ 141.9	$ 14.5	$ 127.4

In 2013, 2012 and 2011, amortization expense for intangible assets was $1.9 million, $9.6 million and $2.1 million, respectively, including amortization of certain customer-based intangible assets associated with the acquisition from Cordillera in November 2011, which is included as a reduction in revenue for financial reporting purposes.

Depreciation and Amortization

The provision for depreciation, which was 2.8 percent and 3.0 percent, respectively, of the average depreciable utility plant for 2013 and 2012, is provided on a straight-line method over the estimated service life of the utility assets. Depreciation is provided at the unit level for production plant and at the account or sub-account level for all other plant, and is based on the average life group method. In 2014, the provision for depreciation is projected to be 2.8 percent of the average depreciable utility plant. Amortization of intangible assets is computed using the straight-line method. Of the remaining amortizable intangible plant balance at December 31, 2013, 93.5 percent will be amortized over 9 years with 6.5 percent of the remaining amortizable intangible plant balance at December 31, 2013 being amortized over 26 years.. Amortization of plant acquisition adjustments is provided on a straight-line basis over the estimated remaining service life of the acquired asset. Plant acquisition adjustments include $148.3 million for the Redbud Plant, which are being amortized over a 27-year life and $3.3 million for certain substation facilities in OG&E's service territory, which are being amortized over a 26 to 59-year period.

Investment in Unconsolidated Affiliate

OGE Energy's investment in Enable is considered to be a variable interest entity because the owners of the equity at risk in this entity have disproportionate voting rights in relation to their obligations to absorb the entity's expected losses or to receive its expected residual returns. However, OGE Energy is not considered the primary beneficiary of Enable since it does not have the power to direct the activities of Enable that are considered most significant to the economic performance of Enable. As discussed above, OGE Energy accounts for the investment in Enable using the equity method of accounting. Under the equity method, the investment will be adjusted each period for contributions made, distributions received and the Company's share of the investee's comprehensive income. OGE Energy's maximum exposure to loss related to Enable is limited to OGE Energy's equity investment in Enable as presented on the Company's Consolidated Balance Sheet at December 31, 2013. The Company evaluates its equity method investments for impairment when events or changes in circumstances indicate there is a loss in value of the investment that is other than a temporary decline.

The Company considers distributions received from its unconsolidated affiliates which do not exceed cumulative equity in earnings subsequent to the date of investment to be a return on investment which are classified as operating activities in the Consolidated Statements of Cash Flows. The Company considers distributions received from its unconsolidated affiliates in excess of cumulative equity in earnings subsequent to the date of investment to be a return of investment which are classified as investing activities in the Consolidated Statements of Cash Flows.

Asset Retirement Obligations

The Company has previously recorded asset retirement obligations that are being amortized over their respective lives ranging from 20 to 74 years.

The following table summarizes changes to the Company's asset retirement obligations during the years ended December 31, 2013 and 2012.

(In millions)	**2013**	2012
Balance at January 1	**$ 54.0**	$ 24.8
Liabilities settled (A)	**(0.4)**	0.4
Accretion expense	**2.3**	1.9
Revisions in estimated cash flows (B)	**(0.7)**	26.9
Balance at December 31	**$ 55.2**	$ 54.0

(A) As a result of the formation of Enable on May 1, 2013, the Company has no obligations at December 31, 2013 under OGE Holdings' asset retirement obligations previously disclosed in the Company's 2012 10-K.
(B) Due to changes to OG&E's asset retirement obligations related to its wind farms as a result of changes in the assumption related to the timing of removal used in the valuation of the asset retirement obligations.

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

As a result of the formation of Enable Midstream Partners on May 1, 2013 and the Company's deconsolidation of Enogex Holdings, the Company no longer has intangible assets or goodwill.

The Company assesses its long-lived assets (inclusive of definite-lived intangible assets prior to the deconsolidation of Enogex Holdings) for impairment when there is evidence that events or changes in circumstances require an analysis of the recoverability of an asset's carrying amount. Estimates of future cash flows used to test the recoverability of long-lived assets and intangible assets shall include only the future cash flows (cash inflows less associated cash outflows) that are directly associated with and that are expected to arise as a direct result of the use and eventual disposition of the asset. The fair value of these assets is based on third-party evaluations, prices for similar assets, historical data and projected cash flows. An impairment loss is recognized when the sum of the expected future net cash flows is less than the carrying amount of the asset. The amount of any recognized impairment is based on the estimated fair value of the asset subject to impairment compared to the carrying amount of such asset. In 2011, the Company recorded a pre-tax impairment loss of $5.0 million, of which $2.5 million was the noncontrolling interest portion (see Note 4), related to the Atoka processing plant. The Company recorded no other material impairments in 2013, 2012 or 2011.

Allowance for Funds Used During Construction

For OG&E, allowance for funds used during construction is calculated according to the FERC pronouncements for the imputed cost of equity and borrowed funds. Allowance for funds used during construction, a non-cash item, is reflected as an increase to net other income and a reduction to interest expense in the Consolidated Statements of Income and as an increase to Construction Work in Progress in the Consolidated Balance Sheets. Allowance for funds used during construction rates, compounded semi-annually, were 8.33 percent, 8.93 percent and 8.71 percent for the years ended December 31, 2013, 2012 and 2011, respectively. The decrease in the allowance for funds used during construction rates in 2013 was primarily due to two factors. First, a decrease in the common equity cost rate caused the equity portion of allowance for equity funds used during construction to decrease. Second, an increase in the average daily balance of short term debt allowed the fixed commercial paper fees to be lower per dollar of short term debt, resulting in a lower short term debt rate, which caused the debt portion of allowance for funds used during construction to decrease.

Collection of Sales Tax

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

Revenue Recognition

General

OG&E reads its customers' meters and sends bills to its customers throughout each month. As a result, there is a significant amount of customers' electricity consumption that has not been billed at the end of each month. Unbilled revenue is presented in Accrued Unbilled Revenues on the Consolidated Balance Sheets and in Operating Revenues on the Consolidated Statements of Income based on estimates of usage and prices during the period. The estimates that management uses in this calculation could vary from the actual amounts to be paid by customers.

SPP Purchases and Sales

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

Fuel Adjustment Clauses

Variances in the actual cost of fuel used in electric generation and certain purchased power costs, as compared to the fuel component 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 its affiliate, Enable.

Income Taxes

The Company files consolidated income tax returns in the U.S. Federal jurisdiction and various state jurisdictions. Income taxes are generally allocated to each company in the affiliated group based on its stand-alone taxable income or loss. Federal investment tax credits previously claimed on electric utility property have been deferred and are being amortized to income over the life of the related property. The Company uses the asset and liability method of accounting for income taxes. Under this method, a deferred tax asset or liability is recognized for the estimated future tax effects attributable to temporary differences between the financial statement basis and the tax basis of assets and liabilities as well as tax credit carry forwards and net operating loss carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in the period of the change. The Company recognizes interest related to unrecognized tax benefits in interest expense and recognizes penalties in other expense.

Accrued Vacation

The Company accrues vacation pay monthly by establishing a liability for vacation earned. Vacation may be taken as earned and is charged against the liability. At the end of each year, the liability represents the amount of vacation earned, but not taken. OGE employees can carryover no more than 80 hours to be used in future years.

Accumulated Other Comprehensive Income (Loss)

The following table summarizes changes in the components of accumulated other comprehensive loss attributable to OGE Energy during 2013. All amounts below are presented net of tax and noncontrolling interest.

	Pension Plan and Restoration of Retirement Income Plan		Postretirement Benefit Plans					
(In millions)	Net loss	Prior service cost	Net loss	Prior service cost	Deferred commodity contracts hedging gains	Deferred interest rate swap hedging losses	Less: Noncontrolling interest	Total
Balance at December 31, 2012	$ (49.3)	$ 0.1	$ (15.7)	$ 7.2	$ 0.1	$ (0.5)	$ (9.0)	$ (49.1)
Other comprehensive income before reclassifications	12.4	—	6.9	—	—	—	—	19.3
Amounts reclassified from accumulated other comprehensive income (loss) (A)	6.7	—	2.0	(1.8)	0.6	0.3	0.1	7.7
Deconsolidation of Enogex Holdings	2.8	—	1.0	(0.3)	(0.7)	—	8.9	(6.1)
Net current period other comprehensive income (loss)	21.9	—	9.9	(2.1)	(0.1)	0.3	9.0	20.9
Balance at December 31, 2013	$ (27.4)	$ 0.1	$ (5.8)	$ 5.1	$ —	$ (0.2)	$ —	$ (28.2)

(A) Includes $3.0 million of pension settlement charges.

The following table summarizes significant amounts reclassified out of accumulated other comprehensive loss by the respective line items in net income during the year ended December 31, 2013.

Details about Accumulated Other Comprehensive Loss Components	Amount Reclassified from Accumulated Other Comprehensive Loss	Affected Line Item in the Statement Where Net Income is Presented
(In millions)	**Year Ended December 31, 2013**	
Gains (losses) on cash flow hedges		
Commodity contracts	$ (1.0)	Cost of sales
Interest rate swap	(0.4)	Interest expense
	(1.4)	Total before tax
	(0.5)	Tax benefit
	$ (0.9)	Net of tax
Amortization of defined benefit pension items		
Actuarial gains (losses)	$ (6.1)	(A)
Settlement cost	(4.9)	(A)
	(11.0)	Total before tax
	(4.3)	Tax benefit
	(6.7)	Net of tax
	(0.1)	Noncontrolling interest
	$ (6.6)	Net of tax and noncontrolling interest
Amortization of postretirement benefit plan items		
Actuarial gains (losses)	$ (3.3)	(A)
Prior service cost	2.9	(A)
	(0.4)	Total before tax
	(0.2)	Tax benefit
	$ (0.2)	Net of tax
Total reclassifications for the period	$ (7.7)	Net of tax and noncontrolling interest

(A) These accumulated other comprehensive income (loss) components are included in the computation of net periodic benefit cost (see Note 13 for additional information).

The amounts in accumulated other comprehensive loss at December 31, 2013 that are expected to be recognized into earnings in 2014 are as follows:

(In millions)	
Pension Plan and Restoration of Retirement Income Plan	
Net loss	$ (1.7)
Prior service cost	(0.1)
Postretirement Benefit Plans	
Net loss	(0.8)
Prior service cost	1.8
Deferred commodity contracts hedging gains	—
Deferred interest rate swap hedging losses	(0.2)
Total, net of tax	$ (1.0)

Environmental Costs

Accruals for environmental costs are recognized when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. Costs are charged to expense or deferred as a regulatory asset based on expected recovery from customers in future rates, if they relate to the remediation of conditions caused by past operations or if they are not expected to mitigate or prevent contamination from future operations. Where environmental expenditures relate to facilities currently in use, such as pollution control equipment, the costs may be capitalized and depreciated over the future service periods. Estimated remediation costs are recorded at undiscounted amounts, independent of any insurance or rate recovery, based on prior experience, assessments and current technology. Accrued obligations are regularly adjusted as environmental assessments and estimates are revised, and remediation efforts proceed. For sites where OG&E has been designated as one of several potentially responsible parties, the amount accrued represents OG&E's estimated share of the cost. The Company had $6.2 million and $5.8 million in accrued environmental liabilities at December 31, 2013 and 2012, respectively, which are included in the summary of asset retirement obligations above.

Forward Stock Split

On May 16, 2013, the Company's Board of Directors approved a 2-for-1 forward stock split of the Company's common stock, effective July 1, 2013, which entitled each shareholder of record to receive two shares for every one share of Company stock owned by the shareholder. In connection with the stock split, an amendment to the Company's Articles of Incorporation was approved on May 16, 2013 which increased the number of authorized shares of common stock from 225 million to 450 million. All share and per share amounts presented within this Form 10-K reflect the effects of the stock split.

Reclassifications

As discussed in Note 14, the former natural gas transportation and storage segment and natural gas gathering and processing segment have been combined into the natural gas midstream operations segment and have been restated for all prior periods presented. Effective May 1, 2013, the Company deconsolidated its previously held investment in Enogex Holdings and acquired an equity interest in Enable.

2. Accounting Pronouncements

In July 2013, the Emerging Issues Task Force issued "Presentation of an Unrecognized Tax Benefit When a Net Operating Loss Carryforward or Tax Credit Carryforward Exists." The new standard requires entities to present an unrecognized tax benefit, or a portion of an unrecognized tax benefit, in the statement of financial position as a reduction to a deferred tax asset for a net operating loss carryforward or a tax credit carryforward, except as follows: to the extent that a net operating loss carryforward or tax credit carryforward at the reporting date is not available under the tax law of the applicable jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position, the unrecognized tax benefit would be presented in the statement of financial position as a liability. The new standard is applicable for all entities that have unrecognized tax benefits when a net operating loss carryforward or a tax credit carryforward exists. The new standard is effective for interim and annual reporting periods beginning after December 15, 2013 and does not require any new financial statement disclosures. This new standard may be applied retrospectively or prospectively with early adoption permitted. The Company retrospectively adopted this new standard effective January 1, 2013.

In December 2011, the Financial Accounting Standards Board issued "Balance Sheet: Disclosures about Offsetting Assets and Liabilities." The new standard requires entities to disclose information about financial instruments and derivative instruments that are either offset on the balance sheet or are subject to a master netting arrangement, including providing both gross information and net information for recognized assets and liabilities, the net amounts presented on an entity's balance sheet and a description of the rights of setoff associated with these assets and liabilities. The new standard is applicable for all entities that have financial instruments and derivative instruments shown using a net presentation on an entity's balance sheet or are subject to a master netting arrangement. On January 31, 2013, the Financial Accounting Standards Board issued an update to this standard clarifying that the scope includes derivatives, including bifurcated embedded derivatives, repurchase agreements and reverse repurchase agreements, and securities borrowing and securities lending transactions that are either offset or are subject to a master netting arrangement or similar agreement. The new standard is effective for interim and annual reporting periods for fiscal years beginning on or after January 1, 2013 and is required to be applied retrospectively for all periods presented. The Company adopted this new standard effective January 1, 2013.

In February 2013, the Financial Accounting Standards Board issued "Comprehensive Income: Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income." The new standard requires an entity to provide information about the amounts reclassified out of accumulated other comprehensive income by component. In addition, the new standard requires an entity to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items in net income but only if the amount reclassified is required under U.S. GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under U.S. GAAP to be reclassified in their entirety to net income, an entity is required to cross-reference to other disclosures required under U.S. GAAP that provide additional detail about those amounts. The new standard is applicable for all entities that issue financial statements that are presented in conformity with U.S. GAAP and that report items of other comprehensive income. The new standard is effective for interim and annual reporting periods for fiscal years beginning after December 15, 2012 and is required to be applied prospectively. The Company adopted this new standard effective January 1, 2013.

3. Investment in Unconsolidated Affiliates and Related Party Transactions

On March 14, 2013, OGE Energy entered into a Master Formation Agreement with the ArcLight group and CenterPoint Energy, Inc., pursuant to which OGE Energy, the ArcLight Group and CenterPoint Energy, Inc., agreed to form Enable Midstream Partners to own and operate the midstream businesses of OGE Energy and CenterPoint that will initially be structured as a private limited partnership. This transaction closed on May 1, 2013.

Pursuant to the Master Formation Agreement, OGE Energy and the ArcLight group indirectly contributed 100 percent of the equity interests in Enogex LLC to Enable. The Company determined that its contribution of Enogex LLC to Enable met the requirements of being in substance real estate and was recorded at historical cost. Enogex LLC is a provider of integrated natural gas midstream services. Enogex LLC is engaged in the business of gathering, processing, transporting and storing natural gas. Most of Enogex LLC's natural gas gathering, processing, transportation and storage assets are strategically located in the Arkoma and Anadarko basins of Oklahoma and the Texas Panhandle. CenterPoint Energy Field Services, LLC, a Delaware limited liability company and, prior to the closing of the transaction on May 1, 2013, a wholly owned subsidiary of CenterPoint, that provides natural gas gathering and processing services for certain natural gas fields in the Mid-continent region of the United States, was converted into a Delaware limited partnership that became Enable Midstream Partners, LP. CenterPoint contributed to Enable its equity interests in each of (i) CenterPoint Energy Gas Transmission Company, LLC, a Delaware limited liability company that is an interstate pipeline that provides natural gas transportation, storage and pipeline services to customers principally in Arkansas, Louisiana, Oklahoma and Texas, (ii) MRT, a Delaware limited liability company that is an interstate pipeline that provides natural gas transportation, storage and pipeline services to customers principally in Arkansas, Illinois and Missouri and (iii) certain of its other midstream subsidiaries and caused its subsidiary CenterPoint Energy Southeastern Pipelines Holding, LLC to contribute a 24.95 percent interest in Southeast Supply Header, LLC, a Delaware limited liability company. CenterPoint indirectly owned a 50 percent interest in Southeast Supply Header, LLC, which owns a 1.0 billion cubic feet per day, 274-mile interstate pipeline that runs from the Perryville Hub in Louisiana to Coden, Alabama.

Immediately prior to closing, on May 1, 2013, the ArcLight group contributed $107.0 million and OGE Energy contributed $9.1 million to Enogex LLC in order to pay down short-term debt. At December 31, 2013, OGE Energy, through its wholly owned subsidiary OGE Holdings, holds 28.5 percent of the limited partner interests in Enable.

CenterPoint has certain put rights, and Enable has certain call rights, exercisable with respect to any interest in Southeast Supply Header, LLC retained by CenterPoint following the formation of Enable Midstream Partners, under which CenterPoint would contribute to Enable Midstream Partners CenterPoint's retained interest in Southeast Supply Header, LLC at a price equal to the fair market value of such interest at the time the put right or call right is exercised. If CenterPoint were to exercise such put right or Enable were to exercise such call right, CenterPoint's retained interest in Southeast Supply Header, LLC would be contributed to Enable in exchange for consideration consisting of a specified number of limited partnership units and, subject to certain restrictions, a cash payment, payable either from CenterPoint to Enable or from Enable to CenterPoint, in an amount such that the total consideration exchanged is equal in value to the fair market value of the contributed interest in Southeast Supply Header, LLC.

The general partner of Enable is equally controlled by CenterPoint and OGE Energy, who each have 50 percent of the management rights. CenterPoint and OGE Energy also own a 40 percent and 60 percent interest, respectively, in any incentive distribution rights to be held by the general partner of Enable following an initial public offering of Enable. In addition, for a period of time, the ArcLight group will have certain protective rights and approval rights over certain material activities of Enable, including material increases in capital expenditures and certain equity issuances, entering into transactions with related parties and acquiring, pledging or disposing of certain material assets. The general partner of Enable will initially be governed by a board made up of an equal number of representatives designated by each of CenterPoint Energy, Inc. and OGE Energy. Based on the

50/50 management ownership, with neither company having control, effective May 1, 2013, OGE Energy deconsolidated its interest in Enogex Holdings LLC and began accounting for its interest in Enable using the equity method of accounting.

Pursuant to a Registration Rights Agreement dated as of May 1, 2013, OGE Energy and CenterPoint Energy, Inc. agreed to initiate the process for the sale of an equity interest in Enable in an initial public offering. Enable filed a registration statement for the initial public offering on November 26, 2013 and, subject to limited exceptions, plans to consummate the initial public offering during the first quarter of 2014. The initial public offering is subject to market conditions and OGE Energy can give no assurances that the initial public offering will be consummated.

Effective May 1, 2013, Enable entered into a $1.4 billion, five-year senior unsecured revolving credit facility in accordance with the terms of the Master Formation Agreement and Enogex LLC's $400.0 million revolving credit facility was terminated.

Subject to the exceptions provided below, pursuant to the terms of an Omnibus Agreement dated as of May 1, 2013 among OGE Energy, the ArcLight group and CenterPoint Energy, Inc., each of OGE Energy and CenterPoint Energy, Inc. will be required to hold or otherwise conduct all of its respective Midstream Operations (as defined below) located within the United States in Enable. This restriction will cease to apply to both OGE Energy and CenterPoint Energy, Inc. as soon as either OGE Energy or CenterPoint Energy, Inc. ceases to hold (i) any interest in the general partner of Enable or (ii) at least 20 percent of the limited partner interests of Enable. "Midstream Operations" generally means, subject to certain exceptions, the gathering, compression, treatment, processing, blending, transportation, storage, isomerization and fractionation of crude oil and natural gas, its associated production water and enhanced recovery materials such as carbon dioxide, and its respective constituents and the following products: methane, NGLs (Y-grade, ethane, propane, normal butane, isobutane and natural gasoline), condensate, and refined products and distillates (gasoline, refined product blendstocks, olefins, naphtha, aviation fuels, diesel, heating oil, kerosene, jet fuels, fuel oil, residual fuel oil, heavy oil, bunker fuel, cokes, and asphalts), to the extent such activities are located within the United States.

In addition, if OGE Energy or CenterPoint Energy, Inc. acquires any assets or equity of any person engaged in Midstream Operations with a value in excess of $50 million (or $100 million in the aggregate with such party's other acquired Midstream Operations that have not been offered to Enable), the acquiring party will be required to offer Enable the opportunity to acquire such assets or equity for such value; provided, that the acquiring party will not be obligated to offer any such assets or equity to Enable if the acquiring party intends to cease using them in Midstream Operations within 12 months. If Enable does not exercise its option, then the acquiring party will be free to retain and operate such Midstream Operations; provided, however, that if the fair market value of such Midstream Operations is greater than 66 2/3 percent of the fair market value of all of the assets being acquired in such transaction, then the acquiring party will be required to dispose of such Midstream Operations within 24 months.

As long as the ArcLight group has certain protective rights, the ArcLight group will be prohibited from pursuing any transaction independently from Enable (i) if the ArcLight group's consent is required for Enable to pursue such transaction and (ii) the ArcLight group affirmatively votes not to consent to such transaction.

On May 1, 2013, OGE Energy, OGE Holdings and Enable entered into a Seconding Agreement. During the term of the Seconding Agreement, OGE Holdings' employees will continue to perform services for Enable and its subsidiaries.

Distributions received from Enable were $51.7 million during the year ended December 31, 2013.

Related Party Transactions

As OGE Energy's interest in Enogex Holdings was deconsolidated on May 1, 2013, operating costs charged and related party transactions between the Company and its affiliate, Enable, after May 1, 2013, which were previously eliminated in consolidation, are discussed below.

OGE Energy charged operating costs to Enogex Holdings/Enable of $17.8 million during 2013. OGE Energy charges operating costs to its subsidiaries and unconsolidated affiliate based on several factors. Operating costs directly related to specific subsidiaries or unconsolidated affiliate are assigned to those subsidiaries or unconsolidated affiliate. Where more than one subsidiary or unconsolidated affiliate benefits from certain expenditures, the costs are shared between those subsidiaries and unconsolidated affiliate receiving the benefits. Operating costs incurred for the benefit of all subsidiaries and unconsolidated affiliate are allocated among the subsidiaries and unconsolidated affiliate, either as overhead based primarily on labor costs or using the "Distrigas" method. The Distrigas method is a three-factor formula that uses an equal weighting of payroll, net operating revenues and gross property, plant and equipment. OGE Energy adopted the Distrigas method in January 1996 as a result of a recommendation by the OCC Staff. OGE Energy believes this method provides a reasonable basis for allocating common expenses.

Related Party Transactions with Enable

(In millions)		Eight Months Ended December 31, 2013
Operating Revenues:		
Electricity to power electric compression assets	$	7.7
Cost of Sales:		
Natural gas transportation services	$	23.2
Natural gas storage services		8.6
Natural gas purchases		14.8

Summarized Financial Information of Enable

As Enable began operations on May 1, 2013, summarized unaudited financial information for 100 percent of Enable is presented below at December 31, 2013 and for the eight months ended December 31, 2013.

Balance Sheet		December 31, 2013
		(In millions)
Current assets	$	549
Non-current assets		10,683
Current liabilities		720
Non-current liabilities		2,331

Income Statement		Eight Months Ended December 31, 2013
		(In millions)
Operating revenues	$	2,122.6
Cost of sales		1,240.5
Operating income		321.9
Net income		288.6

Enable concluded that the formation of Enable was considered a business combination, and CenterPoint Midstream was the acquirer of Enogex Holdings for accounting purposes. Under this method, the fair value of the consideration paid by CenterPoint Midstream for Enogex Holdings is allocated to the assets acquired and liabilities assumed on May 1, 2013 based on their fair value. Enogex Holdings' assets, liabilities and equity have accordingly been adjusted to estimated fair value as of May 1, 2013, resulting in an increase to equity of $2.2 billion. Determining the fair value of certain assets and liabilities assumed is judgmental in nature and often involves the use of significant estimates and assumptions. Enable utilized appraisers to assist in the determination of fair value of certain assets.

OGE Energy recorded equity in earnings of unconsolidated affiliates of $101.9 million for the eight months ended December 31, 2013. Equity in earnings of unconsolidated affiliates includes OGE Energy's 28.5 percent share of Enable earnings adjusted for the amortization of the basis difference of OGE Energy's original investment in Enogex and its underlying equity in net assets of Enable, based on historical cost as of May 1, 2013. The basis difference is being amortized over approximately 30 years, the average life of the assets to which the basis difference is attributed. Equity in earnings of unconsolidated affiliates is also adjusted for the elimination of the Enogex Holdings fair value adjustments described above.

Reconciliation of Equity in Earnings of Unconsolidated Affiliates		Eight Months Ended December 31, 2013
		(In millions)
OGE's 28.5% share of Enable Net Income	$	82.1
Amortization of basis difference		9.4
Elimination of Enogex Holdings fair value and other adjustments		10.4
OGE's Equity in earnings of unconsolidated affiliates	$	101.9

4. Impairment of Assets

In August 2011, Enogex recorded a pre-tax impairment loss related to its Atoka joint venture which operated a 20 MMcf/d refrigeration processing plant which processed gas gathered in the Atoka, OK area. The processing plant was leased on a month-to-month basis. In August 2011, management made a decision to use third-party processing exclusively for gathered volumes dedicated to Atoka and, therefore, to take the processing plant out of service and return it to the lessor in accordance with the rental agreement. As a result Enogex recorded a pre-tax impairment loss of $5.0 million associated with the cost it had capitalized in connection with the installation of the leased plant as those costs were determined to be not recoverable through future cash flows. The noncontrolling interest portion of the pre-tax impairment loss was $2.5 million which was included in Net Income Attributable to Noncontrolling Interests in the Company's Consolidated Statement of Income.

5. Fair Value Measurements

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

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

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

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

The Company utilizes the market approach in determining the fair value of its derivative positions by using either NYMEX published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX published market prices may be considered Level 1 if they are settled through a NYMEX clearing broker account with daily margining. Over-the-counter derivatives with NYMEX based prices are considered Level 2 due to the impact of counterparty credit risk. Valuations based on independent broker pricing or broker/dealer valuations may be classified as Level 2 only to the extent they may be validated by an additional source of independent market data for an identical or closely related active market. In certain less liquid markets or for longer-term contracts, forward prices are not as readily available. In these circumstances, contracts are valued using internally developed methodologies that consider historical relationships among various quoted prices in active markets that result in management's best estimate of fair value. These contracts are classified as Level 3.

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

Contracts with Master Netting Arrangements

Fair value amounts recognized for forward, interest rate swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Consolidated Balance Sheets. The Company has presented the fair values of its derivative contracts under master netting agreements using a net fair value presentation.

The Company had no financial instruments measured at fair value on a recurring basis at December 31, 2013. The following table summarizes the Company's assets and liabilities that are measured at fair value on a recurring basis at December 31, 2012 as well as presents the Company's commodity contracts fair value to PRM Assets and Liabilities on the Company's Consolidated Balance Sheet at December 31, 2012. There were no Level 3 investments held at December 31, 2012.

December 31, 2012				
(In millions)	Commodity Contracts		Gas Imbalances (A)	
	Assets	Liabilities	Assets (B)	Liabilities (C)
Quoted market prices in active market for identical assets (Level 1)	$ 5.0	$ 5.0	$ —	$ —
Significant other observable inputs (Level 2)	0.5	0.5	3.1	3.8
Total fair value	5.5	5.5	3.1	3.8
Netting adjustments	(5.0)	(5.2)	—	—
Total	$ 0.5	$ 0.3	$ 3.1	$ 3.8

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

(B) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of $5.9 million at December 31, 2012, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

(C) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of $1.2 million at December 31, 2012, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

The following table summarizes the fair value and carrying amount of the Company's financial instruments at December 31, 2013 and December 31, 2012.

	2013		2012	
December 31 *(In millions)*	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Long-Term Debt				
OG&E Senior Notes	**$ 2,154.5**	**$ 2,405.0**	$ 1,904.2	$ 2,401.6
OG&E Industrial Authority Bonds	**135.4**	**135.4**	135.4	135.4
OG&E Tinker Debt	**10.3**	**9.1**	10.7	10.0
OGE Energy Senior Notes	**99.9**	**103.1**	99.9	106.3
Enogex LLC Senior Notes	**(A)**	**(A)**	448.4	493.4
Enogex LLC Term Loan	**(A)**	**(A)**	250.0	250.0

(A) As a result of the formation of Enable on May 1, 2013 and the Company's deconsolidation of Enogex Holdings, the Company's consolidated financial statements do not include any obligations for the Enogex LLC Senior Notes and Enogex LLC Term Loan as of May 1, 2013.

The carrying value of the financial instruments included in the Consolidated Balance Sheets approximates fair value except for long-term debt which is valued at the carrying amount. The fair value of the Company's long-term debt is based on quoted market prices and estimates of current rates available for similar issues with similar maturities and is classified as Level 2 in the fair value hierarchy.

6. Derivative Instruments and Hedging Activities

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

Interest Rate Risk

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

Credit Risk

The Company is exposed to certain credit risks relating to its ongoing business operations. Credit risk includes the risk that counterparties that owe the Company money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, the Company may be forced to enter into alternative arrangements. In that event, the Company's financial results could be adversely affected and the Company could incur losses.

Cash Flow Hedges

For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of Accumulated Other Comprehensive Income (Loss) and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portion of a derivative's change in fair value or hedge components excluded from the assessment of effectiveness is recognized currently in earnings. The Company measures the ineffectiveness of commodity cash flow hedges using the change in fair value method whereby the change in the expected future cash flows designated as the hedge transaction are compared to the change in fair value of the hedging instrument. Forecasted transactions, which are designated as the hedged transaction in a cash flow hedge, are regularly evaluated to assess whether they continue to be probable of occurring. If the forecasted transactions are no longer probable of occurring, hedge accounting will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings.

The Company previously designated as cash flow hedges derivatives used to manage commodity price risk exposure for OGE Holdings'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). The Company also previously designated as cash flow hedges certain derivatives used to manage natural gas commodity exposure for certain natural gas storage inventory positions. Due to the deconsolidation effective May 1, 2013, the Company had no instruments designated as cash flow hedges at December 31, 2013.

Fair Value Hedges

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

At December 31, 2013 and 2012, the Company had no derivative instruments that were designated as fair value hedges.

Derivatives Not Designated As Hedging Instruments

Derivative instruments not designated as hedging instruments were utilized in OGE Holdings' asset management activities and were reflected in consolidated results prior to the deconsolidation of Enogex on May 1, 2013. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized in the period in which it occurred.

Quantitative Disclosures Related to Derivative Instruments

At December 31, 2013, the Company has no derivative instruments that were designated as cash flow hedges.

At December 31, 2012, the Company had the following derivative instruments that were designated as cash flow hedges.

(In millions)	2012 Gross Notional Volume (A)
Enogex hedges	
Natural gas sales	3.7

(A) Natural gas in MMBtu's.

At December 31, 2012, the Company had the following derivative instruments that were not designated as hedging instruments.

(In millions)	Gross Notional Volume (A)	
	Purchases	Sales
Natural gas (B)		
Physical (C)(D)	7.0	30.1
Fixed Swaps/Futures	16.2	17.9
Basis Swaps	7.3	6.7

(A) Natural gas in MMBtu's.
(B) 95.1 percent of the natural gas contracts have durations of one year or less, 2.9 percent have durations of more than one year and less than two years and 2.0 percent have durations of more than two years.
(C) Of the natural gas physical purchases and sales volumes not designated as hedges, the majority are priced based on a monthly or daily index and the fair value is subject to little or no market price risk.
(D) Natural gas physical sales volumes exceed natural gas physical purchase volumes due to the marketing of natural gas volumes purchased via Enogex's processing contracts, which are not derivative instruments and are excluded from the table above.

Balance Sheet Presentation Related to Derivative Instruments

The Company had no derivative instruments included in its Consolidated Balance Sheet at December 31, 2013. The fair value of the derivative instruments that are presented in the Company's Consolidated Balance Sheet at December 31, 2012 are as follows:

		Fair Value	
Instrument	Balance Sheet Location	Assets	Liabilities
		(In millions)	
Derivatives Designated as Hedging Instruments			
Natural Gas			
Financial Futures/Swaps	Other Current Assets	$ —	$ 0.5
Total		$ —	$ 0.5
Derivatives Not Designated as Hedging Instruments			
Natural Gas			
Financial Futures/Swaps	Current PRM	$ 0.1	$ —
	Other Current Assets	5.0	4.7
Physical Purchases/Sales	Current PRM	0.4	0.3
Total		$ 5.5	$ 5.0
Total Gross Derivatives (A)		$ 5.5	$ 5.5

(A) See Note 5 for a reconciliation of the Company's total derivatives fair value to the Company's Consolidated Balance Sheet at December 31, 2012.

Income Statement Presentation Related to Derivative Instruments

The following tables present the effect of derivative instruments on the Company's Consolidated Statement of Income in 2013.

Derivatives in Cash Flow Hedging Relationships

(In millions)	Amount Recognized in Other Comprehensive Income	Amount Reclassified from Accumulated Other Comprehensive Income (Loss) into Income	Amount Recognized in Income
Natural Gas Financial Futures/Swaps	$ (0.2)	$ 5.2	$ —
Interest Rate Swap	—	(0.2)	—
Total	$ (0.2)	$ 5.0	$ —

Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income
Natural Gas Physical Purchases/Sales	$ (6.1)
Natural Gas Financial Futures/Swaps	1.0
Total	$ (5.1)

The following tables present the effect of derivative instruments on the Company's Consolidated Statement of Income in 2012.

Derivatives in Cash Flow Hedging Relationships

(In millions)	Amount Recognized in Other Comprehensive Income	Amount Reclassified from Accumulated Other Comprehensive Income (Loss) into Income	Amount Recognized in Income
Natural Gas Financial Futures/Swaps	0.5	5.2	—
Interest Rate Swap	—	(0.4)	—
Total	$ 0.5	$ 4.8	$ —

Derivatives Not Designated as Hedging Instruments

(In millions)	Amount Recognized in Income
Natural Gas Physical Purchases/Sales	$ (11.7)
Natural Gas Financial Futures/Swaps	1.1
Total	$ (10.6)

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

Derivatives in Cash Flow Hedging Relationships

(In millions)	Amount Recognized in Other Comprehensive Income	Amount Reclassified from Accumulated Other Comprehensive Income (Loss) into Income	Amount Recognized in Income
NGLs Financial Options	$ (8.4)	$ (9.8)	$ —
Natural Gas Financial Futures/Swaps	2.9	(30.4)	—
Interest Rate Swap	—	(0.4)	—
Total	$ (5.5)	$ (40.6)	$ —

Derivatives Not Designated as Hedging Instruments

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

For derivatives designated as cash flow hedges in the tables above, amounts reclassified from Accumulated Other Comprehensive Income (Loss) into income (effective portion) and amounts recognized in income (ineffective portion) for the years ended December 31, 2012 and 2011, if any, are reported in Operating Revenues. For derivatives not designated as hedges in the tables above, amounts recognized in income for the years ended December 31, 2012 and 2011, if any, are reported in Operating Revenues.

Credit-Risk Related Contingent Features in Derivative Instruments

At December 31, 2013, the Company had no derivative instruments that contain credit-risk related contingent features. In the event Moody's Investors Services or Standard & Poor's Ratings Services were to lower the Company's senior unsecured debt rating to a below investment grade rating, at December 31, 2012, the Company would have been required to post $0.2 million of cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that were in a net liability position at December 31, 2012.

7. Stock-Based Compensation

In 2013, the Company adopted, and its shareowners approved, the 2013 Stock Incentive Plan. The 2013 Plan replaced the 2008 Plan and no further awards will be granted under the 2008 Plan. Under the 2013 Stock Incentive Plan, restricted stock, restricted stock units, stock options, stock appreciation rights and performance units may be granted to officers, directors and other key employees of the Company and its subsidiaries. The Company has authorized the issuance of up to 7,400,000 shares under the 2013 Stock Incentive Plan.

The following table summarizes the Company's pre-tax compensation expense and related income tax benefit for the years ended December 31, 2013, 2012 and 2011 related to the Company's performance units and restricted stock.

Year ended December 31 *(In millions)*		**2013**		2012		2011
Performance units						
Total shareholder return	**$**	**8.4**	$	8.0	$	8.2
Earnings per share		**2.3**		4.2		5.5
Total performance units		**10.7**		12.2		13.7
Restricted stock		**0.4**		0.6		1.0
Total compensation expense		**11.1**		12.8		14.7
Less: Amount paid by unconsolidated affiliates		**3.1**		—		—
Net compensation expense	**$**	**8.0**	$	12.8	$	14.7
Income tax benefit	**$**	**3.1**	$	4.9	$	5.7

The Company has issued new shares to satisfy stock option exercises, restricted stock grants and payouts of earned performance units. In 2013, 2012 and 2011, there were 548,344 shares, 849,110 shares and 623,246 shares, respectively, of new common stock issued pursuant to the Company's stock incentive plans related to exercised stock options, restricted stock grants (net of forfeitures) and payouts of earned performance units. In 2013, there were 11,318 shares of restricted stock returned to the Company to satisfy tax liabilities.

Performance Units

Under the 2008 Stock Incentive Plan, the Company has issued performance units which represent the value of one share of the Company's common stock. The performance units provide for accelerated vesting if there is a change in control (as defined in the 2008 Stock Incentive Plan). Each performance unit is subject to forfeiture if the recipient terminates employment with the

Company or a subsidiary prior to the end of the three-year award cycle for any reason other than death, disability or retirement. In the event of death, disability or retirement, a participant will receive a prorated payment based on such participant's number of full months of service during the award cycle, further adjusted based on the achievement of the performance goals during the award cycle.

The performance units granted based on total shareholder return are contingently awarded and will be payable in shares of the Company's common stock subject to the condition that the number of performance units, if any, earned by the employees upon the expiration of a three-year award cycle (i.e., three-year cliff vesting period) is dependent on the Company's total shareholder return ranking relative to a peer group of companies. The performance units granted based on earnings per share are contingently awarded and will be payable in shares of the Company's common stock based on the Company's earnings per share growth over a three-year award cycle (i.e., three-year cliff vesting period) compared to a target set at the time of the grant by the Compensation Committee of the Company's Board of Directors. All of these performance units are classified as equity in the Consolidated Balance Sheet. If there is no or only a partial payout for the performance units at the end of the award cycle, the unearned performance units are cancelled. Payout requires approval of the Compensation Committee of the Company's Board of Directors. Payouts, if any, are all made in common stock and are considered made when the payout is approved by the Compensation Committee.

As a result of the formation of Enable on May 1, 2013, 2013 performance unit grants to OGE Holdings' employees that were previously based on earnings before interest, taxes, depreciation and amortization were converted to performance units based on total shareholder return or earnings per share. Total 2013 performance unit grants converted were 91,390, comprised of 45,596 total shareholder return performance units with a $25.89 grant date fair value and 45,794 earnings per share performance units with a $26.73 grant date fair value. As a result of a modification to the 2012 performance unit grants, 2012 performance unit grants to OGE Holdings' employees that were previously based on earnings before interest, taxes and depreciation and amortization were converted to performance units based on total shareholder return or earnings per share. Total 2012 performance unit grants converted were 82,930, comprised of 41,554 total shareholder return performance units with a $47.71 grant date fair value and 41,376 earnings per share performance units with a $34.94 grant date fair value. The amount of these performance units were adjusted for the effects of the stock split. The impact of the modification of the performance unit grants on stock-based compensation expense for 2013 was not material.

Performance Units – Total Shareholder Return

The fair value of the performance units based on total shareholder return was estimated on the grant date using a lattice-based valuation model that factors in information, including the expected dividend yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance units. Compensation expense for the performance units is a fixed amount determined at the grant date fair value and is recognized over the three-year award cycle regardless of whether performance units are awarded at the end of the award cycle. Dividends are not accrued or paid during the performance period and, therefore, are not included in the fair value calculation. Expected price volatility is based on the historical volatility of the Company's common stock for the past three years and was simulated using the Geometric Brownian Motion process. The risk-free interest rate for the performance unit grants is based on the three-year U.S. Treasury yield curve in effect at the time of the grant. The expected life of the units is based on the non-vested period since inception of the award cycle. There are no post-vesting restrictions related to the Company's performance units based on total shareholder return. The number of performance units granted based on total shareholder return and the assumptions used to calculate the grant date fair value of the performance units based on total shareholder return are shown in the following table.

	2013	2012	2011
Number of units granted	**316,162**	338,678	427,442
Fair value of units granted	**$ 25.89**	$ 25.91	$ 23.05
Expected dividend yield	**2.8%**	3.0%	3.2%
Expected price volatility	**20.0%**	22.0%	33.0%
Risk-free interest rate	**0.37%**	0.38%	1.40%
Expected life of units (in years)	**2.84**	2.87	2.87

Performance Units – Earnings Per Share

The fair value of the performance units based on earnings per share is based on grant date fair value which is equivalent to the price of one share of the Company's common stock on the date of grant. The fair value of performance units based on earnings per share varies as the number of performance units that will vest is based on the grant date fair value of the units and the probable outcome of the performance condition. The Company reassesses at each reporting date whether achievement of the performance condition is probable and accrues compensation expense if and when achievement of the performance condition is probable. As a result, the compensation expense recognized for these performance units can vary from period to period. There are no post-vesting restrictions related to the Company's performance units based on earnings per share. The number of performance units granted based on earnings per share and the grant date fair value are shown in the following table.

	2013	2012	2011
Number of units granted	**74,570**	81,594	142,476
Fair value of units granted	**$ 26.73**	$ 23.82	$ 20.81

Restricted Stock

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

The fair value of the restricted stock was based on the closing market price of the Company's common stock on the grant date. Compensation expense for the restricted stock is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over a three-year vesting period. Also, the Company treats its restricted stock as multiple separate awards by recording compensation expense separately for each tranche whereby a substantial portion of the expense is recognized in the earlier years in the requisite service period. Dividends are accrued and paid during the vesting period and, therefore, are included in the fair value calculation. The expected life of the restricted stock is based on the non-vested period since inception of the three-year award cycle. There are no post-vesting restrictions related to the Company's restricted stock. The number of shares of restricted stock granted and the grant date fair value are shown in the following table.

	2013	2012	2011
Shares of restricted stock granted	**5,940**	10,824	35,804
Fair value of restricted stock granted	**$ 29.71**	$ 26.72	$ 24.41

A summary of the activity for the Company's performance units and restricted stock at December 31, 2013 and changes in 2013 are shown in the following table.

	Performance Units					
	Total Shareholder Return		Earnings Per Share		Restricted Stock	
(dollars in millions)	Number of Units	Aggregate Intrinsic Value	Number of Units	Aggregate Intrinsic Value	Number of Shares	Aggregate Intrinsic Value
Units/Shares Outstanding at 12/31/12	1,069,128		327,838		49,106	
Granted	316,162 (A)		74,570 (A)		5,940	
Modification	87,150 (B)		87,170 (B)		N/A	
Converted	(377,266) (C)	$ 22.1	(125,760) (C)	$ 7.4	N/A	
Vested	N/A		N/A		(30,242)	$ 0.9
Forfeited	(33,114)		(9,792)		(1,176)	
Units/Shares Outstanding at 12/31/13	1,062,060	$ 50.9	354,026	$ 13.9	23,628	$ 0.8
Units/Shares Fully Vested at 12/31/13	355,078	$ 19.3	118,350	$ 8.0		

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

(B) These amounts represent the performance unit grants previously based on earnings before interest, taxes, depreciation and amortization that were converted to performance units based on total shareholder return or earnings per share as a result of the formation of Enable.

(C) These amounts represent performance units that vested at December 31, 2012 which were settled in February 2013.

A summary of the activity for the Company's non-vested performance units and restricted stock at December 31, 2013 and changes in 2013 are shown in the following table.

	Performance Units									
	Total Shareholder Return				Earnings Per Share				Restricted Stock	
	Number of Units			Weighted-Average Grant Date Fair Value	Number of Units			Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Units/Shares Non-Vested at 12/31/12	691,862		$	24.40	202,078		$	22.00	49,106	$ 23.61
Granted	316,162	(A)	$	25.89	74,570	(A)	$	26.73	5,940	$ 29.71
Modification	87,150	(B)	$	36.29	87,170	(B)	$	30.62	N/A	N/A
Vested	(355,078)		$	23.05	(118,350)		$	20.81	(30,242)	$ 22.57
Forfeited	(33,114)		$	24.96	(9,792)		$	23.34	(1,176)	$ 26.87
Units/Shares Non-Vested at 12/31/13	706,982		$	25.90	235,676		$	25.28	23,628	$ 26.30
Units/Shares Expected to Vest	633,808	(C)			209,938	(C)			23,628	

(A) For performance units, this represents the target number of performance units granted. Actual number of performance units earned, if any, is dependent upon performance and may range from 0 percent to 200 percent of the target.
(B) These amounts represent the performance unit grants previously based on earnings before interest, taxes, depreciation and amortization that were converted to performance units based on total shareholder return or earnings per share as a result of the formation of Enable.
(C) The intrinsic value of the performance units based on total shareholder return and earnings per share is $28.3 million and $5.6 million, respectively.

Fair Value of Vested Performance Units and Restricted Stock

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

Year ended December 31 *(In millions)*	**2013**	2012	2011
Performance units			
Total shareholder return	**$ 8.2**	$ 7.4	$ 7.4
Earnings per share	**4.9**	4.1	3.9
Restricted stock	**0.7**	0.7	1.0

Unrecognized Compensation Cost

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

December 31, 2013	Unrecognized Compensation Cost *(in millions)*	Weighted Average to be Recognized *(in years)*
Performance units		
Total shareholder return	$ 8.4	1.63
Earnings per share	1.8	1.49
Total performance units	10.2	
Restricted stock	0.2	1.63
Total	$ 10.4	

Stock Options

The Company last issued stock options in 2004 and as of December 31, 2006, all stock options were fully vested and expensed. All stock options have a contractual life of 10 years. A summary of the activity for the Company's stock options at December 31, 2013 and changes during 2013 are shown in the following table.

(dollars in millions)	Number of Options		Weighted-Average Exercise Price		Aggregate Intrinsic Value	Weighted-Average Remaining Contractual Term
Options Outstanding at 12/31/12	39,200	$	11.40			
Exercised	(39,200)	$	(11.40)	$	1.4	
Options Outstanding at 12/31/13	—	$	—	$	—	0.00 years
Options Fully Vested and Exercisable at 12/31/13	—	$	—	$	—	0.00 years

A summary of the activity for the Company's exercised stock options in 2013, 2012 and 2011 are shown in the following table.

Year ended December 31 *(In millions)*		**2013**		2012		2011
Intrinsic value (A)	**$**	**1.4**	$	2.0	$	2.2
Cash received from stock options exercised		**0.4**		0.8		1.3

(A) The difference between the market value on the date of exercise and the option exercise price.

8. Supplemental Cash Flow Information

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

Year ended December 31 *(In millions)*		**2013**		2012		2011
NON-CASH INVESTING AND FINANCING ACTIVITIES						
Installment payments for Tinker electric distribution system	**$**	**—**	$	10.6	$	—
Power plant long-term service agreement		**9.7**		—		1.7
Investment in Enable (Note 3)		**1,248.6**		—		—
SUPPLEMENTAL CASH FLOW INFORMATION						
Cash Paid During the Period for						
Interest (net of interest capitalized) (A)	**$**	**151.1**	$	161.3	$	138.9
Income taxes (net of income tax refunds)		**(1.1)**		(9.1)		4.7

(A) Net of interest capitalized of $5.4 million, $8.0 million and $19.1 million in 2013, 2012 and 2011, respectively.

9. Income Taxes

The items comprising income tax expense are as follows:

Year ended December 31 *(In millions)*	**2013**	2012	2011
Provision (Benefit) for Current Income Taxes			
Federal	**$ —**	$ (9.1)	$ (5.4)
State	**4.3**	0.5	0.1
Total Provision (Benefit) for Current Income Taxes	**4.3**	(8.6)	(5.3)
Provision for Deferred Income Taxes, net			
Federal	**154.4**	147.3	165.5
State	**(26.4)**	(1.5)	3.8
Total Provision for Deferred Income Taxes, net	**128.0**	145.8	169.3
Deferred Federal Investment Tax Credits, net	**(2.0)**	(2.1)	(3.3)
Total Income Tax Expense	**$ 130.3**	$ 135.1	$ 160.7

The Company files consolidated income tax returns in the U.S. Federal jurisdiction and various state jurisdictions. With few exceptions, the Company is no longer subject to U.S. Federal tax examinations by tax authorities for years prior to 2010 or state and local tax examinations by tax authorities for years prior to 2009. Income taxes are generally allocated to each company in the affiliated group based on its stand-alone taxable income or loss. Federal investment tax credits previously claimed on electric utility property have been deferred and are being amortized to income over the life of the related property. OG&E earns both Federal and Oklahoma state tax credits associated with production from its wind farms. In addition, OG&E and Enable earn Oklahoma state tax credits associated with their investments in electric generating and natural gas processing facilities which further reduce the Company's effective tax rate. The following schedule reconciles the statutory Federal tax rate to the effective income tax rate:

Year ended December 31	**2013**	2012	2011
Statutory Federal tax rate	**35.0 %**	35.0 %	35.0 %
Amortization of net unfunded deferred taxes	**0.6**	0.8	0.7
State income taxes, net of Federal income tax benefit	**0.4**	(0.1)	0.6
Federal investment tax credits, net	**(0.4)**	(0.4)	(0.7)
401(k) dividends	**(0.5)**	(0.5)	(0.5)
Income attributable to noncontrolling interest	**(0.3)**	(1.6)	(1.3)
Federal renewable energy credit (A)	**(7.2)**	(7.2)	(3.4)
Uncertain tax positions	**1.5**	—	—
Remeasurement of state deferred tax liabilities	**(4.1)**	—	—
Other	**(0.1)**	—	0.3
Effective income tax rate	**24.9 %**	26.0 %	30.7 %

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

The deferred tax provisions are recognized as costs in the ratemaking process by the commissions having jurisdiction over the rates charged by OG&E. The components of Deferred Income Taxes at December 31, 2013 and 2012, respectively, were as follows:

December 31 *(In millions)*	**2013**	2012
Current Deferred Income Tax Assets		
Net operating losses	**$ 180.1**	$ 152.4
Accrued liabilities	**22.3**	27.1
Federal tax credits	**8.0**	6.0
Accrued vacation	**4.7**	3.8
Uncollectible accounts	**0.7**	1.0
Total Current Deferred Income Tax Assets	**215.8**	190.3
Current Accrued Income Tax Liabilities		
Derivative instruments	**—**	(2.6)
Total Current Accrued Income Tax Liabilities	**—**	(2.6)
Current Deferred Income Tax Assets, net	**$ 215.8**	$ 187.7
Non-Current Deferred Income Tax Liabilities		
Accelerated depreciation and other property related differences	**$ 1,753.3**	$ 1,660.3
Investment in Enogex Holdings	**—**	638.0
Investment in Enable Midstream Partners	**630.5**	—
Company pension plan	**55.1**	52.4
Income taxes refundable to customers, net	**21.9**	21.2
Regulatory asset	**26.1**	18.8
Bond redemption-unamortized costs	**3.6**	4.0
Derivative instruments	**1.6**	1.5
Total Non-Current Deferred Income Tax Liabilities	**2,492.1**	2,396.2
Non-Current Deferred Income Tax Assets		
Federal tax credits	**(105.2)**	(69.6)
State tax credits	**(92.6)**	(83.7)
Postretirement medical and life insurance benefits	**(62.8)**	(57.6)
Regulatory liabilities	**(61.3)**	(71.4)
Asset retirement obligations	**(20.8)**	—
Net operating losses	**(18.8)**	(159.1)
Other	**(4.6)**	(4.5)
Deferred Federal investment tax credits	**(0.7)**	(1.5)
Total Non-Current Deferred Income Tax Assets	**(366.8)**	(447.4)
Non-Current Deferred Income Tax Liabilities, net	**$ 2,125.3**	$ 1,948.8

As of December 31, 2013, the Company has classified $7.8 million of unrecognized tax benefits as a reduction of deferred tax assets recorded. Management is currently unaware of any issues under review that could result in significant additional payments, accruals, or other material deviation from this amount.

Following is a reconciliation of the Company's total gross unrecognized tax benefits as of the years ended December 31, 2013, 2012, and 2011.

(Millions)	2013	2012	2011
Balance at January 1	$ —	$ —	$ —
Tax positions related to current year:			
Additions	2.7	—	—
Tax positions related to prior years:			
Additions	5.1	—	—
Balance at December 31	$ 7.8	$ —	$ —

Where applicable, the Company classifies income tax-related interest and penalties as interest expense and other operation and maintenance expense, respectively. During the year ended December 31, 2013, there were no income tax-related interest or penalties recorded with regard to uncertain tax positions. The total amount of unrecognized tax benefits that would impact the effective tax rate, if recognized, was $7.8 million as of December 31, 2013.

As previously reported, in January 2013, OG&E determined that a portion of certain Oklahoma investment tax credits previously recognized but not yet utilized may not be available for utilization in future years. During the first quarter of 2013, OG&E recorded a reserve of $7.8 million ($5.1 million after tax) related to a portion of the Oklahoma investment tax credits generated in years prior to 2013 but not yet utilized due to management's determination that it is more likely than not that it will be unable to utilize these credits. An additional reserve of $4.1 million ($2.7 million after tax) was established with regard to these credits generated in the current year.

Prior to 2013, the Company had a Federal tax operating loss primarily caused by the accelerated tax "bonus" depreciation provision contained within the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010 which allowed the Company to record a current income tax deduction for 100 percent of the cost of certain property placed into service in 2011 and 50 percent for certain property placed into service in 2012. During 2013, the Company began to utilize these net operating losses.

On January 2, 2013, the American Taxpayer Relief Act of 2012 was signed into law. Among other things, the law included an extension of bonus depreciation for one year for property generally placed in service before January 1, 2014. The impact of the new law was reflected in the Company's 2013 Consolidated Financial Statements as an increase in Deferred Tax Liabilities with a corresponding increase in Deferred Tax Assets related to the net operating loss.

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

Other

The Company sustained Federal and state tax operating losses through 2012 caused primarily by bonus depreciation and other book verses tax temporary differences. As a result, the Company had accrued Federal and state income tax benefits carrying into 2013. As the Company can no longer carry these losses back to prior periods, these losses are being carried forward for utilization in future years. In addition to the operating losses, the Company was unable to utilize the various tax credits that were generating during these years. These tax losses and credits are being carried as deferred tax assets and will be utilized in future periods. Under current law, the Company anticipates future taxable income will be sufficient to utilize all of the losses and credits before they begin to expire, accordingly no valuation allowance is considered necessary. The following table summarizes these carry forwards:

(In millions)	Carry Forward Amount	Deferred Tax Asset	Earliest Expiration Date
Net operating losses			
State operating loss	$ 893.6	$ 32.8	2030
Federal operating loss	474.6	166.1	2030
Federal tax credits	113.2	113.2	2029
State tax credits			
Oklahoma investment tax credits	106.1	69.0	N/A
Oklahoma capital investment board credits	7.3	7.3	N/A
Oklahoma zero emission tax credits	24.3	16.3	2020

Acquisition of the equity interest in Enable on May 1, 2013, is also expected to increase the Company's utilization of state net operating loss carryforwards. Under current tax law, the Company projects full utilization of all Federal operating losses in 2014 as well as partial utilization of State operating loss carryforwards. Accordingly, a current deferred tax asset of $180.1 million has been reflected on the balance sheet.

As a result of acquiring an equity interest in Enable, the Company has a lower effective tax rate in conjunction with the formation of Enable in states with lower state tax rates. Remeasurement of state deferred tax expense to reflect these lower rates reduced income tax expense for 2013 by $8.4 million. In addition, deferred tax adjustments related to the Company's deconsolidation of Enogex Holdings increased income tax expense for 2013 by $3.9 million.

During 2013, the Company recognized a $16.4 million reduction in deferred state income taxes, associated with a remeasurement of the accumulated deferred taxes related to the formation of an employment company within Enable.

10. Common Equity

Forward Stock Split

On May 16, 2013, the Company's Board of Directors approved a 2-for-1 forward stock split of the Company's common stock, effective July 1, 2013, which entitled each shareholder of record to receive two shares for every one share of Company stock owned by the shareholder. In connection with the stock split, an amendment to the Company's Articles of Incorporation was approved on May 16, 2013 which increased the number of authorized shares of common stock from 225 million to 450 million. All share and per share amounts presented within this Form 10-K reflect the effects of the stock split.

Automatic Dividend Reinvestment and Stock Purchase Plan

The Company issued 399,485 shares of common stock under its Automatic Dividend Reinvestment and Stock Purchase Plan in 2013 and received proceeds of $13.8 million. The Company may, from time to time, issue additional shares under its Automatic Dividend Reinvestment and Stock Purchase Plan to fund capital requirements or working capital needs. At December 31, 2013, there were 3,845,503 shares of unissued common stock reserved for issuance under the Company's Automatic Dividend Reinvestment and Stock Purchase Plan.

Earnings Per Share

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

(In millions)	**2013**	2012	2011
Net Income Attributable to OGE Energy	**$ 387.6**	$ 355.0	$ 342.9
Average Common Shares Outstanding			
Basic average common shares outstanding	**198.2**	197.1	195.8
Effect of dilutive securities:			
Contingently issuable shares (performance units)	**1.2**	1.0	2.7
Diluted average common shares outstanding	**199.4**	198.1	198.5
Basic Earnings Per Average Common Share Attributable to OGE Energy Common Shareholders	**$ 1.96**	$ 1.80	$ 1.75
Diluted Earnings Per Average Common Share Attributable to OGE Energy Common Shareholders	**$ 1.94**	$ 1.79	$ 1.73

11. Long-Term Debt

A summary of the Company's long-term debt is included in the Consolidated Statements of Capitalization. At December 31, 2013, the Company was in compliance with all of its debt agreements.

OG&E Industrial Authority Bonds

OG&E has tax-exempt pollution control bonds with optional redemption provisions that allow the holders to request repayment of the bonds on any business day. The bonds, which can be tendered at the option of the holder during the next 12 months, are as follows:

SERIES			DATE DUE	AMOUNT
				(In millions)
0.18%	-	0.34%	Garfield Industrial Authority, January 1, 2025	$ 47.0
0.10%	-	0.39%	Muskogee Industrial Authority, January 1, 2025	32.4
0.10%	-	0.30%	Muskogee Industrial Authority, June 1, 2027	56.0
Total (redeemable during next 12 months)				$ 135.4

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

Issuance of Long-Term Debt

On May 8, 2013, OG&E issued $250 million of 3.9% senior notes due May 1, 2043. The proceeds from the issuance were added to OG&E's general funds and were used to repay short-term debt, fund capital expenditures, general corporate expenses and for working capital purposes. OG&E expects to issue additional long-term debt from time to time when market conditions are favorable and when the need arises.

Long-Term Debt Maturities

Maturities of the Company's long-term debt during the next five years consist of $100.2 million, $0.2 million, $110.2 million, $125.1 million and $250.1 million in years 2014, 2015, 2016, 2017 and 2018, respectively.

The Company has previously incurred costs related to debt refinancings. Unamortized loss on reacquired debt is classified as a Non-Current Regulatory Asset, unamortized debt expense is classified as Deferred Charges and Other Assets and the unamortized premium and discount on long-term debt is classified as Long-Term Debt, respectively, in the Consolidated Balance Sheets and are being amortized over the life of the respective debt.

12. Short-Term Debt and Credit Facilities

The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The short-term debt balance was $439.6 million and $430.9 million at December 31, 2013 and 2012, respectively, at a weighted-average interest rate of 0.30 percent and 0.43 percent, respectively. The following table provides information regarding the Company's revolving credit agreements and available cash at December 31, 2013.

Entity	Aggregate Commitment	Amount Outstanding (A)	Weighted-Average Interest Rate	Maturity	
	(In millions)				
OGE Energy (B)	$ 750.0	$ 439.6	0.30% (D)	December 13, 2017	(E)
OG&E (C)	400.0	2.1	0.53% (D)	December 13, 2017	(E)
	1,150.0	441.7	0.30%		
Cash	6.8	N/A	N/A	N/A	
Total	$ 1,156.8	$ 441.7	0.30%		

(A) Includes direct borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit at December 31, 2013.
(B) This bank facility is available to back up OGE Energy's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility.
(C) This bank facility is available to back up OG&E's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility.
(D) Represents the weighted-average interest rate for the outstanding borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit.
(E) In December 2011, the Company and OG&E entered into unsecured five-year revolving credit agreements to total in the aggregate $1,150.0 million ($750.0 million for the Company and $400.0 million for OG&E). Each of the credit facilities contain an option, which may be exercised up to two times, to extend the term for an additional year, subject to consent of a specified percentage of the lenders. Effective July 29, 2013, the Company and OG&E utilized one of these one-year extensions, and received consent from all of the lenders, to extend the maturity of their credit agreements to December 13, 2017.

Effective May 1, 2013, Enable entered into a $1.4 billion, five-year senior unsecured revolving credit facility in accordance with the terms of the Master Formation Agreement and Enogex LLC's $400.0 million revolving credit facility was terminated.

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

OG&E must obtain regulatory approval from the FERC in order to borrow on a short-term basis. OG&E has the necessary regulatory approvals to incur up to $800 million in short-term borrowings at any one time for a two-year period beginning January 1, 2013 and ending December 31, 2014.

13. Retirement Plans and Postretirement Benefit Plans

Pension Plan and Restoration of Retirement Income Plan

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

It is the Company's policy to fund the Pension Plan on a current basis based on the net periodic pension expense as determined by the Company's actuarial consultants. During both 2013 and 2012, OGE Energy made contributions to its Pension Plan of $35 million to help ensure that the Pension Plan maintains an adequate funded status. Such contributions are intended to provide not only for benefits attributed to service to date, but also for those expected to be earned in the future. During 2014, OGE Energy expects to contribute up to $26 million to its Pension Plan. The expected contribution to the Pension Plan during 2014 would be a discretionary contribution, anticipated to be in the form of cash, and is not required to satisfy the minimum regulatory funding requirement specified by the Employee Retirement Income Security Act of 1974, as amended. OGE Energy could be required to make additional contributions if the value of its pension trust and postretirement benefit plan trust assets are adversely impacted by a major market disruption in the future.

In accordance with ASC Topic 715, "Compensation - Retirement Benefits," a one-time settlement charge is required to be recorded by an organization when lump sum payments or other settlements that relieve the organization from the responsibility for the pension benefit obligation during a plan year exceed the service cost and interest cost components of the organization's net periodic pension cost. During 2013, the Company experienced an increase in both the number of employees electing to retire and the amount of lump sum payments to be paid to such employees upon retirement. As a result, and based in part on the Company's historical experience regarding eligible employees who elect to retire in the last quarter of a particular year, the Company recorded pension settlement charges of $22.4 million in the fourth quarter of 2013, of which $17.0 million related to OG&E's Oklahoma jurisdiction and has been included in the pension tracker. The pension settlement charge did not require a cash outlay by the Company and did not increase the Company's total pension expense over time, as the charges were an acceleration of costs that otherwise would be recognized as pension expense in future periods.

The Company provides a Restoration of Retirement Income Plan to those participants in the Company's Pension Plan whose benefits are subject to certain limitations of the Code. Participants in the Restoration of Retirement Income Plan receive the same benefits that they would have received under the Company's Pension Plan in the absence of limitations imposed by the Federal tax laws. The Restoration of Retirement Income Plan is intended to be an unfunded plan.

The following table presents the status of the Company's Pension Plan and Restoration of Retirement Income Plan at December 31, 2013 and 2012. These amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which is recorded as a regulatory asset as discussed in Note 1) in the Company's Consolidated Balance Sheet. The amounts in Accumulated Other Comprehensive Loss and those recorded as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

	Pension Plan		Restoration of Retirement Income Plan	
December 31 *(In millions)*	**2013**	2012	**2013**	2012
Benefit obligations	**$ (658.1)**	$ (747.1)	**$ (14.0)**	$ (14.5)
Fair value of plan assets	**654.9**	626.0	**—**	—
Funded status at end of year	**$ (3.2)**	$ (121.1)	**$ (14.0)**	$ (14.5)

The following table summarizes the benefit payments the Company expects to pay related to its Pension Plan and Restoration of Retirement Income Plan. These expected benefits are based on the same assumptions used to measure the Company's benefit obligation at the end of the year and include benefits attributable to estimated future employee service.

(In millions)	Projected Benefit Payments
2014	$ 93.2
2015	82.0
2016	76.7
2017	71.7
2018	64.7
After 2018	270.1

Plan Investments, Policies and Strategies

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

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

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

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

The Company has retained an investment consultant responsible for the general investment oversight, analysis, monitoring investment guideline compliance and providing quarterly reports to certain of the Company's members and the Company's Investment Committee. The various investment managers used by the trust operate within the general operating objectives as established in the investment policy and within the specific guidelines established for each investment manager's respective portfolio.

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

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

Asset Class	Comparative Benchmark(s)
Core Fixed Income	Barclays Capital Aggregate Index
Interest Rate Sensitive Fixed Income	Barclays Capital Aggregate Index
Long Duration Fixed Income	Barclays Long Government/Credit
Equity Index	Standard & Poor's 500 Index
All-Cap Equity	Russell 3000 Index
	Russell 3000 Value Index
Mid-Cap Equity	Russell Midcap Index
	Russell Midcap Value Index
Small-Cap Equity	Russell 2000 Index
	Russell 2000 Value Index
International Equity	Morgan Stanley Capital Investment ACWI ex-US

The fixed income manager is expected to use discretion over the asset mix of the trust assets in its efforts to maximize risk-adjusted performance. Exposure to any single issuer, other than the U.S. government, its agencies, or its instrumentalities (which have no limits) is limited to five percent of the fixed income portfolio as measured by market value. At least 75 percent of the invested assets must possess an investment grade rating at or above Baa3 or BBB- by Moody's Investors Services, Standard & Poor's Ratings Services or Fitch Ratings. The portfolio may invest up to 10 percent of the portfolio's market value in convertible bonds as long as the securities purchased meet the quality guidelines. The purchase of any of the Company's equity, debt or other securities is prohibited.

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

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

Plan Investments

The following tables summarize the Pension Plan's investments that are measured at fair value on a recurring basis at December 31, 2013 and 2012. There were no Level 3 investments held by the Pension Plan at December 31, 2013 and 2012.

(In millions)	December 31, 2013	Level 1	Level 2
Common stocks			
U.S. common stocks	$ **236.8**	$ **236.8**	$ **—**
Foreign common stocks	**39.3**	**39.3**	**—**
U.S. Government obligations			
U.S. treasury notes and bonds (A)	**159.8**	**159.8**	**—**
Mortgage-backed securities	**50.3**	**—**	**50.3**
Bonds, debentures and notes (B)			
Corporate fixed income and other securities	**110.6**	**—**	**110.6**
Mortgage-backed securities	**22.3**	**—**	**22.3**
Commingled fund (C)	**29.2**	**—**	**29.2**
Common/collective trust (D)	**26.0**	**—**	**26.0**
Foreign government bonds	**4.0**	**—**	**4.0**
U.S. municipal bonds	**2.0**	**—**	**2.0**
Interest-bearing cash	**0.1**	**0.1**	**—**
Forward contracts			
Receivable (foreign currency)	**1.1**	**—**	**1.1**
Payable (foreign currency)	**(1.1)**	**—**	**(1.1)**
Total Plan investments	$ **680.4**	$ **436.0**	$ **244.4**
Receivable from broker for securities sold	**11.5**		
Interest and dividends receivable	**3.2**		
Payable to broker for securities purchased	**(40.2)**		
Total Plan assets	$ **654.9**		

(In millions)	December 31, 2012	Level 1	Level 2
Common stocks			
U.S. common stocks	$ 232.2	$ 232.2	$ —
Foreign common stocks	39.9	39.9	—
U.S. Government obligations			
U.S. treasury notes and bonds (A)	138.6	138.6	—
Mortgage-backed securities	55.8	—	55.8
Bonds, debentures and notes (B)			
Corporate fixed income and other securities	98.4	—	98.4
Mortgage-backed securities	13.5	—	13.5
Commingled fund (C)	34.9	—	34.9
Common/collective trust (D)	25.6	—	25.6
Foreign government bonds	3.9	—	3.9
U.S. municipal bonds	0.8	—	0.8
Interest-bearing cash	0.2	0.2	—
Preferred stocks (foreign)	—	—	—
Forward contracts			
Receivable (foreign currency)	0.4	—	0.4
Payable (foreign currency)	(0.4)	—	(0.4)
Total Plan investments	$ 643.8	$ 410.9	$ 232.9
Receivable from broker for securities sold	0.8		
Interest and dividends receivable	2.8		
Payable to broker for securities purchased	(21.4)		
Total Plan assets	$ 626.0		

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

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

(C) This category represents units of participation in a commingled fund that primarily invested in stocks of international companies and emerging markets.

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

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

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

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

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

Postretirement Benefit Plans

In addition to providing pension benefits, the Company provides certain medical and life insurance benefits for eligible retired members. Regular, full-time, active employees hired prior to February 1, 2000 whose age and years of credited service total or exceed 80 or have attained at least age 55 with 10 or more years of service at the time of retirement are entitled to postretirement medical benefits while employees hired on or after February 1, 2000 are not entitled to postretirement medical benefits. Eligible retirees must contribute such amount as the Company specifies from time to time toward the cost of coverage for postretirement benefits. The benefits are subject to deductibles, co-payment provisions and other limitations. OG&E charges to expense the postretirement benefit costs and includes an annual amount as a component of the cost-of-service in future ratemaking proceedings.

The Company's contribution to the medical costs for pre-65 aged eligible retirees are fixed at the 2011 level and the Company covers future annual medical inflationary cost increases up to five percent. Increases in excess of five percent annually are covered by the pre-65 aged retiree in the form of premium increases. The Company provides Medicare-eligible retirees and their Medicare-eligible spouses an annual fixed contribution to a Company-sponsored health reimbursement arrangement. Medicare-eligible retirees are able to purchase individual insurance policies supplemental to Medicare through a third-party administrator and use their health reimbursement arrangement funds for reimbursement of medical premiums and other eligible medical expenses.

Plan Investments

The following tables summarize the postretirement benefit plans investments that are measured at fair value on a recurring basis at December 31, 2013 and 2012. There were no Level 2 investments held by the postretirement benefit plans at December 31, 2013 and 2012.

(In millions)	December 31, 2013	Level 1	Level 3
Group retiree medical insurance contract (A)	**$ 53.1**	**$ —**	**$ 53.1**
Mutual funds investment			
U.S. equity investments	**7.9**	**7.9**	**—**
Money market funds investment	**0.4**	**0.4**	**—**
Total Plan investments	**$ 61.4**	**$ 8.3**	**$ 53.1**

(In millions)	December 31, 2012	Level 1	Level 3
Group retiree medical insurance contract (A)	$ 53.3	$ —	$ 53.3
Mutual funds investment			
U.S. equity investments	6.0	6.0	—
Money market funds investment	0.3	0.3	—
Total Plan investments	$ 59.6	$ 6.3	$ 53.3

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

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

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

Year ended December 31 *(In millions)*		**2013**
Group retiree medical insurance contract		
Beginning balance	**$**	**53.3**
Net unrealized gains related to instruments held at the reporting date		**(0.5)**
Interest income		**1.1**
Dividend income		**0.6**
Realized gains		**0.4**
Administrative expenses and charges		**(0.1)**
Claims paid		**(1.7)**
Ending balance	**$**	**53.1**

The following table presents the status of the Company's postretirement benefit plans at December 31, 2013 and 2012. These amounts have been recorded in Accrued Benefit Obligations with the offset in Accumulated Other Comprehensive Loss (except OG&E's portion which is recorded as a regulatory asset as discussed in Note 1) in the Company's Consolidated Balance Sheet. The amounts in Accumulated Other Comprehensive Loss and those recorded as a regulatory asset represent a net periodic benefit cost to be recognized in the Consolidated Statements of Income in future periods.

December 31 *(In millions)*		**2013**		2012
Benefit obligations	**$**	**(258.2)**	$	(301.0)
Fair value of plan assets		**61.4**		59.6
Funded status at end of year	**$**	**(196.8)**	$	(241.4)

The assumed health care cost trend rates have a significant effect on the amounts reported for postretirement medical benefit plans. Future health care cost trend rates are assumed to be 8.35 percent in 2014 with the rates trending downward to 4.48 percent by 2028. A one-percentage point change in the assumed health care cost trend rate would have the following effects:

ONE-PERCENTAGE POINT INCREASE

Year ended December 31 *(In millions)*		**2013**		2012		2011
Effect on aggregate of the service and interest cost components	**$**	**—**	$	—	$	—
Effect on accumulated postretirement benefit obligations		**0.1**		0.1		0.1

ONE-PERCENTAGE POINT DECREASE

Year ended December 31 *(In millions)*		**2013**		2012		2011
Effect on aggregate of the service and interest cost components	**$**	**0.1**	$	0.1	$	0.1
Effect on accumulated postretirement benefit obligations		**0.6**		0.9		0.6

Medicare Prescription Drug, Improvement and Modernization Act of 2003

The Medicare Prescription Drug, Improvement and Modernization Act of 2003 expanded coverage for prescription drugs. The following table summarizes the gross benefit payments the Company expects to pay related to its postretirement benefit plans, including prescription drug benefits.

(In millions)	Gross Projected Postretirement Benefit Payments
2014	$ 15.5
2015	16.1
2016	16.7
2017	17.2
2018	17.7
After 2018	90.7

Obligations and Funded Status

The following table presents the status of the Company's Pension Plan, the Restoration of Retirement Income Plan and the postretirement benefit plans for 2013 and 2012. The benefit obligation for the Company's Pension Plan and the Restoration of Retirement Income Plan represents the projected benefit obligation, while the benefit obligation for the postretirement benefit plans represents the accumulated postretirement benefit obligation. The accumulated postretirement benefit obligation for the Company's Pension Plan and Restoration of Retirement Income Plan differs from the projected benefit obligation in that the former includes no assumption about future compensation levels. The accumulated postretirement benefit obligation for the Pension Plan and the Restoration of Retirement Income Plan at December 31, 2013 was $623.4 million and $12.9 million, respectively. The accumulated postretirement benefit obligation for the Pension Plan and the Restoration of Retirement Income Plan at December 31, 2012 was $705.2 million and $12.7 million, respectively. The details of the funded status of the Pension Plan, the Restoration of Retirement Income Plan and the postretirement benefit plans and the amounts included in the Consolidated Balance Sheets are as follows:

December 31 *(In millions)*	Pension Plan 2013	Pension Plan 2012	Restoration of Retirement Income Plan 2013	Restoration of Retirement Income Plan 2012	Postretirement Benefit Plans 2013	Postretirement Benefit Plans 2012
Change in Benefit Obligation						
Beginning obligations	**$ (747.1)**	$ (697.7)	**$ (14.5)**	$ (13.3)	**$ (301.0)**	$ (280.6)
Service cost	**(19.0)**	(17.9)	**(1.2)**	(1.0)	**(4.3)**	(4.1)
Interest cost	**(26.7)**	(30.1)	**(0.5)**	(0.6)	**(10.3)**	(11.9)
Plan amendments	**—**	—	**—**	—	**—**	—
Plan settlements	**67.5**	—	**—**	—	**—**	—
Participants' contributions	**—**	—	**—**	—	**(3.4)**	(3.5)
Medicare subsidies received	**—**	—	**—**	—	**—**	(0.5)
Actuarial gains (losses)	**53.0**	(61.4)	**2.0**	(1.8)	**46.7**	(12.9)
Benefits paid	**14.2**	60.0	**0.2**	2.2	**14.1**	12.5
Ending obligations	**$ (658.1)**	$ (747.1)	**$ (14.0)**	$ (14.5)	**$ (258.2)**	$ (301.0)
Change in Plans' Assets						
Beginning fair value	**$ 626.0**	$ 589.8	**$ —**	$ —	**$ 59.6**	$ 61.0
Actual return on plans' assets	**75.6**	61.2	**—**	—	**3.7**	4.5
Employer contributions	**35.0**	35.0	**0.2**	2.2	**8.8**	2.6
Plan settlements	**(67.5)**	—	**—**	—	**—**	—
Participants' contributions	**—**	—	**—**	—	**3.4**	3.5
Medicare subsidies received	**—**	—	**—**	—	**—**	0.5
Benefits paid	**(14.2)**	(60.0)	**(0.2)**	(2.2)	**(14.1)**	(12.5)
Ending fair value	**$ 654.9**	$ 626.0	**$ —**	$ —	**$ 61.4**	$ 59.6
Funded status at end of year	**$ (3.2)**	$ (121.1)	**$ (14.0)**	$ (14.5)	**$ (196.8)**	$ (241.4)

Net Periodic Benefit Cost

Year ended December 31 *(In millions)*	Pension Plan 2013	Pension Plan 2012	Pension Plan 2011	Restoration of Retirement Income Plan 2013	Restoration of Retirement Income Plan 2012	Restoration of Retirement Income Plan 2011	Postretirement Benefit Plans 2013	Postretirement Benefit Plans 2012	Postretirement Benefit Plans 2011
Service cost	**$ 19.0**	$ 17.9	$ 17.6	**$ 1.2**	$ 1.0	$ 1.0	**$ 4.3**	$ 4.1	$ 3.5
Interest cost	**26.7**	30.1	33.3	**0.5**	0.6	0.6	**10.3**	11.9	12.5
Expected return on plan assets	**(48.4)**	(46.0)	(45.5)	**—**	—	—	**(2.5)**	(3.0)	(5.1)
Amortization of transition obligation	**—**	—	—	**—**	—	—	**—**	2.7	2.7
Amortization of net loss	**26.5**	23.8	19.2	**0.4**	0.4	0.4	**21.5**	20.6	18.3
Amortization of unrecognized prior service cost (A)	**1.8**	2.2	2.4	**0.3**	0.7	0.7	**(16.5)**	(16.5)	(16.5)
Settlement	**22.4**	—	—	**—**	0.9	—	**—**	—	—
Total net periodic benefit cost	**48.0**	28.0	27.0	**2.4**	3.6	2.7	**17.1**	19.8	15.4
Less: Amount paid by unconsolidated affiliates	**5.9**	—	—	**0.1**	—	—	**1.5**	—	—
Net periodic benefit cost (B)	**$ 42.1**	$ 28.0	$ 27.0	**$ 2.3**	$ 3.6	$ 2.7	**$ 15.6**	$ 19.8	$ 15.4

(A) Unamortized prior service cost is amortized on a straight-line basis over the average remaining service period to the first eligibility age of participants who are expected to receive a benefit and are active at the date of the plan amendment.

(B) In addition to the $60.0 million, $51.4 million and $45.1 million and of net periodic benefit cost recognized in 2013, 2012 and 2011, respectively, the Company recognized the following:

- an increase in pension expense in 2013, 2012 and 2011 of $5.8 million, $8.3 million and $10.8 million, respectively, to maintain the allowable amount to be recovered for pension expense in the Oklahoma jurisdiction, which are included in the Pension tracker regulatory asset or liability (see Note 1); and
- an increase in postretirement medical expense in 2013, 2012 and 2011 of $0.6 million, $0.8 million and $3.5 million, respectively, to maintain the allowable amount to be recovered for postretirement medical expense in the Oklahoma jurisdiction which are included in the Pension tracker regulatory asset or liability (see Note 1);
- a deferral of pension expense in 2013 of $17.0 million related to the pension settlement charge of $22.4 million, in accordance with the Oklahoma pension tracker.

The capitalized portion of the net periodic pension benefit cost was $5.7 million, $6.5 million and $6.1 million at December 31, 2013, 2012 and 2011, respectively. The capitalized portion of the net periodic postretirement benefit cost was $3.5 million, $5.5 million and $3.8 million at December 31, 2013, 2012 and 2011, respectively.

Rate Assumptions

	Pension Plan and Restoration of Retirement Income Plan			Postretirement Benefit Plans		
Year ended December 31	**2013**	2012	2011	**2013**	2012	2011
Discount rate	**4.60%**	3.70%	4.50%	**4.60%**	3.60%	4.50%
Rate of return on plans' assets	**8.00%**	8.00%	8.00%	**4.00%**	4.00%	6.50%
Compensation increases	**4.20%**	4.20%	4.40%	**N/A**	N/A	N/A
Assumed health care cost trend:						
Initial trend	**N/A**	N/A	N/A	**8.35%**	8.55%	8.75%
Ultimate trend rate	**N/A**	N/A	N/A	**4.48%**	4.48%	4.48%
Ultimate trend year	**N/A**	N/A	N/A	**2028**	2028	2028

N/A - not applicable

The overall expected rate of return on plan assets assumption remained at 8.00 percent in 2012 and 2013 in determining net periodic benefit cost due to recent returns on the Company's long-term investment portfolio. The rate of return on plan assets assumption is the average long-term rate of earnings expected on the funds currently invested and to be invested for the purpose of providing benefits specified by the Pension Plan or postretirement benefit plans. This assumption is reexamined at least annually and updated as necessary. The rate of return on plan assets assumption reflects a combination of historical return analysis, forward-looking return expectations and the plans' current and expected asset allocation.

Post-Employment Benefit Plan

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

The post-employment benefit obligation is determined by an actuary on a basis similar to the accumulated postretirement benefit obligation. The estimated future medical benefits are projected to grow with expected future medical cost trend rates and are discounted for interest at the discount rate and for the probability that the participant will discontinue receiving benefits from the Company's Group Long-Term Disability Plan due to death, recovery from disability, or eligibility for retiree medical benefits. The Company's post-employment benefit obligation was $1.6 million and $2.6 million at December 31, 2013 and 2012, respectively.

401(k) Plan

The Company provides a 401(k) Plan. Each regular full-time employee of the Company or a participating affiliate is eligible to participate in the 401(k) Plan immediately. All other employees of the Company or a participating affiliate are eligible to become participants in the 401(k) Plan after completing one year of service as defined in the 401(k) Plan. Participants may contribute each pay period any whole percentage between two percent and 19 percent of their compensation, as defined in the 401(k) Plan, for that pay period. Participants who have attained age 50 before the close of a year are allowed to make additional contributions referred to as "Catch-Up Contributions," subject to certain limitations of the Code. Participants may designate, at their discretion, all or any portion of their contributions as: (i) a before-tax contribution under Section 401(k) of the Code subject to the limitations thereof; or (ii) a contribution made on an after-tax basis. The 401(k) Plan also includes an eligible automatic contribution arrangement and provides for a qualified default investment alternative consistent with the U.S. Department of Labor regulations. Participants may elect, in accordance with the 401(k) Plan procedures, to have his or her future salary deferral rate to be automatically increased annually on a date and in an amount as specified by the participant in such election.

No Company contributions are made with respect to a participant's Catch-Up Contributions, rollover contributions, or with respect to a participant's contributions based on overtime payments, pay-in-lieu of overtime for exempt personnel, special lump-sum recognition awards and lump-sum merit awards included in compensation for determining the amount of participant contributions. Once made, the Company's contribution may be directed to any available investment option in the 401(k) Plan. The Company match contributions vest over a three-year period. After two years of service, participants become 20 percent vested in their Company contribution account and become fully vested on completing three years of service. In addition, participants fully vest when they are eligible for normal or early retirement under the Pension Plan, in the event of their termination due to death or permanent disability or upon attainment of age 65 while employed by the Company or its affiliates. The Company contributed $14.2 million, $13.4 million and $12.3 million in 2013, 2012 and 2011, respectively, to the 401(k) Plan.

Deferred Compensation Plan

The Company provides a nonqualified deferred compensation plan which is intended to be an unfunded plan. The plan's primary purpose is to provide a tax-deferred capital accumulation vehicle for a select group of management, highly compensated employees and non-employee members of the Board of Directors of the Company and to supplement such employees' 401(k) Plan contributions as well as offering this plan to be competitive in the marketplace.

Eligible employees who enroll in the plan have the following deferral options: (i) eligible employees may elect to defer up to a maximum of 70 percent of base salary and 100 percent of annual bonus awards or (ii) eligible employees may elect a deferral percentage of base salary and bonus awards based on the deferral percentage elected for a year under the 401(k) Plan with such deferrals to start when maximum deferrals to the qualified 401(k) Plan have been made because of limitations in that plan. Eligible directors who enroll in the plan may elect to defer up to a maximum of 100 percent of directors' meeting fees and annual retainers. The Company matches employee (but not non-employee director) deferrals to make up for any match lost in the 401(k) Plan because of deferrals to the deferred compensation plan, and to allow for a match that would have been made under the 401(k) Plan on that portion of either the first six percent of total compensation or the first five percent of total compensation, depending on the option the participant elected under the choice provided to eligible employees in the qualified 401(k) Plan discussed above, deferred that exceeds the limits allowed in the 401(k) Plan. Matching credits vest based on years of service, with full vesting after three years or, if earlier, on retirement, disability, death, a change in control of the Company or termination of the plan. Deferrals, plus any Company match, are credited to a recordkeeping account in the participant's name. Earnings on the deferrals are indexed to the assumed investment funds selected by the participant. In 2013, those investment options included a Company Common Stock fund, whose value was determined based on the stock price of the Company's Common Stock. The Company accounts for the contributions related to the Company's executive officers in this plan as Accrued Benefit Obligations and the Company accounts for the contributions related to the Company's directors in this plan as Other Deferred Credits and Other Liabilities in the Consolidated Balance Sheets. The investment associated with these contributions is accounted for as Other Property and Investments in the Consolidated Balance Sheets. The appreciation of these investments is accounted for as Other Income and the increase in the liability under the plan is accounted for as Other Expense in the Consolidated Statements of Income.

Supplemental Executive Retirement Plan

The Company provides a supplemental executive retirement plan in order to attract and retain lateral hires or other executives designated by the Compensation Committee of the Company's Board of Directors who may not otherwise qualify for a sufficient level of benefits under the Company's Pension Plan and Restoration of Retirement Income Plan. The supplemental executive retirement plan is intended to be an unfunded plan and not subject to the benefit limitations of the Code.

14. Report of Business Segments

Prior to May 1, 2013, the Company's business was divided into three segments as follows: (i) electric utility, which is engaged in the generation, transmission, distribution and sale of electric energy, (ii) natural gas transportation and storage and (iii) natural gas gathering and processing. On March 14, 2013, OGE Energy entered into a Master Formation Agreement with the ArcLight group and CenterPoint Energy, Inc., pursuant to which OGE Energy, the ArcLight Group and CenterPoint Energy, Inc., agreed to form Enable Midstream Partners to own and operate the midstream businesses of OGE Energy and CenterPoint that will initially be structured as a private limited partnership. The transaction closed on May 1, 2013. As a result, effective May 1, 2013, OGE Energy deconsolidated its interest in Enogex Holdings LLC and began accounting for its interest in Enable using the equity method of accounting. The Company's business is now divided into two segments for financial reporting purposes as follows: (i) electric utility and (ii) natural gas midstream operations. The former natural gas transportation and storage segment and natural gas gathering and processing segment have been combined into the natural gas midstream operations segment and have been restated for all prior periods presented. Equity in earnings of unconsolidated affiliates in the natural gas midstream operations segment includes OGE Energy's equity interest in Enable from May 1, 2013 through December 31, 2013. Operating income for the natural gas midstream operations segment represents results of operations for Enogex Holdings LLC through April 30, 2013. Investment in unconsolidated affiliates in the natural gas midstream operations segment represents OGE Energy's investment in Enable at December 31, 2013. Other Operations primarily includes the operations of the holding company. Intersegment revenues are recorded at prices comparable to those of unaffiliated customers and are affected by regulatory considerations. In reviewing its segment operating results, the Company focuses on operating income and equity in earnings of unconsolidated affiliates as its measure of segment profit and loss, and, therefore, has presented this information below. The following tables summarize the results of the Company's business segments for the years ended December 31, 2013, 2012 and 2011.

2013	Electric Utility	Natural Gas Midstream Operations	Other Operations	Eliminations	Total
(In millions)					
Operating revenues	**$ 2,262.2**	**$ 630.4**	**$ —**	**$ (24.9)**	**$ 2,867.7**
Cost of sales	**965.9**	**489.0**	**—**	**(26.0)**	**1,428.9**
Other operation and maintenance	**438.8**	**60.9**	**(10.5)**	**—**	**489.2**
Depreciation and amortization	**248.4**	**36.8**	**12.1**	**—**	**297.3**
Taxes other than income	**83.8**	**10.5**	**4.5**	**—**	**98.8**
Operating income (loss)	**$ 525.3**	**$ 33.2**	**$ (6.1)**	**$ 1.1**	**$ 553.5**
Equity in earnings of unconsolidated affiliates	**$ —**	**$ 101.9**	**$ —**	**$ —**	**$ 101.9**
Investment in unconsolidated affiliates (at historical cost)	**$ —**	**$ 1,298.8**	**$ —**	**$ —**	**$ 1,298.8**
Total assets	**$ 7,694.9**	**$ 1,348.6**	**$ 216.2**	**$ (125.0)**	**$ 9,134.7**
Capital expenditures	**$ 797.6**	**$ 181.5**	**$ 11.5**	**$ —**	**$ 990.6**

2012	Electric Utility	Natural Gas Midstream Operations	Other Operations	Eliminations	Total
(In millions)					
Operating revenues	$ 2,141.2	$ 1,608.6	$ —	$ (78.6)	$ 3,671.2
Cost of sales	879.1	1,120.1	—	(80.5)	1,918.7
Other operation and maintenance	446.3	172.9	(17.7)	—	601.5
Depreciation and amortization	248.7	108.8	13.5	—	371.0
Impairment of assets	—	0.4	—	—	0.4
Gain on insurance proceeds	—	(7.5)	—	—	(7.5)
Taxes other than income	77.7	28.3	4.2	—	110.2
Operating income (loss)	$ 489.4	$ 185.6	$ —	$ 1.9	$ 676.9
Total assets	$ 7,222.4	$ 2,681.3	$ 242.6	$ (224.1)	$ 9,922.2
Capital expenditures	$ 704.4	$ 506.5	$ 18.3	$ —	$ 1,229.2

2011	Electric Utility	Natural Gas Midstream Operations	Other Operations	Eliminations	Total
(In millions)					
Operating revenues	$ 2,211.5	$ 1,787.1	$ —	$ (82.7)	$ 3,915.9
Cost of sales	1,013.5	1,346.6	—	(82.2)	2,277.9
Other operation and maintenance	436.0	162.5	(17.3)	—	581.2
Depreciation and amortization	216.1	77.6	13.4	—	307.1
Impairment of assets	—	6.3	—	—	6.3
Gain on insurance proceeds	—	(3.0)	—	—	(3.0)
Taxes other than income	73.6	22.0	4.1	—	99.7
Operating income (loss)	$ 472.3	$ 175.1	$ (0.2)	$ (0.5)	$ 646.7
Total assets	$ 6,620.9	$ 2,289.0	$ 155.0	$ (158.9)	$ 8,906.0
Capital expenditures	$ 844.5	$ 612.5	$ 13.8	$ —	$ 1,470.8

15. Commitments and Contingencies

Operating Lease Obligations

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

Year ended December 31 *(In millions)*	2014	2015	2016	2017	2018	After 2018	Total
Operating lease obligations							
Railcars	$ 3.8	$ 3.1	$ 27.3	$ —	$ —	$ —	$ 34.2
Wind farm land leases	2.1	2.1	2.1	2.4	2.4	48.8	59.9
OGE Energy noncancellable operating lease	0.8	0.8	0.8	0.8	0.7	—	3.9
Total operating lease obligations	$ 6.7	$ 6.0	$ 30.2	$ 3.2	$ 3.1	$ 48.8	$ 98.0

Payments for operating lease obligations were $8.8 million, $14.2 million and $10.4 million for the years ended December 31, 2013, 2012 and 2011, respectively.

OG&E Railcar Lease Agreement

OG&E has a noncancellable operating lease with purchase options, covering 1,389 coal rotary gondola railcars to transport coal from Wyoming to OG&E's coal-fired generation units. Rental payments are charged to Fuel Expense and are recovered through OG&E's tariffs and fuel adjustment clauses. On December 15, 2010, OG&E renewed the lease agreement effective February 1, 2011. At the end of the new lease term, which is February 1, 2016, OG&E has the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chooses not to purchase the railcars or renew the lease agreement and the actual fair value of the railcars is less than the stipulated fair market value, OG&E would be responsible for the difference in those values up to a maximum of $22.8 million. OG&E is also required to maintain all of the railcars it has under the operating lease and has entered into an agreement with a non-affiliated company to furnish this maintenance.

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 has a unilateral right to terminate this lease upon a 6-month notice effective April 2015 and April 2016.

OG&E Wind Farm Land Lease Agreements

OG&E has wind farm land operating leases for its Centennial, OU Spirit and Crossroads wind farms expiring at various dates. The Centennial lease has rent escalations which increase annually based on the Consumer Price Index. The OU Spirit and Crossroads leases have rent escalations which increase after five and 10 years. Although the leases are cancellable, OG&E is required to make annual lease payments as long as the wind turbines are located on the land. OG&E does not expect to terminate the leases until the wind turbines reach the end of their economic life.

OGE Energy Noncancellable Operating Lease

On August 29, 2012, OGE Energy executed a five-year lease agreement for office space from September 1, 2013 to August 31, 2018. This lease has rent escalations which increase after five-years and allows for leasehold improvements.

OGE Holdings Noncancellable Operating Lease

As a result of the formation of Enable Midstream Partners on May 1, 2013 and the Company's deconsolidation of Enogex Holdings, the Company has no obligations included in its Consolidated Financial Statements at December 31, 2013 under OGE Holdings' noncancellable lease obligations previously disclosed in the Company's 2012 Form 10-K.

Other Purchase Obligations and Commitments

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

(In millions)	2014	2015	2016	2017	2018	Total
Other purchase obligations and commitments						
Cogeneration capacity and fixed operation and maintenance payments	$ 85.1	$ 82.7	$ 81.9	$ 79.6	$ 77.0	$ 406.3
Expected cogeneration energy payments	61.1	60.9	75.7	81.5	87.4	366.6
Minimum fuel purchase commitments	451.8	451.8	368.5	385.1	—	1,657.2
Expected wind purchase commitments	58.0	58.9	59.8	60.8	59.5	297.0
Long-term service agreement commitments	70.5	2.8	2.5	2.6	19.1	97.5
Total other purchase obligations and commitments	$ 726.5	$ 657.1	$ 588.4	$ 609.6	$ 243.0	$ 2,824.6

Public Utility Regulatory Policy Act of 1978

At December 31, 2013, OG&E has QF contracts having terms of 15 to 32 years. These contracts were entered into pursuant to the Public Utility Regulatory Policy Act of 1978. Stated generally, the Public Utility Regulatory Policy Act of 1978 and the regulations thereunder promulgated by the FERC require OG&E to purchase power generated in a manufacturing process from a QF. The rate for such power to be paid by OG&E was approved by the OCC. The rate generally consists of two components: one is a rate for actual electricity purchased from the QF by OG&E; the other is a capacity charge, which OG&E must pay the QF for having the capacity available. However, if no electrical power is made available to OG&E for a period of time (generally three months), OG&E's obligation to pay the capacity charge is suspended. The total cost of cogeneration payments is recoverable in rates from customers. For the 320 MW AES-Shady Point, Inc. QF contract and the 120 MW PowerSmith Cogeneration Project, L.P. QF contract, OG&E purchases 100 percent of the electricity generated by the QFs.

For the years ended December 31, 2013, 2012 and 2011, OG&E made total payments to cogenerators of $134.8 million, $135.1 million and $140.7 million, respectively, of which $74.4 million, $77.1 million and $78.0 million, respectively, represented capacity payments. All payments for purchased power, including cogeneration, are included in the Consolidated Statements of Income as Cost of Sales.

OG&E Minimum Fuel Purchase Commitments

OG&E purchased necessary fuel supplies of coal and natural gas for its generating units of $657.3 million, $585.6 million and $647.6 million for the years ended December 31, 2013, 2012 and 2011, respectively. OG&E has coal contracts for purchases from through December 2016. OG&E has entered into multiple month term natural gas contracts for 31.5 percent of its 2014 annual forecasted natural gas requirements. Additional gas supplies to fulfill OG&E's remaining 2014 natural gas requirements will be acquired through additional requests for proposal in early to mid-2014, along with monthly and daily purchases, all of which are expected to be made at market prices.

OG&E Wind Purchase Commitments

OG&E's current wind power portfolio includes: (i) the 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.

The following table summarizes OG&E's wind power purchases for the years ended December 31, 2013, 2012 and 2011.

Year ended December 31 *(In millions)*	**2013**	2012	2011
CPV Keenan	**$ 30.9**	$ 25.1	$ 24.5
Edison Mission Energy	**20.6**	20.2	8.5
FPL Energy	**3.3**	3.4	3.7
NextEra Energy	**7.2**	0.8	—
Total wind power purchased	**$ 62.0**	$ 49.5	$ 36.7

OG&E Long-Term Service Agreement Commitments

OG&E has a long-term parts and service maintenance contract for the upkeep of the McClain Plant. The existing contract will expire on January 1, 2015. In May 2013, a new contract was signed that is expected to run for the earlier of 128,000 factored-fired hours or 3,600 factored-fired starts. Based on historical usage and current expectations for future usage, this contract is expected to run until 2030. The contract requires payments based on both a fixed and variable cost component, depending on how much the McClain Plant is used.

OG&E has a long-term parts and service maintenance contract for the upkeep of the Redbud Plant. In March 2013, the contract was amended to extend the contract coverage for an additional 24,000 factored-fired hours resulting in a maximum of the earlier of 144,000 factored-fired hours or 4,500 factored-fired starts. Based on historical usage and current expectations for future usage, this contract is expected to run until 2031. The contract requires payments based on both a fixed and variable cost component, depending on how much the Redbud Plant is used.

Enogex Energy Resources LLC Commitments

As a result of the formation of Enable on May 1, 2013 and the Company's deconsolidation of Enogex Holdings, the Company has no obligations included in its Consolidated Financial Statements at December 31, 2013 under OGE Holdings' noncancellable lease obligations previously disclosed in the Company's 2012 Form 10-K.

OG&E Wind Energy Purchased Power Lawsuit

In 2009, OG&E entered into a wind energy purchase power agreement with CPV Keenan for the purchase of all the energy output from its 150 MW wind farm in Woodward County, Oklahoma. In August of 2013, CPV Keenan filed suit against OG&E for the non-payment of curtailment charges. In December 2013, the Company settled its current case with CPV Keenan and recorded additional purchased power expense of $4.3 million, which will be recovered through the fuel adjustment clause.

Enable Gas Transportation and Storage Agreement

OG&E contracts with Enable for gas transportation and storage services. The stated term of this contract expired April 30, 2009, but remained in effect from year-to-year thereafter. On January 31, 2014, in anticipation of entering into a new, five-year contract, OG&E provided written notice of termination of the contract, effective April 30, 2014. Negotiations regarding the new contract are ongoing, and there can be no assurance that the new contract will be agreed upon, or if agreed upon, that the terms of the new contract will be as favorable to us as the expiring contract.

Environmental Laws and Regulations

The activities of OG&E are subject to stringent and complex Federal, state and local laws and regulations governing environmental protection relating to air quality, water quality, waste management, wildlife conservation and natural resources. These laws and regulations can restrict or impact business activities in many ways, such as restricting the way it can handle or dispose of its wastes, requiring remedial action to mitigate environmental issues that may be caused by its operations or that are attributable to former operators, requiring changes in operations and requiring the installation and operation of pollution control equipment. Failure to comply with these laws and regulations could result in the assessment of administrative, civil and criminal penalties, the imposition of remedial requirements and the issuance of orders enjoining future operations.

Environmental regulation can increase the cost of planning, design, initial installation and operation of OG&E's facilities. Historically, OG&E's total expenditures for environmental control facilities and for remediation have not been significant in relation to its consolidated financial position or results of operations. The Company believes, however, that it is reasonably likely that the trend in environmental legislation and regulations will continue towards more restrictive standards. Compliance with these standards is expected to increase the cost of conducting business. Management continues to evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

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

Federal Clean Air Act New Source Review Litigation

As previously reported, in July 2008, OG&E received a request for information from the EPA regarding Federal Clean Air Act compliance at OG&E's Muskogee and Sooner generating plants. In recent years, the EPA has issued similar requests to numerous other electric utilities seeking to determine whether various maintenance, repair and replacement projects should have required permits under the Federal Clean Air Act's new source review process. In January 2012, OG&E received a supplemental request for an update of the previously provided information and for some additional information not previously requested. On May 1, 2012, OG&E responded to the EPA's supplemental request for information. On April 26, 2011, the EPA issued a notice of violation alleging that 13 projects occurred at OG&E's Muskogee and Sooner generating plants between 1993 and 2006 without the required new source review permits. The notice of violation also alleges that OG&E's visible emissions at its Muskogee and Sooner generating plants are not in accordance with applicable new source performance standards.

In March 2013, the DOJ informed OG&E that it was prepared to initiate enforcement litigation concerning the matters identified in the notice of violation. OG&E subsequently met with EPA and DOJ representatives regarding the notice of violation and proposals for resolving the matter without litigation. On July 8, 2013, the United States, at the request of the EPA, filed a complaint for declaratory relief against OG&E in United States District Court for the Western District of Oklahoma (Case No. CIV-13-690-D) alleging that OG&E did not follow the Federal Clean Air Act procedures for projecting emission increases attributable to eight projects that occurred between 2003 and 2006. This complaint seeks to have OG&E submit a new assessment of whether the projects were likely to result in a significant emissions increase. The Sierra Club has intervened in this proceeding and has asserted claims for declaratory relief that are similar to those requested by the United States. OG&E expects to vigorously defend against these claims, but OG&E cannot predict the outcome of such litigation. On August 12, 2013, the Sierra Club filed a complaint against OG&E in the United States District Court for the Eastern District of Oklahoma (Case No. 13-CV-00356) alleging that OG&E modifications made at Unit 6 of the Muskogee generating plant in 2008 were made without obtaining a prevention of significant deterioration permit and that the plant has exceeded emissions limits for opacity and particulate matter. The Sierra Club seeks a permanent injunction preventing OG&E from operating the Muskogee generating plant. At this time, OG&E continues to believe that it has acted in compliance with the Federal Clean Air Act.

If OG&E does not prevail in these proceedings and if a new assessment of the projects were to conclude that they caused a significant emissions increase, the EPA and the Sierra Club could seek to require OG&E to install additional pollution control equipment, including scrubbers, baghouses and selective catalytic reduction systems with capital costs in excess of $1.0 billion and pay fines and significant penalties as a result of the allegations in the notice of violation. Section 113 of the Federal Clean Air Act (along with the Federal Civil Penalties Inflation Adjustment Act of 1996) provides for civil penalties as much as $37,500 per day for each violation. The cost of any required pollution control equipment could also be significant. OG&E cannot predict at this time whether it will be legally required to incur any of these costs.

Other

In the normal course of business, the Company is confronted with issues or events that may result in a contingent liability. These generally relate to lawsuits 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 otherwise stated above, in Note 16 below, in Item 3 of Part I and under "Environmental Laws and Regulations" in Item 7 of Part II of this Form 10-K, 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.

16. Rate Matters and Regulation

Regulation and Rates

OG&E's retail electric tariffs are regulated by the OCC in Oklahoma and by the APSC in Arkansas. The issuance of certain securities by OG&E is also regulated by the OCC and the APSC. OG&E's wholesale electric tariffs, 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 2013, 85 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight percent to the APSC and seven 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

Crossroads Wind Farm

As previously reported, OG&E signed memoranda of understanding in February 2010 for approximately 197.8 megawatts 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 megawatts. 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 April 15, 2013, the APSC issued an order authorizing OG&E to recover the Arkansas portion of the cost to construct the Crossroads wind farm, effective retroactively to August 1, 2012. The costs are being recovered through the Energy Cost Recovery Rider.

Fuel Adjustment Clause Review for Calendar Year 2011

The OCC routinely reviews the costs recovered from customers through OG&E’s fuel adjustment clause. 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 information and documents in response to the OCC's application 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. On April 9, 2013, the OCC administrative law judge recommended that the OCC find that for the calendar year 2011 OG&E's electric generation, purchased power and fuel procurement processes and costs were prudent. On June 18, 2013, the OCC issued an order approving the administrative law judge’s recommendation.

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. On May 29, 2013, the Governor signed House Bill 1932 into law which establishes a right of first refusal for Oklahoma incumbent transmission owners, including OG&E, to build new transmission projects with voltages under 300 kilovolts that interconnect to those incumbent entities' existing facilities. OG&E believes this law is consistent with the language of Order No. 1000.

On July 18, 2013, the FERC issued an order on the SPP's Order No. 1000 compliance filing. This order accepted in part and rejected in part the SPP's plan for complying with Order No. 1000. The FERC rejected the SPP's plan to retain the right of first refusal for projects that would operate between 100 kilovolts and 300 kilovolts. However, the FERC clarified that a right of first refusal was appropriate in certain circumstances. It is not clear how the FERC's order will relate to the recently enacted Oklahoma law addressing a right of first refusal for lower voltages. On November 15, 2013, SPP made its FERC compliance filing, as required by the July 18, 2013 order. The SPP changes to its tariff and Membership Agreement included provisions that (i) clarify that facilities between 100 kilovolts and 300 kilovolts would be subject to the competitive selection process, (ii) only allow certain evidence, such as state laws (like House Bill 1932) and the holders of existing rights of way, to be considered during the competitive selection process and not earlier in the process; (iii) apply a right of first refusal to transmission projects needed for reliability within three years in certain situations; and (iv) revise the tariff’s competitive selection process, including changes to the criteria for identifying qualifying transmission owners, the requirements for submission of information by transmission owners seeking to participate in competitive selections, and the procedures that govern the competitive selection process.

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.

Fuel Adjustment Clause Review for Calendar Year 2012

On July 31, 2013, the OCC Staff filed an application to review OG&E's fuel adjustment clause for calendar year 2012, including the prudence of OG&E's electric generation, purchased power and fuel procurement costs. OG&E filed the necessary information and documents needed to satisfy the OCC's minimum filing requirement rules on October 9, 2013. A hearing on this matter is scheduled for April 24, 2014.

Request for Modification to Previous Orders

On August 2, 2013, OG&E filed an application at the OCC seeking to make minor modifications to three previous OCC orders. The purpose of the application was to address the timing of certain requirements contained in those orders. OG&E's application proposed to address these issues in OG&E's next general rate case thus avoiding the cost associated with a rate case filing now and benefiting customers by deferring the recovery of certain costs identified in the previous orders. On September 3, 2013, the PUD Staff filed a motion to dismiss OG&E's application. PUD Staff requested that the OCC dismiss OG&E's application and issue an order requiring OG&E to file a rate case for the 2012 test year.

On September 11, 2013, the PUD Staff withdrew their motion to dismiss OG&E's application and on September 12, 2013, filed an application requesting a public hearing, review and possible adjustment of the rates and charges of OG&E based on the 2012 test year. To date, no procedural schedule has been established for either the OG&E application or the PUD Staff application.

Energy Efficiency Program Filing

On October 9, 2013 OG&E filed an application with the APSC requesting approval of interim modifications to approved Energy Efficiency Programs, new tariff revisions and the waiver of certain provisions of the Commission’s Rules for Conservation and Energy Efficiency Programs.

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 rates sales outside of the SPP's energy imbalance service market. On May 2, 2013, the FERC issued an order accepting OG&E's June 2012 triennial market power update.

On December 30, 2013, OG&E submitted to the FERC a market-based rate change in status filing and a revised market-based rate tariff. The revised tariff will authorize OG&E to (i) sell electric energy and capacity at market-based rates without geographic restriction, and (ii) sell ancillary services in the SPP and Midcontinent Independent System Operator, Inc. markets. The primary goal of this filing was to implement the market-based rate authority OG&E needs to fully participate in SPP’s Integrated Marketplace. OG&E requested that FERC issue an order on or before February 28, 2014 that accepts the revised market-based rate tariff to be effective on the date SPP’s Integrated Marketplace goes into operation, which is expected to be March 1, 2014.

Section 206 Complaint

On November 26, 2013, Arkansas Electric Cooperative Corporation filed a complaint at the FERC against OG&E, arguing that the wholesale formula rate contract between OG&E and Arkansas Electric Cooperative Corporation (formerly between OG&E and Arkansas Valley Electric Cooperative) is unjust and unreasonable with respect to several items. After engaging in settlement discussions, OG&E and Arkansas Electric Cooperative Corporation have tentatively agreed to terms of a settlement and are jointly preparing an offer of settlement to be filed with FERC. OG&E believes the reduction in revenue will be less than $1.0 million per year.

17. Quarterly Financial Data (Unaudited)

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

Quarter ended (*In millions, except per share data)*		March 31	June 30	September 30	December 31	Total
Operating revenues	**2013**	**$ 901.4**	**$ 734.2**	**$ 723.2**	**$ 508.9**	**$ 2,867.7**
	2012	$ 840.7	$ 855.0	$ 1,113.4	$ 862.1	$ 3,671.2
Operating income	**2013**	**$ 75.4**	**$ 143.9**	**$ 260.9**	**$ 73.3**	**$ 553.5**
	2012	$ 98.3	$ 177.3	$ 304.0	$ 97.3	$ 676.9
Net income	**2013**	**$ 28.0**	**$ 93.0**	**$ 215.2**	**$ 57.6**	**$ 393.8**
	2012	$ 47.5	$ 101.6	$ 192.4	$ 43.5	$ 385.0
Net income attributable to OGE Energy	**2013**	**$ 23.1**	**$ 91.7**	**$ 215.2**	**$ 57.6**	**$ 387.6**
	2012	$ 37.1	$ 93.9	$ 185.5	$ 38.5	$ 355.0
Basic earnings per average common share attributable to OGE Energy common shareholders (A)	**2013**	**$ 0.12**	**$ 0.46**	**$ 1.08**	**$ 0.29**	**$ 1.96**
	2012	$ 0.19	$ 0.48	$ 0.94	$ 0.19	$ 1.80
Diluted earnings per average common share attributable to OGE Energy common shareholders (A)	**2013**	**$ 0.12**	**$ 0.46**	**$ 1.08**	**$ 0.29**	**$ 1.94**
	2012	$ 0.19	$ 0.47	$ 0.94	$ 0.19	$ 1.79

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

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
OGE Energy Corp.

We have audited the accompanying consolidated balance sheets and statements of capitalization of OGE Energy Corp. as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, cash flows and changes in stockholders' equity for each of the three years in the period ended December 31, 2013. Our audits also included the financial statement schedule listed in the Index at Item 15(a). These financial statements and schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and schedule based on our audits. We did not audit the consolidated financial statements of Enable Midstream Partners, LP (Enable), a partnership in which the Company has a 28.5 percent interest. The Company’s investment in Enable constituted 14.2 percent of the Company’s assets as of December 31, 2013 (none at December 31, 2012), and the Company’s equity earnings in the net income of Enable constituted 19.4 percent of the Company’s income before income taxes for the year ended December 31, 2013 (none for the years ended December 31, 2012 and 2011). Those statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Enable, is based solely on the report of the other auditors.

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

In our opinion, based on our audits and the report of other auditors, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of OGE Energy Corp. at December 31, 2013 and 2012, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles. Also, in our opinion, the related financial statement schedule, when considered in relation to the basic financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), OGE Energy Corp.'s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) and our report dated February 25, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 25, 2014

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

None.

Item 9A. Controls and Procedures.

The Company maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer and chief financial officer, allowing timely decisions regarding required disclosure. The Company has an investment in an unconsolidated affiliate (see Note 3 of Notes to Condensed Consolidated Financial Statements). As the Company does not control this affiliate, its disclosure controls and procedures with respect to such affiliate is more limited than those the Company maintains with respect to its consolidated subsidiaries. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of the Company's management, including the chief executive officer and chief financial officer, of the effectiveness of the Company's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15(d)-15(e) under the Securities Exchange Act of 1934), the chief executive officer and chief financial officer have concluded that the Company's disclosure controls and procedures are effective.

No change in the Company's internal control over financial reporting has occurred during the Company's most recently completed fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Company's internal control over financial reporting (as such term is defined in Rules 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934).

Management's Report on Internal Control Over Financial Reporting

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control system was designed to provide reasonable assurance to the Company's management and Board of Directors regarding the preparation and fair presentation of published financial statements. All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2013. In making this assessment, it used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission in Internal Control-Integrated Framework (1992). Based on our assessment, we believe that, as of December 31, 2013, the Company's internal control over financial reporting is effective based on those criteria.

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

/s/ Peter B. Delaney	/s/ Scott Forbes
Peter B. Delaney, Chairman of the Board, President and Chief Executive Officer	Scott Forbes, Controller and Chief Accounting Officer
/s/ Sean Trauschke	
Sean Trauschke, Vice President and Chief Financial Officer	

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders
OGE Energy Corp.

We have audited OGE Energy Corp.'s internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (1992 framework) (the COSO criteria). OGE Energy Corp.'s management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, OGE Energy Corp. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets and statements of capitalization of OGE Energy Corp. as of December 31, 2013 and 2012, and the related consolidated statements of income, comprehensive income, cash flows and changes in stockholders' equity for each of the three years in the period ended December 31, 2013 of OGE Energy Corp. and our report dated February 25, 2014 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 25, 2014

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Code of Ethics Policy

OGE Energy maintains a code of ethics for our chief executive officer and senior financial officers, including the chief financial officer and chief accounting officer, which is available for public viewing on OGE Energy's web site address www.oge.com under the heading "Investor Relations", "Corporate Governance." The code of ethics will be provided, free of charge, upon request. OGE Energy intends to satisfy the disclosure requirements under Section 5, Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of the code of ethics by posting such information on its web site at the location specified above. OGE Energy will also include in its proxy statement information regarding the Audit Committee financial experts.

Item 11. Executive Compensation.

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

Item 13. Certain Relationships and Related Transactions, and Director Independence.

Item 14. Principal Accounting Fees and Services.

Items 10 through 14 (other than Item 10 information regarding the Code of Ethics) are omitted pursuant to General Instruction G of Form 10-K, because the Company will file copies of a definitive proxy statement with the Securities and Exchange Commission on or about March 28, 2014. Such proxy statement is incorporated herein by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules.

(a) 1. Financial Statements

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

- Consolidated Statements of Income for the years ended December 31, 2013, 2012 and 2011
- Consolidated Statements of Comprehensive Income for the years ended December 31, 2013, 2012 and 2011
- Consolidated Statements of Cash Flows for the years ended December 31, 2013, 2012 and 2011
- Consolidated Balance Sheets at December 31, 2013 and 2012
- Consolidated Statements of Capitalization at December 31, 2013 and 2012
- Consolidated Statements of Changes in Stockholders' Equity for the years ended December 31, 2013, 2012 and 2011
- Notes to Consolidated Financial Statements
- Report of Independent Registered Public Accounting Firm (Audit of Financial Statements)
- Management's Report on Internal Control Over Financial Reporting
- Report of Independent Registered Public Accounting Firm (Audit of Internal Control)

(ii) The financial statements of Enable Midstream Partners, LP, required pursuant to Rule 3-09 of Regulation S-X are filed as Exhibit 99.06

2. Financial Statement Schedule (included in Part IV)

- Schedule II - Valuation and Qualifying Accounts

All other schedules have been omitted since the required information is not applicable or is not material, or because the information required is included in the respective Consolidated Financial Statements or Notes thereto.

3. Exhibits

Exhibit No.	Description
2.01	Asset Purchase Agreement, dated as of August 18, 2003 by and between OG&E and NRG McClain LLC. (Certain exhibits and schedules were omitted and registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed August 20, 2003 (File No. 1-12579) and incorporated by reference herein)
2.02	Amendment No. 1 to Asset Purchase Agreement, dated as of October 22, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.03 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.03	Amendment No. 2 to Asset Purchase Agreement, dated as of October 27, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.04 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.04	Amendment No. 3 to Asset Purchase Agreement, dated as of November 25, 2003 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.05 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.05	Amendment No. 4 to Asset Purchase Agreement, dated as of January 28, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.06 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.06	Amendment No. 5 to Asset Purchase Agreement, dated as of February 13, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.07 to OGE Energy's Form 10-K for the year ended December 31, 2003 (File No. 1-12579) and incorporated by reference herein)
2.07	Amendment No. 6 to Asset Purchase Agreement, dated as of March 12, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.01 to OGE Energy's Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein)
2.08	Amendment No. 7 to Asset Purchase Agreement, dated as of April 15, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.02 to OGE Energy's Form 10-Q for the quarter ended March 31, 2004 (File No. 1-12579) and incorporated by reference herein)
2.09	Amendment No. 8 to Asset Purchase Agreement, dated as of May 15, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
2.1	Amendment No. 9 to Asset Purchase Agreement, dated as of June 2, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.02 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
2.11	Amendment No. 10 to Asset Purchase Agreement, dated as of June 17, 2004 by and between OG&E and NRG McClain LLC. (Filed as Exhibit 2.03 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
2.12	Purchase and Sale Agreement, dated as of January 21, 2008, entered into by and among Redbud Energy I, LLC, Redbud Energy II, LLC and Redbud Energy III, LLC and OG&E. (Certain exhibits and schedules hereto have been omitted and the registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed January 25, 2008 (File No. 1-12579) and incorporated by reference herein)
2.13	Asset Purchase Agreement, dated as of January 21, 2008, entered into by and among OG&E, the Oklahoma Municipal Power Authority and the Grand River Dam Authority. (Certain exhibits and schedules hereto have been omitted and the registrant agrees to furnish supplementally a copy of such omitted exhibits and schedules to the Commission upon request) (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed January 25, 2008 (File No. 1-12579) and incorporated by reference herein)
2.14	Master Formation Agreement dated as of March 14, 2013 by and among CenterPoint Energy, Inc., OGE Energy Corp., Bronco Midstream Holdings, LLC and Bronco Midstream Holdings II, LLC. (Filed as Exhibit 2.01 to OGE Energy's Form 8-K filed March 15, 2013 (File No. 1-12579) and incorporated by reference herein).
3.01	Copy of Restated OGE Energy Corp. Certificate of Incorporation. (Filed as Exhibit 3.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2011 (File No. 1-12579) and incorporated by reference herein)
3.02	Copy of Amended OGE Energy Corp. By-laws. (Filed as Exhibit 3.02 to OGE Energy's Form 10-Q for the quarter ended June 30, 2010 (File No. 1-12579) and incorporated by reference herein)
4.01	Trust Indenture dated October 1, 1995, from OG&E to Boatmen's First National Bank of Oklahoma, Trustee. (Filed as Exhibit 4.29 to Registration Statement No. 33-61821 and incorporated by reference herein)
4.02	Supplemental Indenture No. 2, dated as of July 1, 1997, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed July 17, 1997 (File No. 1-1097) and incorporated by reference herein)

4.03	Supplemental Indenture No. 3, dated as of April 1, 1998, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed April 16, 1998 (File No. 1-1097) and incorporated by reference herein)
4.04	Supplemental Indenture No. 5 dated as of October 24, 2001, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.06 to Registration Statement No. 333-104615 and incorporated by reference herein)
4.05	Supplemental Indenture No. 6 dated as of August 1, 2004, being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.02 to OG&E's Form 8-K filed August 6, 2004 (File No 1-1097) and incorporated by reference herein)
4.06	Indenture dated as of November 1, 2004 between OGE Energy Corp. and UMB Bank, N.A., as trustee. (Filed as Exhibit 4.01 to OGE Energy's Form 8-K filed November 12, 2004 (File No. 1-12579) and incorporated by reference herein)
4.07	Supplemental Indenture No. 1 dated as of November 9, 2004 between OGE Energy Corp. and UMB Bank, N.A., as trustee. (Filed as Exhibit 4.02 to OGE Energy's Form 8-K filed November 12, 2004 (File No. 1-12579) and incorporated by reference herein)
4.08	Supplemental Indenture No. 7 dated as of January 1, 2006 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.08 to OG&E's Form 8-K filed January 6, 2006 (File No. 1-1097) and incorporated by reference herein)
4.09	Supplemental Indenture No. 8 dated as of January 15, 2008 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed January 31, 2008 (File No. 1-1097) and incorporated by reference herein)
4.10	Supplemental Indenture No. 9 dated as of September 1, 2008 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed September 9, 2008 (File No. 1-1097) and incorporated by reference herein)
4.11	Supplemental Indenture No. 10 dated as of December 1, 2008 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed December 11, 2008 (File No. 1-1097) and incorporated by reference herein)
4.12	Supplemental Indenture No. 11 dated as of June 1, 2010 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed June 8, 2010 (File No. 1-1097) and incorporated by reference herein)
4.13	Supplemental Indenture No. 12 dated as of May 15, 2011 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed May 27, 2011 (File No. 1-1097) and incorporated by reference herein)
4.14	Supplemental Indenture No. 13 dated as of May 1, 2013 between OG&E and UMB Bank, N.A., as trustee, creating the Senior Notes. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed May 13, 2013 (File No. 1-1097) and incorporated by reference herein)
10.01*	OGE Energy's 1998 Stock Incentive Plan. (Filed as Exhibit 10.07 to OGE Energy's Form 10-K for the year ended December 31, 1998 (File No. 1-12579) and incorporated by reference herein)
10.02*	OGE Energy's 2003 Stock Incentive Plan. (Filed as Annex A to OGE Energy's Proxy Statement for the 2003 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)
10.03	Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's rate case. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed July 9, 2012 (File No. 1-12579) and incorporated by reference herein)
10.04	Amended and Restated Facility Operating Agreement for the McClain Generating Facility dated as of July 9, 2004 between OG&E and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.03 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
10.05	Amended and Restated Ownership and Operation Agreement for the McClain Generating Facility dated as of July 9, 2004 between OG&E and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.04 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
10.06	Operating and Maintenance Agreement for the Transmission Assets of the McClain Generating Facility dated as of August 25, 2003 between OG&E and the Oklahoma Municipal Power Authority. (Filed as Exhibit 10.05 to OGE Energy's Form 10-Q for the quarter ended June 30, 2004 (File No. 1-12579) and incorporated by reference herein)
10.07*	Amendment No. 1 to OGE Energy's 2003 Stock Incentive Plan. (Filed as Exhibit 10.23 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)
10.08	Intrastate Firm No-Notice, Load Following Transportation and Storage Services Agreement dated as of May 1, 2003 between OG&E and Enogex. [Confidential treatment has been requested for certain portions of this exhibit.] (Filed as Exhibit 10.24 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)
10.09*	Form of Split Dollar Agreement. (Filed as Exhibit 10.32 to OGE Energy's Form 10-K for the year ended December 31, 2004 (File No. 1-12579) and incorporated by reference herein)

10.10	Credit agreement dated as of December 13, 2011, by and between OGE Energy, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Corporate Bank, Ltd., The Royal Bank of Scotland PLC, UBS Securities LLC and Union Bank, N.A., as Co-Documentation Agents. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed December 19, 2011 (File No. 1-12579) and incorporated by reference herein)
10.11	Credit agreement dated as of December 13, 2011, by and between OG&E, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Corporate Bank, Ltd., The Royal Bank of Scotland PLC, UBS Securities LLC and Union Bank, N.A., as Co-Documentation Agents. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed December 19, 2011 (File No. 1-12579) and incorporated by reference herein)
10.12*	Amendment No. 1 to OGE Energy's 1998 Stock Incentive Plan. (Filed as Exhibit 10.26 to OGE Energy's Form 10-K for the year ended December 31, 2006 (File No. 1-12579) and incorporated by reference herein)
10.13*	Amendment No. 2 to OGE Energy's 2003 Stock Incentive Plan. (Filed as Exhibit 10.27 to OGE Energy's Form 10-K for the year ended December 31, 2006 (File No. 1-12579) and incorporated by reference herein)
10.14	Ownership and Operating Agreement, dated as of January 21, 2008, entered into by and among OG&E, the Oklahoma Municipal Power Authority and the Grand River Dam Authority. (Filed as Exhibit 10.01 to OGE Energy's Form 8-K filed January 25, 2008 (File No. 1-12579) and incorporated by reference herein)
10.15*	OGE Energy Supplemental Executive Retirement Plan, as amended and restated. (Filed as Exhibit 10.03 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.16*	OGE Energy Restoration of Retirement Income Plan, as amended and restated. (Filed as Exhibit 10.04 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.17*	OGE Energy Deferred Compensation Plan, as amended and restated. (Filed as Exhibit 10.05 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.18*	Amendment No. 3 to OGE Energy's 2003 Stock Incentive Plan. (Filed as Exhibit 10.06 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.19*	Amendment No. 2 to OGE Energy's 1998 Stock Incentive Plan. (Filed as Exhibit 10.07 to OGE Energy's Form 10-Q for the quarter ended March 31, 2008 (File No. 1-12579) and incorporated by reference herein)
10.20*	OGE Energy's 2008 Stock Incentive Plan. (Filed as Annex A to OGE Energy's Proxy Statement for the 2008 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)
10.21*	OGE Energy's 2008 Annual Incentive Compensation Plan. (Filed as Annex B to OGE Energy's Proxy Statement for the 2008 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)
10.22*	Form of Employment Agreement for all existing and future officers of the Company relating to change of control. (Filed as Exhibit 10.28 to OGE Energy's Form 10-K for the year ended December 31, 2011 (File No. 1-12579) and incorporated by reference herein)
10.23*	Form of Restricted Stock Agreement under OGE Energy's 2008 Stock Incentive Plan. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended September 30, 2008 (File No. 1-12579) and incorporated by reference herein)
10.24	Agreement, dated February 17, 2010, between OG&E and Oklahoma Department of Environmental Quality. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed February 23, 2010 (File No. 1-12579) and incorporated by reference herein)
10.25*	Amendment No. 1 to OGE Energy's Restoration of Retirement Income Plan. (Filed as Exhibit 10.40 to OGE Energy's Form 10-K for the year ended December 31, 2009 (File No. 1-12579) and incorporated by reference herein)
10.26*	Amendment No. 1 to OGE Energy's Deferred Compensation Plan. (Filed as Exhibit 10.33 to OGE Energy's Form 10-K for the year ended December 31, 2011 (File No. 1-12579) and incorporated by reference herein)
10.27	Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Smart Grid application. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed June 1, 2010 (File No. 1-12579) and incorporated by reference herein)
10.28	Copy of Settlement Agreement with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Crossroads wind farm application. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed July 1, 2010 (File No. 1-12579) and incorporated by reference herein)
10.29	Copy of Settlement Agreement with Arkansas Public Service Commission Staff, the Arkansas Attorney General and others relating to OG&E's rate case. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed May 19, 2011 (File No. 1-12579) and incorporated by reference herein)
10.30	Copy of Settlement Agreement with Arkansas Public Service Commission Staff, the Arkansas Attorney General and others relating to OG&E's Smart Grid application. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed June 28, 2011 (File No. 1-12579) and incorporated by reference herein)
10.31*	Amendment No. 2 to OGE Energy's Deferred Compensation Plan. (Filed as Exhibit 10.41 to OGE Energy's Form 10-K for the year ended December 31, 2009 (File No. 1-12579) and incorporated by reference herein)

10.32*	Amendment No. 3 to OGE Energy's Deferred Compensation Plan. (Filed as Exhibit 10.39 to OGE Energy's Form 10-K for the year ended December 31, 2011 (File No. 1-12579) and incorporated by reference herein)
10.33*	Amendment No. 1 to OGE Energy's 2008 Stock Incentive Plan. (Filed as Exhibit 10.40 to OGE Energy's Form 10-K for the year ended December 31, 2011 (File No. 1-12579) and incorporated by reference herein)
10.34*	Director Compensation.
10.35*	Executive Officer Compensation.
10.36	First Amended and Restated Agreement of Limited Partnership of CenterPoint Energy Field Services LP dated as of May 1, 2013 (Filed as Exhibit 10.01 to OGE Energy's Form 8-K filed May 7, 2013 (File No. 1-12579) and incorporated by reference herein)
10.37	Amended and Restated Limited Liability Company Agreement of CNP OGE GP LLC dated as of May 1, 2013 (Filed as Exhibit 10.02 to OGE Energy's Form 8-K filed May 7, 2013 (File No. 1-12579) and incorporated by reference herein)
10.38	Registration Rights Agreement dated as of May 1, 2013 by and among CenterPoint Energy Field Services LP, CenterPoint Energy Resources Corp., OGE Enogex Holdings LLC, and Enogex Holdings LLC (Filed as Exhibit 10.03 to OGE Energy's Form 8-K filed May 7, 2013 (File No. 1-12579) and incorporated by reference herein)
10.39	Omnibus Agreement dated as of May 1, 2013 among CenterPoint Energy, Inc., OGE Energy Corp., Enogex Holdings LLC and CenterPoint Energy Field Services LP (Filed as Exhibit 10.04 to OGE Energy's Form 8-K filed May 7, 2013 (File No. 1-12579) and incorporated by reference herein)
10.40*	OGE Energy's 2013 Stock Incentive Plan. (Filed as Annex B to OGE Energy's Proxy Statement for the 2013 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)
10.41*	OGE Energy's 2013 Annual Incentive Compensation Plan. (Filed as Annex C to OGE Energy's Proxy Statement for the 2013 Annual Meeting of Shareowners (File No. 1-12579) and incorporated by reference herein)
10.42	Letter of extension dated as of July 29, 2013 for the Company's credit agreement dated as of December 13, 2011, by and between OGE Energy, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Corporate Bank, Ltd., The Royal Bank of Scotland PLC, UBS Securities LLC and Union Bank, N.A., as Co-Documentation Agents (Filed as Exhibit 10.01 to OGE Energy's Form 8-K filed August 2, 2013 (File No. 1-12579) and incorporated by reference herein)
10.43	Letter of extension dated as of July 29, 2013 for OG&E's credit agreement dated as of December 13,2011, by and between OG&E, the Lenders thereto, Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Corporate Bank, Ltd., The Royal Bank of Scotland PLC, UBS Securities LLC and Union Bank, N.A., as Co-Documentation Agents (Filed as Exhibit 10.02 to OGE Energy's Form 8-K filed August 2, 2013 (File No. 1-12579) and incorporated by reference herein)
10.44*	Amendment No. 4 to the Company's Deferred Compensation Plan (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q filed November 6, 2013 (File No. 1-12579) and incorporated by reference herein)
10.45*	OGE Energy Corp. Involuntary Severance Benefits Plans for Non-Officers (Applicable only to non-officers of Enogex LLC seconded to Enable Midstream Partners, LP or Enable GP, LLC or one of its subsidiaries (Filed as Exhibit 10.02 to OGE Energy's Form 10-Q filed November 6, 2013 (File No. 1-12579) and incorporated by reference herein)
10.46*	OGE Energy Corp. Involuntary Severance Benefits Plans for Officers (Applicable only to officers of Enogex LLC seconded to Enable Midstream Partners, LP or Enable GP, LLC or one of its subsidiaries (Filed as Exhibit 10.03 to OGE Energy's Form 10-Q filed November 6, 2013 (File No. 1-12579) and incorporated by reference herein)
10.47*	Retention Agreement effective as of October 24, 2013, by and between OGE Enogex Holdings, LLC and E. Keith Mitchell (Filed as Exhibit 10.04 to OGE Energy's Form 10-Q filed November 6, 2013 (File No. 1-12579) and incorporated by reference herein)
12.01	Calculation of Ratio of Earnings to Fixed Charges.
21.01	Subsidiaries of the Registrant.
23.01	Consent of Ernst & Young LLP.
23.02	Consent of Deloitte & Touche LLP.
24.01	Power of Attorney.
31.01	Certifications Pursuant to Rule 13a-14(a)/15d-14(a) As Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.01	Certification Pursuant to 18 U.S.C. Section 1350 As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.01	Cautionary Statement for Purposes of the "Safe Harbor" Provisions of the Private Securities Litigation Reform Act of 1995.

99.02	Copy of APSC order with Arkansas Public Service Commission Staff, the Arkansas Attorney General and others relating to OG&E's rate case. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed June 22, 2011 (File No. 1-12579) and incorporated by reference herein)
99.03	Copy of OCC Order with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Smart Grid application. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed July 7, 2010 (File No. 1-12579) and incorporated by reference herein)
99.04	Copy of OCC Order with Oklahoma Corporation Commission Staff, the Oklahoma Attorney General and others relating to OG&E's Crossroads wind farm application. (Filed as Exhibit 99.04 to OGE Energy's Form 10-Q for the quarter ended June 30, 2010 (File No. 1-12579) and incorporated by reference herein)
99.05	Description of Capital Stock. (Filed as Exhibit 99.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2013 (File No. 1-12579) and incorporated by reference herein)
99.06	Financial Statements of Enable Midstream Partners, LP as of and for the three years ended December 31, 2013
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Schema Document.
101.PRE	XBRL Taxonomy Presentation Linkbase Document.
101.LAB	XBRL Taxonomy Label Linkbase Document.
101.CAL	XBRL Taxonomy Calculation Linkbase Document.
101.DEF	XBRL Definition Linkbase Document.

* Represents executive compensation plans and arrangements.

OGE ENERGY CORP.

SCHEDULE II - Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Deductions (A)	Balance at End of Period
	(In millions)			
Balance at December 31, 2011				
Reserve for Uncollectible Accounts	$ 1.9	$ 5.8	$ 3.9	$ 3.8
Balance at December 31, 2012				
Reserve for Uncollectible Accounts	$ 3.8	$ 3.3	$ 4.5	$ 2.6
Balance at December 31, 2013				
Reserve for Uncollectible Accounts	**$ 2.6**	**$ 2.5**	**$ 3.2**	**$ 1.9**

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

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, the Registrant has duly caused this Report to be signed on its behalf by the undersigned, thereunto duly authorized, in the City of Oklahoma City, and State of Oklahoma on the 25th day of February, 2014.

OGE ENERGY CORP.
(Registrant)

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

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended, this Report has been signed below by the following persons on behalf of the Registrant in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Peter B. Delaney Peter B. Delaney	Principal Executive Officer and Director;	February 25, 2014
/s/ Sean Trauschke Sean Trauschke	Principal Financial Officer; and	February 25, 2014
/s/ Scott Forbes Scott Forbes	Principal Accounting Officer.	February 25, 2014
James H. Brandi	Director;	
Wayne H. Brunetti	Director;	
Luke R. Corbett	Director;	
John D. Groendyke	Director;	
Kirk Humphreys	Director;	
Robert Kelley	Director;	
Robert O. Lorenz	Director;	
Judy R. McReynolds	Director;	
Leroy C. Richie	Director. and	
Sheila G. Talton	Director	
/s/ Peter B. Delaney By Peter B. Delaney (attorney-in-fact)		February 25, 2014

Exhibit 10.34

OGE Energy Corp.
Director Compensation

Compensation of non-officer directors of the Company in 2013 included an annual retainer fee of $128,600, of which $45,600 was payable in cash in monthly installments and $83,000 was deposited in the director's account under the Company's Deferred Compensation Plan in December 2013 and converted to 2,441.894 common stock units based on the closing price of the Company's Common Stock on December 5, 2013. All non-officer directors received $2,000 for each Board meeting and $2,000 for each committee meeting attended. The lead director received an additional $17,500 cash retainer in 2013. The chairman of the Audit Committee received an additional $12,500 cash retainer in 2013. The chairmen of the Compensation and Nominating and Corporate Governance Committees received an additional $7,500 annual cash retainer in 2013. Each chairman of a board committee also received a meeting fee of $2,000 for each meeting (either in person or by phone) with management to address committee matters. Each member of the Audit Committee also received an additional annual retainer of $5,000. These amounts represent the total fees paid to directors in their capacities as directors of the Company and OG&E in 2013.

Under the Company's Deferred Compensation Plan, non-officer directors may defer payment of all or part of their attendance fees and the cash portion of their annual retainer fee, which deferred amounts are credited to their account as of the first day of the month in which the deferred amounts otherwise would have been paid. Amounts credited to the accounts are assumed to be invested in one or more of the investment options permitted under the Company's Deferred Compensation Plan. In 2013, those investment options included a Company Common Stock fund, whose value was determined based on the stock price of the Company's Common Stock. When an individual ceases to be a director of the Company, all amounts credited under the Company's Deferred Compensation Plan are paid in cash in a lump sum or installments. In certain circumstances, participants may also be entitled to in-service withdrawals from the Company's Deferred Compensation Plan.

In December 2013, the Compensation Committee met to consider director compensation. At that meeting, the Compensation Committee increased the additional annual retainer for the chairmen of the Compensation and Nominating and Corporate Governance Committees for 2014 to $10,000 from $7,500, increased the additional annual retainer for the chairman of the Audit Committee for 2014 to $15,000 from $12,500 and increased the additional annual retainer for the lead director for 2014 to $20,000 from $17,500.

Exhibit 10.35

OGE Energy Corp.
Executive Officer Compensation

Executive Compensation

In December 2013, the Compensation Committee of the OGE Energy Corp. board of directors took actions setting executives' salaries, target amount of annual bonus awards and target amounts of long-term compensation awards for 2014. Executive compensation was set by the Compensation Committee after consideration of, among other things, individual performance and market-based data on compensation for executives with similar duties. Payouts of 2014 annual bonus targets and long-term awards are dependent on achievement of specified corporate goals that will be established by the Compensation Committee at a subsequent meeting, and no officer is assured of any payout.

Salary

The Compensation Committee established the base salaries for its senior executive group. The salaries for 2014 for the OGE Energy officers who are expected to be named in the Summary Compensation Table in OGE Energy's 2014 Proxy Statement are as follows:

Executive Officer	2014 Base Salary
Peter B. Delaney, Chairman, President and Chief Executive Officer	$980,000
Sean Trauschke, Vice President and Chief Financial Officer	$575,000
E. Keith Mitchell, President and Chief Operating Officer of Enogex Holdings; President of Enogex LLC	$400,000
Stephen E. Merrill, Chief Operating Officer of Enogex LLC	$350,000
Jean C. Leger, Jr., Vice President - Utility Operations of OG&E	$340,100

Establishment of 2014 Annual Incentive Awards

As stated above, at its December 2013 meeting, the Compensation Committee approved the target amount of annual incentive awards, expressed as a percentage of salary, with the officer having the ability, depending upon achievement of the 2014 corporate goals to be set by the Compensation Committee at a subsequent meeting, to receive from 0 percent to 150 percent of such targeted amount. For 2014, the targeted amount ranged from 65 percent to 100 percent of the approved 2014 base salary for the executive officers in the above table.

Establishment of Long-Term Awards

At its December 2013 meeting, the Compensation Committee also approved the level of target long-term incentive awards, expressed as a percentage of salary, with the officer having the ability to receive from 0 percent to 200 percent of such targeted amount at the end of a three-year performance period depending upon achievement of the corporate goals to be set by the Compensation Committee at a subsequent meeting. For 2014, the targeted amount ranged from 115 percent to 245 percent of the approved 2014 base salary for the executive officers in the above table.

Other Benefits

Retirement Benefits. A significant amount of the Company's employees hired before December 1, 2009, including executive officers, are eligible to participate in the Company's Pension Plan and certain employees are eligible to participate in the Company's Restoration of Retirement Income Plan that enables participants, including executive officers, to receive the same benefits that they would have received under the Company's Pension Plan in the absence of limitations imposed by the Federal tax laws. In addition, the supplemental executive retirement plan, which was adopted in 1993, provides a supplemental executive retirement plan in order to attract and retain lateral hires or other executives designated by the Compensation Committee of the Company's Board of Directors who may not otherwise qualify for a sufficient level of benefits under the Company's Pension Plan and Restoration of Retirement Income Plan. Mr. Delaney is the only employee, including executive officers, who participates in the supplemental executive retirement plan. Mr. Delaney's participation in the supplemental executive retirement plan was the result of arms-length bargaining between Mr. Delaney and the Company at the time of his hire in April 2002 as Executive Vice President of the Company.

Almost all employees of the Company, including executive officers, also are eligible to participate in our 401(k) Plan. Participants may contribute each pay period any whole percentage between two percent and 19 percent of their compensation, as defined in the 401(k) Plan, for that pay period. Participants who have attained age 50 before the close of a year are allowed to make additional contributions referred to as "Catch-Up Contributions," subject to certain limitations of the Code. Participants may designate, at their discretion, all or any portion of their contributions as: (i) a before-tax contribution under Section 401(k) of the Code subject to the limitations thereof; or (ii) a contribution made on an after-tax basis. The 401(k) Plan also includes an eligible automatic contribution arrangement and provides for a qualified default investment alternative consistent with the U.S. Department of Labor regulations. Participants may elect, in accordance with the 401(k) Plan procedures, to have his or her future salary deferral rate to be automatically increased annually on a date and in an amount as specified by the participant in such election.

No Company contributions are made with respect to a participant's Catch-Up Contributions, rollover contributions, or with respect to a participant's contributions based on overtime payments, pay-in-lieu of overtime for exempt personnel, special lump-sum recognition awards and lump-sum merit awards included in compensation for determining the amount of participant contributions. Once made, the Company's contribution may be directed to any available investment option in the 401(k) Plan. The Company match contributions vest over a three-year period. After two years of service, participants become 20 percent vested in their Company contribution account and become fully vested on completing three years of service. In addition, participants fully vest when they are eligible for normal or early retirement under the Pension Plan, in the event of their termination due to death or permanent disability or upon attainment of age 65 while employed by the Company or its affiliates.

The Company provides a nonqualified deferred compensation plan which is intended to be an unfunded plan. The plan's primary purpose is to provide a tax-deferred capital accumulation vehicle for a select group of management, highly compensated employees and non-employee members of the Board of Directors of the Company and to supplement such employees' 401(k) Plan contributions as well as offering this plan to be competitive in the marketplace. Eligible employees who enroll in the plan have the following deferral options: (i) eligible employees may elect to defer up to a maximum of 70 percent of base salary and 100 percent of annual bonus awards or (ii) eligible employees may elect a deferral percentage of base salary and bonus awards based on the deferral percentage elected for a year under the 401(k) Plan with such deferrals to start when maximum deferrals to the qualified 401(k) Plan have been made because of limitations in that plan. Eligible directors who enroll in the plan may elect to defer up to a maximum of 100 percent of directors' meeting fees and annual retainers.

The Company matches employee (but not non-employee director) deferrals to make up for any match lost in the 401(k) Plan because of deferrals to the deferred compensation plan, and to allow for a match that would have been made under the 401(k) Plan on that portion of either the first six percent of total compensation or the first five percent of total compensation, depending on the option the participant elected under the choice provided to eligible employees in the qualified 401(k) Plan discussed above, deferred that exceeds the limits allowed in the 401(k) Plan. Matching credits vest based on years of service, with full vesting after three years or, if earlier, on retirement, disability, death, a change in control of the Company or termination of the plan.

Deferrals, plus any Company match, are credited to a recordkeeping account in the participant's name. Earnings on the deferrals are indexed to the assumed investment funds selected by the participant. In 2013, those investment options included a Company Common Stock fund, whose value was determined based on the stock price of the Company's Common Stock.

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

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

Perquisites. The Company also offers executive officers a limited amount of perquisites. These include payment of social membership dues at dining and country clubs for certain executive officers, an annual physical exam for all executive officers, a relocation program and, in the case of Mr. Delaney, use of a Company car. In reviewing the perquisites and the benefits under the supplemental executive retirement plan, 401(k) Plan, Deferred Compensation Plan, Pension Plan and Restoration of Retirement Income Plan, the Compensation Committee sought in 2013 to provide participants with benefits at least commensurate with those offered by other utilities of comparable size.

Change-of-Control Provisions and Employment Agreements. None of the Company's executive officers has an employment agreement with the Company. Each of the executive officers has a change of control agreement that becomes effective upon a change of control. If an executive officer's employment is terminated by the Company "without cause" following a change of control, the executive officer is entitled to the following payments: (i) all accrued and unpaid compensation and a prorated annual bonus and (ii) a severance payment equal to 2.99 times the sum of such officer's (a) annual base salary and (b) highest recent annual bonus. The change of control agreements are considered to be double trigger agreements because payment will only be made following a change of control and termination of employment. The 2.99 times multiple for change-of-control payments was selected because at the time it was considered standard. Although many companies also include provisions for tax gross-up payments to cover any excise taxes on excess parachute payments, the Company's Board of Directors decided not to include this additional benefit in the Company's agreements. Instead, under the Company's agreements if the excise tax would be imposed, the change-of-control payments will be reduced to a point where no excise tax would be payable, if such reduction would result in a greater after-tax payment.

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

Exhibit 12.01

OGE Energy Corp.
Ratio of Earnings to Fixed Charges

Year ended December 31 *(In millions)*	**2013**	2012	2011	2010	2009
Earnings:					
Pre-tax income	**$ 524.1**	$ 520.1	$ 524.3	$ 461.4	$ 382.2
Add: Fixed charges	**157.2**	174.4	161.8	150.1	154.5
Subtotal	**681.3**	694.5	686.1	611.5	536.7
Subtract:					
Allowance for borrowed funds used during construction	**3.4**	3.5	10.4	5.5	8.3
Other capitalized interest	**2.0**	4.5	8.7	2.5	6.3
Total earnings	**675.9**	686.5	667.0	603.5	522.1
Fixed Charges:					
Interest on long-term debt	**147.6**	163.4	154.8	141.8	143.6
Interest on short-term debt and other interest charges	**5.3**	8.7	5.2	5.9	8.4
Calculated interest on leased property	**4.3**	2.3	1.8	2.4	2.5
Total fixed charges	**$ 157.2**	$ 174.4	$ 161.8	$ 150.1	$ 154.5
Ratio of Earnings to Fixed Charges	**4.30**	3.94	4.12	4.02	3.38

Exhibit 21.01

OGE Energy Corp.
Subsidiaries of the Registrant

Name of Subsidiary	Jurisdiction of Incorporation	Percentage of Ownership
Oklahoma Gas and Electric Company	Oklahoma	100.0
OGE Enogex Holdings LLC	Delaware	100.0

The above listed subsidiaries have been consolidated in the Registrant's financial statements. Certain of the Company's subsidiaries have been omitted from the list above in accordance with Rule 1-02(w) of Regulation S-X.

Exhibit 23.01

Consent of Independent Registered Public Accounting Firm

We consent to the incorporation by reference in the Registration Statement (Form S-8 No. 333-71327) pertaining to the 1998 stock incentive plan, the Registration Statement (Form S-8 No. 333-92423) pertaining to the deferred compensation plan, the Registration Statement (Form S-8 No. 333-104497) pertaining to the employees' stock ownership and retirement savings plan, the Registration Statement (Form S-8 No. 333-115735) pertaining to the 2003 stock incentive plan, the Registration Statement, including Post-Effective No. 1, (Form S-8 No. 333-152022) pertaining to the 2008 stock incentive plan, Registration Statement (Form S-8 No. 333-190406) pertaining to the employees stock ownership and retirement savings plan, Registration Statement (Form S-8 No. 333-190405) pertaining to the 2013 stock incentive plan, the Registration Statement, including Post-Effective No. 1, (Form S-3ASR No. 333-178093) pertaining to the dividend reinvestment and stock purchase plan and the Registration Statement (Form S-3ASR No. 333-188309) pertaining to common stock and debt securities, of our reports dated February 25, 2014, with respect to the consolidated financial statements and schedule of OGE Energy Corp., and the effectiveness of internal control over financial reporting of OGE Energy Corp., included in this Annual Report (Form 10-K) for the year ended December 31, 2013.

/s/ Ernst & Young LLP
Ernst & Young LLP

Oklahoma City, Oklahoma
February 25, 2014

Exhibit 23.02

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement on Form S-8 (No. 333-71327), Registration Statement on Form S-8 (No. 333-92423), Registration Statement on Form S-8 (No. 333-104497), Registration Statement on Form S-8 (No. 333-115735), Registration Statement, including Post-Effective No. 1, on Form S-8 (No. 333-152022), Registration Statement on Form S-8 (No. 333-190406), Registration Statement on Form S-8 (No. 333-190405), Registration Statement, including Post-Effective No. 1, on Form S-3ASR (No. 333-178093) and Registration Statement on Form S-3ASR (No. 333-188309), of our report dated February 21, 2014 relating to the combined and consolidated financial statements of Enable Midstream Partners, LP (previously named CenterPoint Energy Field Services, LLC) and subsidiaries, (collectively the "Partnership") (which report expresses an unqualified opinion and includes an explanatory paragraph relating to the preparation of the combined and consolidated financial statements of Enable Midstream Partners, LP from the historical accounting records maintained by CenterPoint Energy, Inc. and its subsidiaries) included in this annual report on Form 10-K of OGE Energy Corp. for the year ended December 31, 2013.

/s/ Deloitte & Touche LLP

Houston, Texas
February 25, 2014

Exhibit 24.01

Power of Attorney

WHEREAS, OGE ENERGY CORP., an Oklahoma corporation (herein referred to as the "Company"), is about to file with the Securities and Exchange Commission, under the provisions of the Securities Exchange Act of 1934, as amended, its annual report on Form 10-K for the year ended December 31, 2013; and

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

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

IN WITNESS WHEREOF, the undersigned have hereunto set their hands this 24th day of February, 2014.

Peter B. Delaney, Chairman, Principal Executive Officer and Director	/s/ Peter B. Delaney
James H. Brandi, Director	/s/ James H. Brandi
Wayne H. Brunetti, Director	/s/ Wayne H. Brunetti
Luke R. Corbett, Director	/s/ Luke R. Corbett
John D. Groendyke, Director	/s/ John D. Groendyke
Kirk Humphreys, Director	/s/ Kirk Humphreys
Robert Kelley, Director	/s/ Robert Kelley
Robert O. Lorenz, Director	/s/ Robert O. Lorenz
Judy R. McReynolds, Director	/s/ Judy R. McReynolds
Leroy C. Richie, Director	/s/ Leroy C. Richie
Sheila G. Talton	/s/ Sheila G. Talton
Sean Trauschke, Principal Financial Officer	/s/ Sean Trauschke
Scott Forbes, Principal Accounting Officer	/s/ Scott Forbes

STATE OF OKLAHOMA)
) SS
COUNTY OF OKLAHOMA)

On the date indicated above, before me, Kelly Hamilton-Coyer, Notary Public in and for said County and State, the above named directors and officers of OGE ENERGY CORP., an Oklahoma corporation, known to me to be the persons whose names are subscribed to the foregoing instrument, severally acknowledged to me that they executed the same as their own free act and deed.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my official seal on the 24th day of February, 2014.

/s/ Kelly Hamilton-Coyer
By: Kelly Hamilton-Coyer
Notary Public

My commission expires:
July 6, 2017

Exhibit 31.01

CERTIFICATIONS

I, Peter B. Delaney, certify that:

1. I have reviewed this annual report on Form 10-K of OGE Energy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2014

/s/ Peter B. Delaney

Peter B. Delaney

Chairman of the Board, President and Chief Executive Officer

Exhibit 31.01

CERTIFICATIONS

I, Sean Trauschke, certify that:

1. I have reviewed this annual report on Form 10-K of OGE Energy Corp.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

b) designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) all significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 25, 2014

/s/ Sean Trauschke

Sean Trauschke
Chief Financial Officer

Exhibit 32.01

Certification Pursuant to 18 U.S.C. Section 1350
As Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of the Company on Form 10-K for the period ended December 31, 2013, as filed with the Securities and Exchange Commission (the "Report"), each of the undersigned does hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

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

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

February 25, 2014

/s/ Peter B. Delaney

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

/s/ Sean Trauschke

Sean Trauschke
Chief Financial Officer

Exhibit 99.01

OGE Energy Corp. Cautionary Factors

The Private Securities Litigation Reform Act of 1995 provides a "safe harbor" for forward-looking statements to encourage such disclosures without the threat of litigation providing those statements are identified as forward-looking and are accompanied by meaningful, cautionary statements identifying important factors that could cause the actual results to differ materially from those projected in the statement. Forward-looking statements have been and will be made in written documents and oral presentations of the Company. Such statements are based on management's beliefs as well as assumptions made by and information currently available to management. When used in the Company's documents or oral presentations, the words "anticipate", "believe", "estimate", "expect", "intend", "objective", "plan", "possible", "potential", "project" and similar expressions are intended to identify forward-looking statements. In addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements, factors that could cause the Company's actual results to differ materially from the forward-looking statements include, but are not limited to, the following, by segment:

Consolidated (including Electric Utility, Natural Gas Midstream Operations)

- Changing market conditions and a variety of other factors associated with physical energy and financial trading activities including, but not limited to, price, basis, credit, liquidity, volatility, capacity, transmission, currency, interest rate and warranty risks;
- Risks associated with PRM strategies intended to mitigate exposure to adverse movement in the prices of natural gas on both a global and regional basis, including commodity price changes, market supply shortages, interest rate changes and counterparty default;
- General economic conditions, including the availability of credit, access to existing lines of credit, access to the commercial paper markets, actions of rating agencies and their impact on capital expenditures and our ability to access the capital markets, inflation rates and monetary fluctuations;
- Customer business conditions including demand for their products or services and supply of labor and materials used in creating their products and services currently and in the future;
- Financial or regulatory accounting principles or policies imposed by the Financial Accounting Standards Board, the Securities and Exchange Commission, the FERC, state public utility commissions; the regional state committee which regulates the SPP; state entities which regulate natural gas transmission, gathering and processing and similar entities with regulatory oversight;
- Environmental laws, safety laws or other regulations passed by the EPA, the Oklahoma Department of Environmental Quality or other governing agencies that may impact the cost of operations or restrict or change the way the Company operates its facilities;
- Availability or cost of capital, including changes in interest rates, market perceptions of the utility and energy-related industries, the Company or any of its subsidiaries or security ratings;
- Employee workforce factors including changes in key executives and employee retention;
- Social attitudes regarding the utility, natural gas and power industries;
- Identification of suitable investment opportunities to enhance shareowner returns and achieve long-term financial objectives through business acquisitions and divestitures;
- Some future investments made by the Company could take the form of noncontrolling interests which would limit the Company's ability to control the development or operation of an investment;
- Increased pension and healthcare costs;
- Costs and other effects of legal and administrative proceedings, settlements, investigations, claims and matters, including but not limited to those described in Note 15 of Notes to Consolidated Financial Statements in this Form 10-K;
- Technological developments, changing markets and other factors that result in competitive disadvantages and create the potential for impairment of existing assets;
- The cost of protecting assets against, or damage due to, terrorism or cyber attacks and other catastrophic events; and
- Other business or investment considerations that may be disclosed from time to time in the Company's Securities and Exchange Commission filings or in other publicly disseminated written documents.

Electric Utility Segment

- Increased competition in the utility industry, including effects of decreasing margins as a result of competitive pressures; industry restructuring initiatives; transmission system operation and/or administration initiatives;

recovery of investments made under traditional regulation; nature of competitors entering the industry; retail wheeling; a new pricing structure; and former customers entering the generation market;

- Factors affecting utility operations such as unusual weather conditions; catastrophic weather-related damage; unscheduled generation outages, unusual maintenance or repairs; unanticipated changes to fossil fuel, natural gas or coal supply costs or availability due to higher demand, shortages, transportation problems or other developments; environmental incidents; or electric transmission or gas pipeline system constraints;
- Rate-setting policies or procedures of regulatory entities, including environmental externalities;
- Approval of future regulatory filings with the OCC or the APSC; and
- Discontinuance of accounting principles for certain types of rate-regulated activities.

Natural Gas Midstream Operations

- Increased competition in the natural gas processing industry, including effects of decreasing margins as a result of competitive pressures, commodity exposure and nature of competitors entering the industry; and
- Cold weather extremes that may impact the ability of producing customers to maintain gas deliveries, or the quality of such deliveries, into the pipeline system.
- difficulty in making accurate assumptions and projections regarding future revenues and costs associated with the Company's equity investment in Enable that the Company does not control;
- the risk that Enable may not be able to successfully integrate the operations of Enogex LLC and the businesses contributed by CenterPoint as discussed in Note 3

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.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Members of
Enable Midstream Partners, LP
Oklahoma City, Oklahoma

We have audited the accompanying combined and consolidated balance sheets of Enable Midstream Partners, LP (previously named CenterPoint Energy Field Services, LLC) and subsidiaries (the "Partnership") as of December 31, 2013 and 2012, and the related combined and consolidated statements of income, comprehensive income, cash flows, and parent net equity and partners’ capital for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Partnership is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Partnership's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such combined and consolidated financial statements present fairly, in all material respects, the financial position of Enable Midstream Partners, LP and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the combined and consolidated financial statements, the combined and consolidated financial statements have been prepared from the historical accounting records maintained by CenterPoint Energy, Inc. and its subsidiaries for the Partnership until May 1, 2013 and may not necessarily be indicative of the financial position, results of operations and cash flows that would have existed had the Partnership operated as a separate and unaffiliated company until the Partnership formation on May 1, 2013. All of the Partnership’s combined entities were under common control and management for the periods presented until May 1, 2013. Beginning on May 1, 2013, the Partnership consolidated Enogex LLC and all previously combined entities.

/s/ Deloitte & Touche LLP

Houston, Texas
February 21, 2014

ENABLE MIDSTREAM PARTNERS, LP

COMBINED AND CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Revenues (including revenues from affiliates (Note 11))	$ 2,489	$ 952	$ 932
Cost of Goods Sold, excluding depreciation and amortization (including expenses from affiliates (Note 11))	1,313	129	101
Operating Expenses:			
Operation and maintenance (including expenses from affiliates (Note 11))	429	267	263
Depreciation and amortization	212	106	91
Impairment	12	—	—
Taxes other than income taxes	54	34	37
Total Operating Expenses	707	407	391
Operating Income	469	416	440
Other Income (Expense):			
Interest expense (including expenses from affiliates (Note 11))	(67)	(85)	(90)
Equity in earnings of equity method affiliates	15	31	31
Interest income—affiliated companies	9	21	14
Step acquisition gain	—	136	—
Total	(43)	103	(45)
Income Before Income Taxes	426	519	395
Income tax expense (benefit)	(1,192)	203	163
Net Income	$ 1,618	$ 316	$ 232
Less: Net income attributable to noncontrolling interest	3	—	—
Net Income attributable to Enable Midstream Partners, LP	$ 1,615	$ 316	$ 232
Limited partners' interest in net income attributable to Enable Midstream Partners, LP (Note 1)	$ 289	$ —	$ —
Number of outstanding limited partner units	499	—	—
Basic and diluted earnings per limited partner unit	$ 0.58	$ —	$ —

See Notes to the Combined and Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

COMBINED AND CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2013	**2012**	**2011**
	(In millions)		
Net Income	$ 1,618	$ 316	$ 232
Other comprehensive income	—	—	—
Comprehensive income	$ 1,618	$ 316	$ 232
Less: Comprehensive income attributable to noncontrolling interest	3	—	—
Comprehensive income attributable to Enable Midstream Partners, LP	$ 1,615	$ 316	$ 232

See Notes to the Combined and Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

COMBINED AND CONSOLIDATED BALANCE SHEETS

ASSETS	**December 31,**	
	2013	**2012**
Current Assets:	**(In millions)**	
Cash and cash equivalents	$ 108	$ —
Accounts receivable	306	78
Accounts receivable—affiliated companies	28	25
Notes receivable—affiliated companies	—	479
Inventory	83	57
Taxes receivable	—	45
Deferred income tax assets	—	31
Gas imbalances	10	—
Other current assets	14	24
Total current assets	549	739
Property, Plant and Equipment:		
Property, plant and equipment	9,655	5,175
Less: accumulated depreciation and amortization	665	470
Property, plant and equipment, net	8,990	4,705
Other Assets:		
Intangible assets, net	383	—
Goodwill	1,068	629
Investment in equity method affiliates	198	405
Other	44	4
Total other assets	1,693	1,038
Total Assets	$ 11,232	$ 6,482

See Notes to the Combined and Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

COMBINED AND CONSOLIDATED BALANCE SHEETS (Continued)

LIABILITIES AND PARTNERS' CAPITAL	**December 31, 2013**	**December 31, 2012**
	(In millions)	
Current Liabilities:		
Accounts payable	$ 400	$ 83
Accounts payable—affiliated companies	40	28
Current portion of long-term debt	204	—
Notes payable—affiliated companies	—	753
Taxes accrued	20	25
Gas imbalances	13	7
Other	43	26
Total current liabilities	720	922
Other Liabilities:		
Accumulated deferred income taxes, net	8	1,272
Notes payable—affiliated companies	363	1,009
Benefit obligations	—	21
Regulatory liabilities	16	16
Other	28	21
Total other liabilities	415	2,339
Long-Term Debt	1,916	—
Commitments and Contingencies (Note 12)		
Partners' Capital:		
Partners' Capital	8,148	3,221
Accumulated other comprehensive loss	–	(6)
Total Enable Midstream Partners, LP Partners' Capital	8,148	3,215
Noncontrolling interest	33	6
Total Partners' Capital	8,181	3,221
Total Liabilities and Partners' Capital	$ 11,232	$ 6,482

See Notes to the Combined and Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

COMBINED AND CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Cash Flows from Operating Activities:			
Net income	$ 1,618	$ 316	$ 232
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	212	106	91
Deferred income taxes	(1,194)	196	176
Impairments	12	—	—
Step acquisition gain	—	(136)	—
Gain on sale/retirement of assets	2	—	—
Equity in earnings of equity method affiliates, net of distributions	9	8	8
Changes in other assets and liabilities:			
Accounts receivable, net	(81)	(9)	45
Accounts receivable – affiliated companies	(4)	1	28
Inventory	(6)	2	13
Taxes receivable	19	(1)	13
Other current assets	15	(3)	10
Other assets	1	—	3
Accounts payable	62	(3)	7
Accounts payable – affiliated companies	3	(3)	(1)
Taxes accrued	—	(19)	21
Other current liabilities	(2)	(4)	(3)
Other liabilities	(18)	—	19
Net cash provided by operating activities	648	451	662
Cash Flows from Investing Activities:			
Capital expenditures, net of acquisitions	(573)	(202)	(346)
Acquisitions, net of cash	—	(360)	—
Decrease (increase) in notes receivable affiliated companies	434	(77)	(219)
Investment in equity method affiliates	—	(5)	(13)
Other, net	(1)	(1)	18
Net cash used in investing activities	(140)	(645)	(560)
Cash Flows from Financing Activities:			
Proceeds from long-term debt, net of issuance costs	1,046	—	—
Proceeds from line of credit	1,126	—	—
Repayment of line of credit	(754)	—	—
Increase (decrease) notes payable – affiliated companies	(1,542)	194	(102)
Repayment of advance with affiliated companies	(136)	—	—
Capital contributions from partners	43	—	—
Distribution to partners	(183)	—	—
Net cash provided by (used in) financing activities	(400)	194	(102)
Net Change in Cash and Cash Equivalents	108	—	—
Cash and Cash Equivalents at Beginning of the Year	—	—	—
Cash and Cash Equivalents at End of the Year	$ 108	$ —	$ —

See Notes to the Combined and Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

COMBINED AND CONSOLIDATED STATEMENTS OF CASH FLOWS, continued

	Year Ended December 31,		
	2013	2012	2011
	(In millions)		
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest, net of capitalized interest	$ 65	$ 85	$ 90
Income taxes (refunds), net	(9)	26	(67)
Non-cash transactions:			
Accounts payable related to capital expenditures	$ 43	$ 37	$ 31
Acquisition of Enogex (Note 3)	3,788	–	–

See Notes to the Combined and Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP

COMBINED AND CONSOLIDATED STATEMENTS OF ENABLE MIDSTREAM PARTNERS, LP PARENT NET EQUITY AND PARTNERS' CAPITAL

	Partners' Capital Units	Partners' Capital Value	Parent Net Investment Value	Accumulated Other Comprehensive Loss Value	Total Enable Midstream Partners, LP Partners' Capital Value	Noncontrolling Interest Value	Total Partners' Capital Value
	(In millions)						
Balance as of December 31, 2010	—	$ —	$ 2,672	$ (6)	$ 2,666	$ 6	$ 2,672
Net income	—	—	232	—	232	—	232
Balance as of December 31, 2011	—	$ —	$ 2,904	$ (6)	$ 2,898	$ 6	$ 2,904
Net income	—	—	316	—	316		316
Net transfers from parent	—	—	1	—	1	—	1
Balance as of December 31, 2012	—	$ —	$ 3,221	$ (6)	$ 3,215	$ 6	$ 3,221
Net income	—	—	1,326	—	1,326	—	1,326
Contributions from (Distributions to) CenterPoint Energy prior to formation (Note 1)	—	—	(295)	6	(289)	—	(289)
Balance as of April 30, 2013	—	$ —	$ 4,252	$ —	$ 4,252	$ 6	$ 4,258
Conversion to a limited partnership	291	4,252	(4,252)	—	—	—	—
Issuance of units upon acquisition of Enogex on May 1, 2013 (Note 3)	208	3,788	—	—	3,788	26	3,814
Net income	—	289	—	—	289	3	292
Distributions to Partners	—	(181)	—	—	(181)	(2)	(183)
Balance as of December 31, 2013	499	$ 8,148	$ —	$ —	$ 8,148	$ 33	$ 8,181

See Notes to the Combined and Consolidated Financial Statements

NOTES TO THE COMBINED AND CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Organization

Enable Midstream Partners, LP (Partnership) is a private limited partnership formed on May 1, 2013 by CenterPoint Energy, Inc. (CenterPoint Energy), OGE Energy Corp. (OGE Energy) and affiliates of ArcLight Capital Partners, LLC (ArcLight), pursuant to the terms of the Master Formation Agreement dated March 14,2013 (MFA). The Partnership is a large-scale, growth-oriented limited partnership formed to own, operate and develop strategically located natural gas and crude oil infrastructure assets. The Partnership's assets and operations are organized into two business segments: (i) Gathering and Processing, which primarily provides natural gas and crude oil gathering, processing and fractionation services for our producer customers, and (ii) Transportation and Storage, which provides interstate and intrastate natural gas pipeline transportation and storage service to natural gas producers, utilities and industrial customers. The natural gas gathering and processing assets are strategically located in four states and serve natural gas production in the Anadarko, Arkoma and Ark-La-Tex basins. This segment also includes an emerging crude oil gathering business in the Bakken shale formation, principally located in the Williston basin. The natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

As of December 31, 2013, CenterPoint Energy, OGE Energy and ArcLight hold approximately 58.3%, 28.5% and 13.2%, respectively, of the limited partner interests in the Partnership. The general partner of the Partnership is Enable GP, LLC (General Partner). The limited partner interests of the Partnership have limited voting rights on matters affecting the business. As such, limited partners do not have rights to elect the Partnership's General Partner on an annual or continuing basis and may not remove the Partnership's General Partner without at least 75% vote by all unitholders, including all units held by the Partnership's limited partners, and General Partner and its affiliates, voting together as a single class.

The Partnership is controlled equally by CenterPoint Energy and OGE Energy, who each have 50% of the management rights of the General Partner. The General Partner was established by CenterPoint Energy and OGE Energy to govern the Partnership and has no other operating activities. The General Partner is governed by a board made up of an equal number of representatives designated by each of CenterPoint Energy and OGE Energy, along with board members CenterPoint Energy and OGE Energy mutually agree to appoint. Based on the 50/50 management ownership, with neither company having control, effective May 1, 2013, CenterPoint Energy and OGE Energy deconsolidated their interests in the Partnership and Enogex LLC (Enogex), respectively. Effective July 30, 2013, the name of Enogex was changed to Enable Oklahoma Intrastate Transmission, LLC (Enable Oklahoma).

CenterPoint Energy and OGE Energy also own a 40% and 60% interest, respectively, in the incentive distribution rights held by the General Partner. In addition, for a period of time prior to an initial public offering, ArcLight will have protective approval rights over certain material activities of the Partnership, including material increases in capital expenditures and certain equity issuances, entering into transactions with related parties and acquiring, pledging or disposing of certain material assets.

Upon conversion to a limited partnership on May 1, 2013, the Partnership's earnings are no longer subject to income tax (other than Texas state margin taxes) and are taxable at the individual partner level. As a result of the conversion to a partnership immediately prior to formation, CenterPoint Energy assumed all outstanding current income tax liabilities and the Partnership derecognized the deferred income tax assets and liabilities by recording an income tax benefit of $1.24 billion. Consequently, the Combined and Consolidated Statements of Income do not include an income tax provision on income earned on or after May 1, 2013 (other than Texas state margin taxes). See Note 13 for further discussion of the Partnership's income taxes.

Prior to May 1, 2013, the financial statements of the Partnership include Enable Gas Transmission, LLC (EGT), Enable Mississippi River Transmission, LLC (MRT), and the non-rate regulated natural gas gathering, processing and treating operations (consisting of CenterPoint Energy Field Services, LLC and its subsidiaries), which were under common control by CenterPoint Energy, and a 50% interest in Southeast Supply Header, LLC (SESH). On May 1, 2013, CenterPoint Energy converted CenterPoint Energy Field Services, LLC, an indirect wholly owned subsidiary into a Delaware limited partnership, which subsequently changed its name to Enable Midstream Partners, LP.

As discussed in Note 1 under "Enable Midstream Partners, LP Parent Net Equity and Partners' Capital," through the Partnership formation on May 1, 2013, CenterPoint Energy retained certain assets and liabilities and related balances in accumulated other comprehensive loss, historically held by the Partnership, such as certain intercompany notes payable to CenterPoint Energy and benefit plan obligations. Additionally, the Partnership distributed a 25.05% interest in SESH to CenterPoint Energy, subject to future acquisition by the Partnership through put and call options discussed in Note 7. On May 1, 2013, OGE Energy and ArcLight indirectly contributed 100% of the equity interests in Enogex to the Partnership in exchange for limited partner interests and, for OGE Energy only, interests in the General Partner. The Partnership concluded that the Partnership formation on May 1, 2013 was considered a business combination, and for accounting purposes, the Partnership was the acquirer of Enogex. Subsequent to May 1, 2013, the financial statements of the Partnership are consolidated to reflect the acquisition of Enogex, and the remaining 24.95% interest in SESH. See Note 3 for further discussion of the acquisition of Enogex.

In addition, as of December 31, 2013, as a result of the acquisition of Enogex on May 1, 2013, the Partnership holds a 50% ownership interest in Atoka Midstream LLC (Atoka). As of December 31, 2013, the Partnership consolidated Atoka in its Combined and Consolidated Financial Statements as Enable Oklahoma acted as the managing member of Atoka and had control over the operations of Atoka.

On November 26, 2013, the Partnership filed a registration statement with the Securities and Exchange Commission for a proposed initial public offering of its common units, representing limited partner interests in the Partnership (the Offering). At the date of these financial statements, the registration statement relating to the Offering is not effective. The completion of the Offering is subject to numerous conditions and no assurances can be made that it will be successfully completed. The securities offered under the registration statement may not be sold, nor may offers to buy be accepted, prior to the time that the registration statement becomes effective. The information contained in these financial statements with respect to the Offering shall not constitute an offer to sell or a solicitation of an offer to buy any securities.

Basis of Presentation

These combined and consolidated financial statements and related notes of the Partnership have been prepared in accordance with accounting principles generally accepted in the United States. For accounting and financial reporting purposes, (i) the formation of the Partnership is considered a contribution of real estate by CenterPoint Energy and is reflected at CenterPoint Energy's historical cost as of May 1, 2013 and (ii) the Partnership acquired Enogex on May 1, 2013.

These combined and consolidated financial statements have been prepared from the historical accounting records maintained by CenterPoint Energy for the Partnership until May 1, 2013 and may not necessarily be indicative of the condition that would have existed or the results of operations if the Partnership had been operated as a separate and unaffiliated entity. All of Partnership's combined entities were under common control and management for the periods presented until May 1, 2013, and all intercompany transactions and balances are eliminated in combination and consolidation, as applicable. Beginning on May 1, 2013, the Partnership consolidated Enogex and all previously combined entities of the Partnership.

These combined and consolidated financial statements and the related financial statement disclosures reflect all normal recurring adjustments that are, in the opinion of management, necessary to present fairly the financial position and results of operations for the respective periods.

For a description of the Partnership's reportable business segments, see Note 14.

Enable Midstream Partners, LP Parent Net Equity and Partners' Capital

Prior to May 1, 2013, Enable Midstream Partners, LP Parent Net Equity on the Combined Balance Sheet represents the investment of CenterPoint Energy in the Partnership. On April 30, 2013 immediately prior to formation of the limited partnership, while under common control, CenterPoint Energy completed equity transactions with the Partnership, whereby CenterPoint Energy made a cash contribution to the Partnership and retained certain assets and liabilities previously held by the Partnership, all of which were deemed to be transfers of net assets not constituting a transfer of a business, as follows:

	Amounts retained prior to May 1, 2013	
	(In millions)	
Contributions from (Distributions to) CenterPoint Energy		
Cash	$	40
Pension and postretirement plans		22
Deferred financing cost		6
Investment in 25.05% of SESH (see Note 7)		(197)
Increase in Notes payable—affiliated companies (see Note 11)		(143)
Decrease in Notes receivable—affiliated companies (see Note 11)		(45)
Income tax obligations, net		28
Net distributions to CenterPoint Energy prior to formation	$	(289)

Effective May 1, 2013, Enable Midstream Partners, LP Partners' Capital on the Consolidated Balance Sheet represents the net amount of capital, accumulated net income, contributions and distributions affecting the investments of CenterPoint Energy, OGE Energy, and ArcLight in the Partnership. On August 14, 2013 and November 14, 2013, the Partnership distributed $61 million and $120 million to the unitholders of record as of July 1, 2013 and October 1, 2013, respectively.

Earnings per Limited Partner Unit

Earnings per limited partner unit is calculated by dividing the limited partners' interest in net income attributable to Enable Midstream Partners, LP by the weighted average number of limited partner units outstanding. Earnings per limited partner unit assumes that cash distributions are equal to the limited partners' interest in net income attributable to Enable Midstream Partners, LP. Limited partners' interest in net income attributable to Enable Midstream Partners, LP reflects net income attributable to Enable Midstream Partners, LP subsequent to its formation as a limited partnership on May 1, 2013, as no limited partner units were outstanding prior to this date. The and limited partner units that may be issued in connection with acquiring the additional 24.95% and 0.10% interests in SESH, respectively, as discussed in Note 7, are not included in the calculation of diluted earnings per limited partner unit as the impact of the potential transactions is anti-dilutive.

Use of Estimates

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Revenues

Revenues for gathering, processing, transportation and storage services for the Partnership are recorded each month based on the current month's estimated volumes, contracted prices (considering current commodity prices), historical seasonal fluctuations and any known adjustments. The estimates are reversed in the following month and customers are billed on actual volumes and contracted prices. Gas sales are calculated on current-month nominations and contracted prices. Revenues associated with the production of NGLs are estimated based on current-month estimated production and contracted prices. These amounts are reversed in the following month and the customers are billed on actual production and contracted prices. Estimated revenues are reflected in Accounts Receivable or Accounts Receivable-affiliated companies, as appropriate, on the Combined or Consolidated Balance Sheets and in Revenues on the Combined and Consolidated Statements of Income.

The Partnership recognizes revenue from natural gas gathering, processing, transportation and storage services to third parties as services are provided. Revenue associated with NGLs is recognized when the production is sold. The partnership records deferred revenue when it receives consideration from a third party before achieving certain criteria that must be met for revenue to be recognized in accordance with GAAP. The Partnership has $9 million and $-0- million of deferred revenues on the Consolidated and Combined Balance Sheets as of December 31, 2013 and 2012, respectively.

The Partnership relies on certain key natural gas producer customers for a significant portion of natural gas and NGLs supply. The Partnership relies on certain key utilities for a significant portion of transportation and storage demand. The Partnership depends on third-party facilities to transport and fractionate NGLs that it delivers to third parties at the inlet of their facilities. Additionally for the year ended December 31,2013, one third party purchases approximately 30% of the NGLs delivered to its system, which accounted for approximately $232 million or 9% of total revenue. Other than revenues from affiliates discussed in Note 11, there are no other revenue concentrations with individual customers in the year ended December 31, 2013, 2012 and 2011.

Natural Gas Purchases

Estimates for gas purchases are based on estimated volumes and contracted purchase prices. Estimated gas purchases are included in Accounts Payable or Accounts Payable-affiliated companies, as appropriate on the Combined or Consolidated Balance Sheets and in Cost of Goods Sold, excluding Depreciation and Amortization on the Combined and Consolidated Statements of Income.

Environmental Costs

The Partnership expenses or capitalizes environmental expenditures, as appropriate, depending on their future economic benefit. The Partnership expenses amounts that relate to an existing condition caused by past operations that do not have future economic benefit. The Partnership records undiscounted liabilities related to these future costs when environmental assessments and/or remediation activities are probable and the costs can be reasonably estimated. There are no material amounts accrued at December 31, 2013 or 2012.

Depreciation and Amortization Expense

Depreciation is computed using the straight-line method based on economic lives or a regulatory-mandated recovery period. Amortization of intangible assets is computed using the straight-line method over the respective lives of the intangible assets.

During 2013, the Partnership completed a depreciation study for the Gathering and Processing segment, as well as the acquired Enogex assets. The new depreciation rates have been applied prospectively. There were no material changes in weighted average useful lives for pre-acquisition Gathering and Processing assets.

Income Taxes

Prior to May 1, 2013, the Partnership was included in the consolidated income tax returns of CenterPoint Energy. The Partnership calculated its income tax provision on a separate return basis under a tax sharing agreement with CenterPoint Energy. The Partnership used the asset and liability method of accounting for deferred income taxes in accordance with accounting guidance for income taxes. Deferred income tax assets and liabilities were recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. A valuation allowance was established against deferred tax assets for which management believed realization was not considered more likely than not. Current federal and certain state income taxes were payable to or receivable from CenterPoint Energy. The Partnership recognized interest and penalties as a component of income tax expense. Upon conversion to a limited partnership on May 1, 2013, the Partnership’s earnings are no longer subject to income tax (other than Texas state margin taxes) and are taxable at the individual partner level. For more information, see Note 13.

Cash and Cash Equivalents

The Partnership considers cash equivalents to be short-term, highly liquid investments with maturities of three months or less from the date of purchase. The Combined or Consolidated Balance Sheets have $108 million and $-0- million of cash and cash equivalents as of December 31, 2013 and 2012, respectively.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount and do not bear interest. It is the policy of management to review the outstanding accounts receivable monthly, as well as the bad debt write-offs experienced in the past. Based on this review, management determined that no allowance for doubtful accounts was required as of December 31, 2013 and 2012.

Inventory

Materials and supplies inventory is valued at cost and is subsequently recorded at the lower of cost or market. During the year ended December 31, 2013, the Partnership recorded write-downs to market value related to materials and supplies inventory of $2 million associated with the Service Star business line impairment discussed in Note 9. No such write-downs were recorded in the years ended December 31, 2012 and 2011. Materials and supplies are recorded to inventory when purchased and, as appropriate, subsequently charged to Operation and maintenance expense on the Combined and Consolidated Statements of Income or capitalized to Property, plant and equipment on the Combined or Consolidated Balance Sheets when installed.

Natural gas inventory is held, through the Transportation and Storage business segment, to provide operational support for the intrastate pipeline deliveries and to manage leased intrastate storage capacity. Natural gas liquids inventory is held, through the Gathering and Processing business segment, due to timing differences between the production of certain natural gas liquids and ultimate sale to third parties. Natural gas and natural gas liquids inventory is valued using moving average cost and is subsequently recorded at the lower of cost or market. During the year ended December 31, 2013, the Partnership recorded write-downs to market value related to natural gas and natural gas liquids inventory of $4 million. No such write-downs were recorded in the years ended December 31, 2012 and 2011. The cost of gas associated with sales of natural gas and natural gas liquids inventory is presented in Cost of goods sold, excluding depreciation and amortization on the Combined and Consolidated Statements of Income.

	December 31,	
	2013	**2012**
	(In millions)	
Materials and supplies	$ 60	$ 56
Natural gas inventory	23	1
Total inventory	$ 83	$ 57

Gas Imbalances

Gas imbalances occur when the actual amounts of natural gas delivered from or received by the Partnership's pipeline system differ from the amounts scheduled to be delivered or received. Imbalances are due to or due from shippers and operators and can be settled in cash or made up in-kind depending on contractual terms. The Partnership values all imbalances at individual, or where appropriate an average of, current market indices applicable to the Partnership's operations, not to exceed net realizable value.

Long-Lived Assets (including Intangible Assets)

The Partnership records property, plant and equipment and intangible assets at historical cost. The Partnership expenses repair and maintenance costs as incurred.

Assessing Impairment of Long-lived Assets (including Intangible Assets) and Goodwill

The Partnership periodically evaluates long-lived assets, including property, plant and equipment, and specifically identifiable intangibles other than goodwill, when events or changes in circumstances indicate that the carrying value of these assets may not be recoverable. The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets.

The Partnership assesses its goodwill for impairment at least annually and evaluates goodwill when events or changes in circumstances indicate that its carrying value may not be recoverable by comparing the fair value of the reporting unit with its book value, including goodwill. The Partnership tested its goodwill for impairment on May 1, 2013 upon formation and following formation tests annually on October 1. The Partnership utilizes the market or income approaches to estimate the fair value of the reporting unit, also giving consideration to the alternative cost approach. Under the market approach, historical and current year forecasted cash flows are multiplied by a market multiple to determine fair value. Under the income approach, anticipated cash flows over a period of years plus a terminal value are discounted to present value using appropriate discount rates. If the estimated fair value of the reporting unit is less than the carrying amount of the reporting unit, then a second step must be completed in order to determine the amount of the goodwill impairment that should be recorded. In the second step, the implied fair value of the reporting unit's goodwill is determined by allocating the reporting unit's fair value to all of its assets and liabilities other than goodwill (including any unrecognized intangible assets) in a manner similar to a purchase price allocation. The resulting implied fair value of the goodwill that results from the application of this second step is then compared to the carrying amount of the goodwill and an impairment charge is recorded for the difference. The Partnership performs its goodwill impairment testing one level below the Transportation and Storage and Gathering and Processing business segment level at the operating segment level.

Regulatory Assets and Liabilities

The Partnership applies the guidance for accounting for regulated operations to portions of the Transportation and Storage business segment. The Partnership's rate-regulated businesses recognize removal costs as a component of depreciation expense in accordance with regulatory treatment. As of each of December 31, 2013 and 2012, these removal costs of $16 million are classified as regulatory liabilities in the Combined or Consolidated Balance Sheets.

Capitalization of Interest and Allowance for Funds Used During Construction

Allowance for funds used during construction (AFUDC) represents the approximate net composite interest cost of borrowed funds and a reasonable return on the equity funds used for construction. Although AFUDC increases both utility plant and earnings, it is realized in cash when the assets are included in rates for combined entities that apply guidance for accounting for regulated operations. Interest and AFUDC are capitalized as a component of projects under construction and will be amortized over the assets' estimated useful lives. During the year ended December 31, 2013, 2012 and 2011, the Partnership capitalized interest and AFUDC of $7 million, $2 million and $-0- million, respectively.

Derivative Instruments

The Partnership is exposed to various market risks. These risks arise from transactions entered into in the normal course of business. At times, the Partnership utilizes derivative instruments such as physical forward contracts to mitigate the impact of changes in commodity prices on its operating results and cash flows. Such derivatives are recognized in the Partnership's Combined or Consolidated Balance Sheets at their fair value unless the Partnership elects the normal purchase and sales exemption for qualified physical transactions. A derivative may be designated as a normal purchase or normal sale if the intent is to physically receive or deliver the product for use or sale in the normal course of business.

The Partnership's policies prohibit the use of leveraged financial instruments. A leveraged financial instrument, for this purpose, is a transaction involving a derivative whose financial impact will be based on an amount other than the notional amount or volume of the instrument.

Fair Value Measurements

The Partnership determines fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. As required, the Partnership utilizes valuation techniques that maximize the use of observable inputs (levels 1 and 2) and minimize the use of unobservable inputs (level 3) within the fair value hierarchy included in current accounting guidance. The Partnership generally applies the market approach to determine fair value. This method uses pricing and other information generated by market transactions for identical or comparable assets and liabilities. Assets and liabilities are classified within the fair value hierarchy based on the lowest level (least observable) input that is significant to the measurement in its entirety.

Accumulated Other Comprehensive Loss

There were no material changes in the components of accumulated other comprehensive loss attributable to the Partnership during the year ended December 31, 2013. At both December 31, 2013 and 2012, there was no accumulated other comprehensive loss related to the Partnership's noncontrolling interest.

No significant amounts were reclassified out of accumulated other comprehensive loss to net income during the year ended December 31, 2013, 2012 and 2011.

(2) New Accounting Pronouncements

In February 2013, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update No. 2013-02, "Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income" (ASU 2013-02). The objective of ASU 2013-02 is to improve the transparency of changes in other comprehensive income and items reclassified out of Accumulated Other Comprehensive Income in financial statements. This new guidance is effective for a reporting entity's first reporting period beginning after December 15, 2012 and should be applied prospectively. The Partnership's adoption of this new guidance on January 1, 2013 did not have a material impact on its financial position, results of operations or cash flows.

In December 2011 and January 2013, the FASB issued Accounting Standards Update No. 2011-11, "Disclosures About Offsetting Assets and Liabilities" (ASU 2011-11) and No. 2013-01, "Clarifying the Scope of Disclosures About Offsetting Assets and Liabilities" (ASU 2013-01), respectively. The objective of ASU 2011-11 is to enhance disclosures about the nature of an entity's rights of setoff and related arrangements associated with its financial instruments and derivative instruments. The objective of ASU 2013-01 is to clarify which instruments and transactions are subject to ASU 2011-11. Both ASU 2011-11 and ASU 2013-01 are effective for a reporting entity's first reporting period beginning on or after January 1, 2013 and should be applied retrospectively. The Partnership's adoption of this new guidance on January 1, 2013 did not have a material impact on its combined and consolidated financial position, results of operations or cash flows.

Management believes that other recently issued standards, which are not yet effective, will not have a material impact on the Partnership's combined or consolidated financial position, results of operations or cash flows upon adoption.

(3) Acquisition of Enogex

Under the acquisition method, the fair value of the consideration transferred by the Partnership to OGE Energy and ArcLight for the contribution of Enogex in exchange for interest in the Partnership is allocated to the assets acquired and liabilities assumed on May 1, 2013 based on their estimated fair value. Enogex's assets, liabilities and equity are recorded at their estimated fair value as of May 1, 2013, and beginning on May 1, 2013, the Partnership consolidated Enogex. The Partnership completed the purchase price allocation for this transaction in the fourth quarter of 2013.

On May 1, 2013, in accordance with the MFA, CenterPoint Energy, OGE Energy, and ArcLight received 291,002,583 common units, 141,956,176 common units, and 65,908,224 common units, respectively representing limited partner interests in the Partnership. The fair value of consideration transferred to OGE Energy and ArcLight in exchange for the contribution of Enogex consists of the fair value of the limited and general partner interests. The Partnership utilized the market approach to estimate the fair value of the limited partner interests, general partner interests and Atoka, also giving consideration to alternative methods such as the income and cost approaches as it relates to the underlying assets and liabilities. The primary inputs for the market valuation are the historical and current year forecasted cash flows and market multiples. The primary inputs for the income approach are forecasted cash flows and discount rates. The primary inputs for the cost approach are costs for similar assets and ages of the assets. All fair value measurements of assets acquired and liabilities assumed are based on a combination of inputs that are not observable in the market and thus represent Level 3 inputs.

The Partnership incurred no acquisition related costs in the Combined and Consolidated Statement of Income based upon the terms in the MFA related to the acquisition of Enogex.

The following table summarizes the amounts recognized by the Partnership for the estimated fair value of assets acquired and liabilities assumed for the acquisition of 100% interest Enogex as of May 1, 2013 and is reconciled to the consideration transferred by the Partnership (in millions):

	Amounts Recognized as of May 1, 2013
Assets	
Current Assets	$ 192
Property, plant and equipment	3,919
Goodwill	439
Other intangible assets	401
Other assets	21
Total assets	$ 4,972
Liabilities	
Current Liabilities	$ 393
Long-term debt	745
Other liabilities	20
Total liabilities	1,158
Less: Noncontrolling interest at fair value	26
Fair value of consideration transferred	$ 3,788

The amounts of Enogex's revenue, operating income, net income and net income attributable to Enable Midstream Partners, LP included in the Partnership's Combined and Consolidated Statement of Income for the period from May 1, 2013 through December 31, 2013 are as follows (in millions):

Revenues	$ 1,406
Operating income	$ 92
Net income	$ 77
Net income attributable to Enable Midstream Partners, LP	$ 74

See Note 7 for discussion of the Partnership's acquisition of Waskom during 2012.

Impact on Depreciation

The property, plant and equipment acquired from Enogex have differing weighted average useful lives from the existing assets of the Partnership. These assets will be depreciated over a weighted average estimated useful life of 32 years.

Unaudited Pro forma Results of Operations

The Partnership's unaudited pro forma results of operations in the combined entity had the acquisition of Enogex been completed on January 1, 2012 are as follows (in millions):

	Year ended December 31, 2013	Year ended December 31, 2012
Unaudited pro forma results of operations:		
Pro forma revenues	$ 3,120	$ 2,563
Pro forma operating income	$ 487	$ 558
Pro forma net income	$ 1,638	$ 433
Pro forma net income attributable to Enable Midstream Partners, LP	$ 1,635	$ 431

The unaudited pro forma results of operations include adjustments to:

- Include the historical results of Enogex beginning on January 1, 2012;
- Include incremental depreciation and amortization incurred on the step-up of Enogex's assets;
- Include adjustments to revenue and cost of sales to reflect Enogex purchase price adjustments for the recurring impact of certain loss contracts and deferred revenues; and
- Include a reduction to interest expense for recognition of a premium on Enogex's fixed rate senior notes.

The unaudited pro forma information is not necessarily indicative of the results of operations that would have occurred had the transactions been made at the beginning of the periods presented or the future results of the consolidated operations.

(4) Property, Plant and Equipment

Property, plant and equipment includes the following:

	Weighted Average Useful Lives (Years)	December 31, 2013	December 31, 2012
		(In millions)	
Property, plant and equipment, gross:			
Gathering and Processing	35	$ 5,123	$ 2,339
Transportation and Storage	42	4,300	2,772
Construction work-in-progress		232	64
Total		$ 9,655	$ 5,175
Accumulated depreciation:			
Gathering and Processing		213	118
Transportation and Storage		452	352
Total accumulated depreciation		665	470
Property, plant and equipment, net		$ 8,990	$ 4,705

(5) Intangible Assets, Net

Prior to May 1, 2013, the Partnership did not have any intangible assets. Associated with the acquisition of Enogex, the Partnership recorded $401 million in intangible assets associated with customer relationships. Intangible assets are as follows as of December 31, 2013 (in millions):

	Acquisition of Enogex	Accumulated Amortization	Net Intangible Assets
Customer relationships	$ 401	$ 18	$ 383
Total	$ 401	$ 18	$ 383

The Partnership determined that intangible assets have a weighted average useful life of 15 years for customer relationships as of May 1, 2013. Intangible assets do not have any significant residual value or renewal options of existing terms. There are no intangible assets with indefinite useful lives.

Amortization expense in the year ended December 31, 2013 is $18 million. The following table summarizes the Partnership's expected amortization of intangible assets for each of the next five years (in millions).

	2014	2015	2016	2017	2018
Expected amortization of intangible assets	$ 27	$ 27	$ 27	$ 27	$ 27

(6) Goodwill

The excess of the consideration transferred over the fair value of the net assets acquired is allocated to goodwill. The goodwill arising from the acquisition of Enogex consists largely of the synergies and economies of scale expected from combining the operations of the Partnership and Enogex. The Partnership determined that its reporting units are one level below the Gathering and Processing and Transportation and Storage business segment level at the operating segment level.

Goodwill by reportable segment is as follows (in millions):

	Gathering and Processing	Transportation and Storage	Total
Balance at January 1	$ 26	$ 579	$ 605
Acquisition of Waskom	24	—	24
Balance at December 31, 2012	$ 50	$ 579	$ 629
Acquisition of Enogex	439	–	439
Balance at December 31, 2013	$ 489	$ 579	$ 1,068

The Partnership does not amortize goodwill but instead annually assesses goodwill for impairment. The Partnership performed an interim test upon formation as a limited partnership on May 1, 2013 and its annual impairment tests in the fourth quarter of 2013 and the third quarters of 2012 and 2011. The Partnership determined that no impairment charge for goodwill was required for the years ended December 31, 2013, 2012 and 2011. See Note 1 for further discussion regarding goodwill impairment testing.

(7) Investments in Equity Method Affiliates

The Partnership uses the equity method of accounting for investments in entities in which it has an ownership interest between 20% and 50% and exercises significant influence. Until May 1, 2013, the Partnership held a 50% investment in SESH, a 270-mile interstate natural gas pipeline, which was accounted for as an investment in equity method affiliates. On May 1, 2013, the Partnership distributed a 25.05% interest in SESH to CenterPoint Energy, retaining a 24.95% interest in SESH.

Following the distribution of SESH, CenterPoint Energy indirectly owns a 25.05% interest in SESH that may be contributed to Partnership in the future, upon exercise of certain put or call rights, under which CenterPoint Energy would contribute to the Partnership CenterPoint Energy’s retained interest in SESH at a price equal to the fair market value of such interest at the time the put right or call right is exercised (which may be no earlier than May 2014 and May 2015 for 24.95% and 0.1% interest, respectively). If CenterPoint Energy were to exercise such put right or the Partnership were to exercise such call right, CenterPoint Energy’s retained interest in SESH would be contributed to the Partnership in exchange for consideration consisting of and limited partnership units (subject to certain adjustments) for 24.95% and 0.1% interest in SESH, respectively, and, subject to certain restrictions, a cash payment, payable either from CenterPoint Energy to the Partnership or from the Partnership to CenterPoint Energy, in an amount such that the total consideration exchanged is equal in value to the fair market value of the contributed interest in SESH, subject to adjustment for accretion and dilution events. Affiliates of Spectra Energy Corp. own the remaining 50% interest in SESH.

Prior to July 2012, the Partnership owned a 50% interest in Waskom, a natural gas processing plant, which was accounted as an investment in equity method affiliates.

On July 31, 2012, the Partnership purchased the 50% interest that it did not already own in Waskom, as well as other gathering and related assets from a third-party for approximately $273 million in cash. The amount of the purchase price allocated to the acquisition of the 50% interest in Waskom was approximately $201 million, with the remaining purchase price allocated to the other gathering assets. The $273 million purchase price was allocated to the fair value of assets received as follows: $253 million to property, plant and equipment; $16 million to goodwill; and the remaining balance to other assets and liabilities. The original 50% interest held by Partnership in Waskom had a fair value of approximately $201 million prior to its acquisition of the additional 50% interest in Waskom, based on a discounted cash flow methodology (a level 3 valuation technique for which the key inputs are the discount rate and operating cash flow projections). The purchase of the additional 50% interest in Waskom was determined to be a business combination achieved in stages, and as such the

Partnership recorded a pre-tax gain of approximately $136 million and goodwill of $8 million on July 31, 2012, which is the result of Partnership remeasuring its original 50% interest in Waskom to fair value. As a result of the purchase, Partnership combined its wholly owned investment in Waskom beginning on July 31, 2012, which included goodwill totaling $24 million, consisting of $17 million related to Waskom (including the re-measurement of its existing 50% interest) and $7 million related to the other gathering and related assets. On May 1, 2013, CenterPoint Energy contributed a 100% interest in Waskom to the Partnership.

Investment in Equity Method Affiliates:

	December 31, 2013	December 31, 2012
	(In millions)	
SESH	$ 198	$ 404
Other	—	1
Total	$ 198	$ 405

Equity in Earnings of Equity Method Affiliates:

	Year Ended December 31, 2013 (1)	2012 (2)	2011
	(In millions)		
Waskom	$ —	$ 5	$ 10
SESH	15	26	21
Total	$ 15	$ 31	$ 31

(1) Until May 1, 2013, the combined results of operations for Partnership reflect a 50% interest in SESH, as historically combined in the Partnership's financial statements. On May 1, 2013, the Partnership distributed a 25.05% interest in SESH to CenterPoint Energy, retaining a 24.95% interest in SESH.

(2) On July 31, 2012, Waskom became a wholly owned subsidiary of the Partnership. Beginning on August 1, 2012, Waskom's operating results are combined or consolidated, as appropriate, in the Combined and Consolidated Statement of Income

Summarized financial information of SESH is presented below:

	December 31, 2013	December 31, 2012
Balance Sheets:	(In millions)	
Current assets	$ 53	$ 51
Property, plant and equipment, net	1,132	1,147
Other non-current assets	—	1
Total assets	$ 1,185	$ 1,199
Current liabilities	$ 20	$ 19
Non-current liabilities	375	377
Member's equity	790	803
Total liabilities and member's equity	$ 1,185	$ 1,199
Reconciliation:		
Investment in SESH	$ 198	$ 404
Less: Capitalized interest on investment in SESH	(1)	(2)
The Partnership's share of member's equity	$ 197	$ 402

	Year Ended December 31,		
	2013	2012	2011
Income Statements:	(In millions)		
Revenues	$ 107	$ 110	$ 100
Operating income	66	71	61
Net income	47	52	42

(8) Debt

Prior to May 1, 2013, the Partnership's debt was all payable to affiliates, which is discussed in Note 11 as notes payable—affiliated companies. The Partnership's third party debt effective May 1, 2013 is as follows:

On May 1, 2013, the Partnership entered into a $1.05 billion three-year senior unsecured term loan facility (Term Loan Facility), the proceeds of which were used to repay $1.05 billion of intercompany indebtedness owed to CenterPoint Energy. A wholly owned subsidiary of CenterPoint Energy has guaranteed collection of the Partnership's obligations under the Term Loan Facility, which guarantee is subordinated to all senior debt of such wholly owned subsidiary of CenterPoint Energy.

On May 1, 2013, the Partnership also entered into a $1.4 billion, five-year senior unsecured revolving credit facility (Revolving Credit Facility) in accordance with the terms of the MFA, discussed in Note 1. As of December 31, 2013, there was $333 million in principal advances and $2 million in letters of credit outstanding under the Revolving Credit Facility.

The Term Loan Facility and the Revolving Credit Facility each permit outstanding borrowings to bear interest at the London Interbank Offered Rate (LIBOR) and/or an alternate base rate, at the Partnership's election, plus an applicable margin. The applicable margin is based on the Partnership's applicable credit ratings. As of December 31, 2013, the applicable margin for LIBOR-based borrowings under the Term Loan Facility and the Revolving Credit Facility was 1.625% based on the Partnership's credit ratings. In addition, the Revolving Credit Facility requires the Partnership to pay a fee on unused commitments. The commitment fee is based on the Partnership's applicable credit rating from the rating agencies. As of December 31, 2013, the commitment fee under the Revolving Credit Facility was 0.25% per annum based on the Partnership's credit ratings.

Effective May 1, 2013, the Partnership's debt includes Enable Oklahoma's $200 million of 6.875% senior notes due July of 2014 and $250 million of 6.25% senior notes due March of 2020 (collectively, the Enable Oklahoma Senior Notes). The Enable Oklahoma Senior Notes have a $37 million unamortized premium at December 31, 2013, of which $4 million relates to the senior notes due July of 2014 and $33 million relates to the senior notes due March of 2020, resulting in an effective interest rate of 3.39% and 3.77%, respectively, during the year ended December 31, 2013. Additionally, the Partnership's debt includes Enable Oklahoma's $250 million variable rate term loan (Enable Oklahoma Term Loan). The Enable Oklahoma Term Loan permits outstanding borrowings to bear interest at the London Interbank Offered Rate (LIBOR) and/or an alternate base rate, at Enable Oklahoma's election, plus an applicable margin. The applicable margin is based on Enable Oklahoma's applicable credit ratings. As of December 31, 2013, the applicable margin for LIBOR-based borrowings under the Enable Oklahoma Term Loan was 1.50% based on Enable Oklahoma's credit ratings.

Maturities of long-term debt, excluding unamortized premiums, are as follows:

	Long-term debt
2014	$ 200
2015	250
2016	1,050
2017	—
2018	333
Thereafter	250

Unamortized debt expense of $9 million and $-0- million at December 31, 2013 and 2012, respectively, is classified in Other assets in the Combined or Consolidated Balance Sheets and is being amortized over the life of the respective debt using the effective interest method. Unamortized premium on long-term debt of $37 million and $-0- million as of December 31, 2013 and 2012, respectively, is classified as either Long-term debt or Current portion of long-term debt, consistent with the underlying debt instrument, in the Combined or Consolidated Balance Sheets and is being amortized over the life of the respective debt using the effective interest method.

As of December 31, 2013, the Partnership and Enable Oklahoma complied with all of their debt agreements, including financial covenants.

(9) Fair Value Measurements

Certain assets and liabilities are recorded at fair value in the Combined or Consolidated Balance Sheets and are categorized based upon the level of judgment associated with the inputs used to measure their value. Hierarchical levels, as defined below and directly related to the amount of subjectivity associated with the inputs to fair valuations of these assets and liabilities are as follows:

Level 1: Inputs are unadjusted quoted prices in active markets for identical assets or liabilities at the measurement date. Instruments classified as Level 1 include natural gas futures, swaps and options transactions for contracts traded on the New York Mercantile Exchange (NYMEX) and settled through a NYMEX clearing broker.

Level 2: Inputs, other than quoted prices included in Level 1, are observable for the asset or liability, either directly or indirectly. Level 2 inputs include quoted prices for similar instruments in active markets, and inputs other than quoted prices that are observable for the asset or liability. Fair value assets and liabilities that are generally included in this category are derivatives with fair values based on inputs from actively quoted markets. Instruments classified as Level 2 include over-the-counter NYMEX natural gas swaps, natural gas basis swaps and natural gas purchase and sales transactions in markets such that the pricing is closely related to the NYMEX pricing, and over-the-counter West Texas Intermediate (WTI) crude swaps for condensate sales.

Level 3: Inputs are unobservable for the asset or liability, and include situations where there is little, if any, market activity for the asset or liability. Unobservable inputs reflect the Partnership’s judgments about the assumptions market participants would use in pricing the asset or liability since limited market data exists. The Partnership develops these inputs based on the best information available, including the Partnership’s own data.

The Partnership utilizes the market approach in determining the fair value of its derivative positions by using either NYMEX or WTI published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX published market prices may be considered Level 1 if they are settled through a NYMEX clearing broker account with daily margining. Over-the-counter derivatives with NYMEX or WTI based prices are considered Level 2 due to the impact of counterparty credit risk. Valuations based on independent broker pricing or broker/dealer valuations may be classified as Level 2 only to the extent they may be validated by an additional source of independent market data for an identical or closely related active market. In certain less liquid markets or for longer-term contracts, forward prices are not as readily available. In these circumstances, contracts are valued using internally developed methodologies that consider historical relationships among various quoted prices in active markets that result in management’s best estimate of fair value. These contracts are classified as Level 3.

The Partnership determines the appropriate level for each financial asset and liability on a quarterly basis and recognizes transfers between levels at the end of the reporting period. For the year ended December 31, 2013, there were no transfers between Level 1 and 2 and no Level 3 investments were held.

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

Estimated Fair Value of Financial Instruments

The fair values of all accounts receivable, notes receivable, accounts payable, short-term notes payable— affiliated companies, and other such financial instruments on the Combined and Consolidated Balance Sheets are estimated to be approximately equivalent to their carrying amounts and have been excluded from the table below. The following table summarizes the fair value and carrying amount of the Partnership’s financial instruments at December 31, 2013 and 2012 (in millions). The Company had no material financial instruments measured at fair value on a recurring basis at December 31, 2013 and 2012.

	December 31,			
	2013		2012	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long Term Debt:	(In millions)			
Long-term notes payable—affiliated companies (Level 2)	$ 363	$ 363	$ 1,009	$ 1,232
Revolving Credit Facility (Level 2)	333	333	—	—
Term Loan Facility (Level 2)	1,050	1,050	—	—
Enable Oklahoma Term Loan (Level 2)	250	250	—	—
Enable Oklahoma Senior Notes (Level 2)(1)	487	477	—	—

(1) Includes $204 million of current portion as of December 31, 2013.

The fair value of the Partnership's Term Loan Facility and Long-term notes payable—affiliated companies, along with the Enable Oklahoma Senior Notes, is based on quoted market prices and estimates of current rates available for similar issues with similar maturities and is classified as Level 2 in the fair value hierarchy.

Non-Financial Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis; that is, the assets and liabilities are not measured at fair value on an ongoing basis, but are subject to fair value adjustments in certain circumstances (e.g., when there is evidence of impairment).

During the year ended December 31, 2013, the Partnership remeasured the Service Star assets at fair value. Upon formation as a private partnership on May 1, 2013, management of the Partnership reassessed the long-term strategy related to the Service Star business line, a component of the Gathering and Processing business segment which provides measurement and communication services to third parties. Based on forecasted future undiscounted cash flows management determined that the carrying value of the Service Star assets were not fully recoverable. The Partnership utilized the income approach (generally accepted valuation approach) to estimate the fair value of these assets. The primary inputs are forecast cash flows and the discount rate. The fair value measurement is based on inputs that are not observable in the market and thus represent level 3 inputs. Applying a discounted cash flow model to the property, plant and equipment and reviewing the associated materials and supplies inventory, during the year ended December 31, 2013 the Partnership recognized a $12 million impairment, consisting of a $10 million write-down of property, plant and equipment and a $2 million write-down of materials and supplies inventory considered either excess or obsolete.

At December 31, 2012, no material fair value adjustments or fair value measurements were required for these non-financial assets or liabilities.

Contracts with Master Netting Arrangements

Fair value amounts recognized for forward, interest rate swap, option and other conditional or exchange contracts executed with the same counterparty under a master netting arrangement may be offset. The reporting entity's choice to offset or not must be applied consistently. A master netting arrangement exists if the reporting entity has multiple contracts, whether for the same type of conditional or exchange contract or for different types of contracts, with a single counterparty that are subject to a contractual agreement that provides for the net settlement of all contracts through a single payment in a single currency in the event of default on or termination of any one contract. Offsetting the fair values recognized for forward, interest rate swap, option and other conditional or exchange contracts outstanding with a single counterparty results in the net fair value of the transactions being reported as an asset or a liability in the Combined or Consolidated Balance Sheets. The Partnership has presented the fair values of its derivative contracts under master netting agreements using a net fair value presentation. The Partnership had no material commodity contracts recorded at fair value on its Combined or Consolidated Balance Sheet at December 31, 2013 and 2012.

The following tables summarize the Partnership's assets and liabilities that are measured at fair value on a recurring basis at December 31, 2013 (in millions):

	Gas Imbalances[(A)]	
	Assets[(B)]	**Liabilities[(C)]**
Significant other observable inputs (Level 2)	$ 8	$ 10

(A) The Partnership uses the market approach to fair value its gas imbalance assets and liabilities at individual, or where appropriate an average of, current market indices applicable to the Partnership's operations, not to exceed net realizable value. Gas imbalances held by Enable Oklahoma are valued using an average of the Inside FERC Gas Market Report for Panhandle Eastern Pipe Line Co. (Texas, Oklahoma Mainline), ONEOK (Oklahoma) and ANR Pipeline (Oklahoma) indices. There were no netting adjustments as of December 31, 2013.

(B) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of $2 million at December 31, 2013, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

(C) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of $3 million at December 31, 2013, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

The Partnership has no material assets or liability measured at fair value on a recurring basis at December 31, 2012.

(10) Derivative Instruments and Hedging Activities

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

Commodity Price Risk

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

- NGL put options and NGL swaps are used to manage the Partnership's NGL exposure associated with its processing agreements;
- natural gas swaps are used to manage the Partnership's keep-whole natural gas exposure associated with its processing operations and the Partnership's natural gas exposure associated with operating its gathering, transportation and storage assets; and
- natural gas futures and swaps, natural gas options and natural gas commodity purchases and sales are used to manage the Partnership's natural gas exposure associated with its storage and transportation contracts and asset management activities.

Normal purchases and normal sales contracts are not recorded in the Combined or Consolidated Balance Sheets and earnings are recognized in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales treatment to: (i) commodity contracts for the purchase and sale of natural gas used in or produced by the Partnership's operations and (ii) commodity contracts for the purchase and sale of NGLs produced by Partnership's Gathering and Processing segment.

The Partnership recognizes its non-exchange traded derivative instruments in the Combined or Consolidated Balance Sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. Exchange traded transactions are settled on a net basis daily through margin accounts with a clearing broker and, therefore, are recorded at fair value on a net basis in Other current assets in the Combined or Consolidated Balance Sheets.

Credit Risk

The Partnership is exposed to certain credit risks relating to its ongoing business operations. Credit risk includes the risk that counterparties that owe the Partnership money or energy will breach their obligations. If the counterparties to these arrangements fail to perform, the Partnership may be forced to enter into alternative arrangements. In that event, Partnership's financial results could be adversely affected and the Partnership could incur losses.

Cash Flow Hedges

For derivatives that are designated and qualify as a cash flow hedge, the effective portion of the change in fair value of the derivative instrument is reported as a component of Accumulated other comprehensive income (loss) and recognized into earnings in the same period during which the hedged transaction affects earnings. The ineffective portion of a derivative's change in fair value or hedge components excluded from the assessment of effectiveness is recognized currently in earnings. The Partnership measures the ineffectiveness of commodity cash flow hedges using the change in fair value method whereby the change in the expected future cash flows designated as the hedge transaction are compared to the change in fair value of the hedging instrument. Forecasted transactions, which are designated as the hedged transaction in a cash flow hedge, are regularly evaluated to assess whether they continue to be probable of occurring. If the forecasted transactions are no longer probable of occurring, hedge accounting will cease on a prospective basis and all future changes in the fair value of the derivative will be recognized directly in earnings.

The Partnership designates as cash flow hedges derivatives used to manage commodity price risk exposure for the Partnership'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). The Partnership also designates as cash flow hedges certain derivatives used to manage natural gas commodity exposure for certain natural gas storage inventory positions. The Partnership had no instruments designated as cash flow hedges at December 31, 2013 and 2012.

Fair Value Hedges

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

At December 31, 2013 and 2012, the Partnership had no derivative instruments that were designated as fair value hedges.

Derivatives Not Designated as Hedging Instruments

Derivative instruments not designated as hedging instruments are utilized in the Partnership's asset management activities. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized currently in earnings, unless designated as normal purchases or normal sales.

Quantitative Disclosures, Balance Sheet Presentation and Income Statement Presentation Related to Derivative Instruments

At December 31, 2013 and 2012 and for the year ended December 31, 2013, 2012 and 2011 the Partnership had no material derivative instruments to disclose.

Credit-Risk Related Contingent Features in Derivative Instruments

In the event Moody's Investors Services or Standard & Poor's Ratings Services were to lower the Partnership's or Enable Oklahoma's senior unsecured debt ratings to a below investment grade rating, the Partnership or Enable Oklahoma would have been required to post no cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position at December 31, 2013. The Partnership or Enable Oklahoma could be required to provide additional credit assurances in future dealings with third parties, which could include letters of credit or cash collateral.

(11) Related Party Transactions

The related party transactions with CenterPoint Energy, OGE Energy and their respective subsidiaries are summarized and described below. There were no material related party transactions with other affiliates.

The Partnership's revenues from affiliated companies accounted for 9%, 14% and 15% of revenues during the year ended December 31, 2013, 2012 and 2011, respectively. Amounts of revenues from affiliated companies included in the Partnership's Combined and Consolidated Statements of Income are summarized as follows:

	December 31,		
	2013	2012	2011
	(In millions)		
Gas transportation and storage - CenterPoint Energy	$ 108	$ 133	$ 140
Gas sales - CenterPoint Energy	70	—	—
Gas transportation and storage - OGE Energy(1)	32	—	—
Gas sales - OGE Energy(2)	14	—	—
Total revenues—affiliated companies	$ 224	$ 133	$ 140

(1) The Partnership has contracts with OGE Energy to transport natural gas to OGE Energy's natural gas-fired generation facilities and store natural gas that are reflected in Partnership's Combined and Consolidated Statement of Income beginning on May 1, 2013.

(2) The Partnership sells natural gas to OGE Energy's natural gas-fired generation facilities that are reflected in the Partnership's Combined and Consolidated Statement of Income beginning on May 1, 2013.

Amounts of natural gas purchased from affiliated companies included in the Partnership's Combined and Consolidated Statements of Income are summarized as follows:

	December 31,		
	2013	2012	2011
	(In millions)		
Cost of goods sold—CenterPoint Energy	$ 4	$ 1	$ 1

The Partnership recorded an expense from OGE Energy of $8 million for the period beginning May 1, 2013 and ended December 31, 2013 for electricity used to power the Partnership's electric compression assets, which is reflected in the Partnership's Combined and Consolidated Statement of Income as operation and maintenance expense beginning on May 1, 2013.

Prior to May 1, 2013, the Partnership had employees and reflected the associated benefit costs directly and not as corporate services. Under the terms of the MFA, effective May 1, 2013 the Partnership's employees were seconded by CenterPoint Energy and OGE Energy, and the Partnership began reimbursing each CenterPoint Energy and OGE Energy for all employee costs under the seconding agreements until terminated with at least 90 days' notice by CenterPoint Energy or OGE Energy, respectively, or by the Partnership. The Partnership intends to identify those seconded employees ("selected employees") to whom it will extend an employment offer during 2014. The Partnership anticipates transitioning the selected employees from CenterPoint Energy and OGE Energy to the Partnership effective January 1, 2015.

Prior to May 1, 2013, the Partnership received certain services and support functions from CenterPoint Energy described below. Under the terms of the MFA, effective May 1, 2013 the Partnership receives services and support functions from CenterPoint Energy and OGE Energy under service agreements for an initial term ending on April 30, 2016. The service agreements automatically extend year-to-year at the end of the initial term, unless terminated by the Partnership with at least 90 days' notice. Additionally, the Partnership may terminate these service agreements at any time with 180 days' notice, if approved by the Board of the General Partner. The Partnership reimburses CenterPoint Energy and OGE Energy for these services up to annual caps, initially $44 million and $30 million, respectively. The Board of Directors of the General Partner has approved 2014 annuals caps of $38 million and $28 million for CenterPoint Energy and OGE Energy, respectively.

The Partnership's operations are dependent on CenterPoint Energy's and OGE Energy's ability to perform under these service agreements, which include certain support functions for accounting, finance, investor relations, planning, legal, communications, governmental and regulatory affairs, and human resources, as well as information technology services and other shared services such as corporate security, facilities management, office support services, and purchasing and logistics. The cost of these services has been charged directly to the Partnership through negotiated usage rates, dedicated asset assignment and proportionate corporate formulas based on operating expenses, assets, gross margin, employees and a composite of assets, gross margin and employees. In some instances, OGE Energy uses the "Distrigas" method to allocate operating costs to the Partnership. The Distrigas method is a three-factor formula that uses an equal weighting of payroll, net operating revenues and gross property, plant and equipment. OGE Energy adopted the Distrigas method in January 1996 as a result of a recommendation by the Staff of the Oklahoma Corporation Commission. CenterPoint Energy uses the Composite Ratio Formula that allocates costs incurred by a service company on behalf of its affiliates to those affiliates. This three-part formula consisting of gross margin, assets, and the number of employees applied 40%, 40% and 20% respectively, attempts to weight various aspects of each of the affiliates so that a fair distribution of the overhead cost is allocated to each affiliate member. These charges are not necessarily indicative of what would have been incurred had the Partnership not been an affiliate of CenterPoint Energy or OGE Energy.

Amounts charged to the Partnership by affiliates for seconded employees and corporate services, included primarily in operating and maintenance expenses in Partnership's Combined and Consolidated Statements of Income are as follows:

	December 31,		
	2013	**2012**	**2011**
	(In millions)		
Seconded Employee Costs—CenterPoint Energy(1)	$ 92	$ —	$ —
Corporate Services—CenterPoint Energy(1)	38	39	37
Seconded Employee Costs—OGE Energy(2)	78	–	–
Corporate Services—OGE Energy(2)	18	–	–
Total corporate services and seconded employee expense	$ 226	$ 39	$ 37

(1) Beginning on May 1, 2013, CenterPoint Energy assumed all employees of Partnership and seconded such employees to the Partnership. Therefore, costs historically incurred directly by Partnership for employment services are reflected as seconded employee costs subsequent to formation on May 1, 2013.

(2) Corporate services and seconded employee expenses from OGE Energy are reflected in the Statement of Combined and Consolidated Income beginning on May 1, 2013. With respect to the annual cap of $30 million for corporate services, $28 million was incurred during the year ended December 31, 2013, including $10 million prior to the Partnership's acquisition of Enogex on May 1, 2013.

On July 1, 2009, OGE Energy and Enogex entered into hedging transactions to offset natural gas long positions at Enogex with short natural gas exposures at OGE Energy resulting from the cost of generation associated with a wholesale power sales contract. These transactions are for approximately 50,000 million British thermal unit per month from August 2009 to December 2013. These transactions are reflected in the Combined and Consolidated Statement of Income beginning on May 1, 2013.

Until May 1, 2013, the Partnership participated in a "money pool" through which it could borrow or invest with CenterPoint Energy on a short-term basis. Funding needs were aggregated and external borrowing or investing was based on the net cash position. The Partnership's money pool borrowings and investments were reflected in notes payable-affiliated companies and notes receivable-affiliated companies, respectively, in the Combined Balance Sheet as of December 31, 2012.

The notes receivable-affiliated companies as of December 31, 2012 include $434 million and $45 million investments in the money pool and other notes receivable, respectively, and bear an interest rate of 4.869% and 3.25%, respectively. Immediately prior to formation as a limited partnership on May 1, 2013, the Partnership received cash for repayment of the $434 million of investments in the money pool and received a contribution from CenterPoint Energy for the settlement of the $45 million of other notes receivable. Interest income of $9 million, $21 million, and $14 million for the year ended December 31, 2013, 2012 and 2011, respectively, is included in Interest income-affiliated companies.

The Partnership has outstanding short-term and long-term notes payable-affiliated companies to CenterPoint Energy as presented below:

	Year ended December 31,			
	2013		2012	
	Long-Term	Current	Long-Term	Current
Short-term notes payable-affiliated companies:	(In millions)			
Notes payable-affiliated companies [1]	$ —	$ —	$ —	$ 753
Long-term notes payable-affiliated companies:				
Notes payable-affiliated companies[2]	$ 363	$ —	$ 363	$ —
Notes payable-affiliated companies[3]	—	—	646	—
Total long-term notes payable—affiliated companies	$ 363	$ —	$ 1,009	$ —

(1) These notes were payable on demand to CenterPoint Energy. Substantially all of these notes represented the Partnership's money pool borrowings. At December 31, 2012, the Partnership's money pool borrowings had an interest rate of 4.869%. These notes were repaid and terminated immediately prior to formation as a limited partnership on May 1, 2013 without premium or penalty.

(2) These notes are payable to CenterPoint Energy and mature in 2017. Notes having an aggregate principal amount of approximately $273 million bear a fixed interest rate of 2.10% and notes having an aggregate principal amount of approximately $90 million bear a fixed interest rate of 2.45%.

(3) These notes were payable to CenterPoint Energy, bear a fixed interest rate of 6.30% and were scheduled to mature in 2036. These notes were repaid and terminated immediately prior to formation as a limited partnership on May 1, 2013 without premium or penalty.

Prior to repayment of the $753 million and $646 million of short-term and long-term notes payable—affiliated companies, respectively, the Partnership assumed an additional $143 million through a distribution of the Partnership. In total, the repayment of notes payable—affiliated companies immediately prior to formation as a limited partnership on May 1, 2013 was $1.54 billion.

The liabilities recognized upon acquisition of Enogex included $136 million of advances due affiliated companies, payable to OGE Energy. On May 1, 2013, these advances were repaid from proceeds under the Revolving Credit Agreement.

The Partnership recorded affiliated interest expense to CenterPoint Energy of $34 million, $85 million and $90 million during the year ended December 31, 2013, 2012 and 2011, respectively, on notes payable—affiliated companies, which is included in Interest expense on the Combined and Consolidated Statements of Income.

CenterPoint Energy has provided guarantees (Encana and Shell Guarantees) with respect to the performance of certain obligations of the Partnership under long-term gas gathering and treating agreements with an affiliate of Encana Corporation (Encana) and an affiliate of Royal Dutch Shell plc (Shell). As of December 31, 2013, CenterPoint Energy had guaranteed the Partnership's obligations up to an aggregate amount of $100 million under these agreements. Under the terms of the omnibus agreement entered into in connection with the Partnership's formation as a limited partnership on May 1, 2013, the Partnership and CenterPoint Energy have agreed to use commercially reasonable efforts and cooperate with each other to terminate the Encana and Shell Guarantees, and to release CenterPoint Energy from such guarantees by causing the Partnership or one of its subsidiaries to enter into substitute guarantees or to assume the Encana and Shell Guarantees.

(12) Commitments and Contingencies

(a) Long-Term Agreements

Long-term Gas Gathering and Treating Agreements. The Partnership has long-term agreements with Encana and Shell to provide gathering and treating services for their natural gas production from certain Haynesville Shale and Bossier Shale formations in Texas and Louisiana.

Under the long-term agreements, Encana or Shell may elect to require the Partnership to expand the capacity of its gathering systems by up to an additional 1.3 Bcf per day. The Partnership estimates that the cost to expand the capacity of its gathering systems by an additional 1.3 Bcf per day would be as much as $440 million. Encana and Shell would provide incremental volume commitments in connection with an election to expand system capacity.

Long-term Agreement with Exxon. In March 2013, Enable Bakken entered into a long-term agreement with an affiliate of Exxon-Mobil Corporation (Exxon), to provide gathering services for certain of Exxon’s crude oil production through a new crude oil gathering and transportation pipeline system in North Dakota’s liquids-rich Bakken shale. The agreement with Exxon was entered into pursuant to the open season announced by Enable Bakken in February 2013. Under the terms of the agreement, which includes volume commitments, Enable Bakken will provide service to Exxon over a gathering system to be constructed by Enable Bakken in Dunn and McKenzie counties in North Dakota with a capacity of up to 19,500 barrels per day. Certain portions of the pipeline system were placed in service in 2013 with the remaining portions to be placed in service in the third quarter of 2014. As of December 31, 2013, the Partnership estimates the remaining construction costs to be $17 million.

Operating Lease Obligations. The Partnership has operating lease obligations expiring at various dates. Future minimum payments for noncancellable operating leases are as follows:

Year ended December 31 (In millions)	2014	2015	2016	2017	2018	After 2018	Total
Noncancellable operating leases	$ 7	$ 5	$ 2	$ 1	$ —	$ —	$ 15

Total rental expense for all operating leases was $12 million, $16 million and $26 million in 2013, 2012 and 2011, respectively.

The Partnership currently occupies 134,219 square feet of office space at its executive offices under a lease that expires March 31, 2017. The lease payments are $11 million over the lease term, which began April 1, 2012. This lease has rent escalations which increase after 5 and 10 years if the lease is renewed. These lease expenses are reflected in the Statement of Combined or Consolidated Income beginning on May 1, 2013.

The Partnership currently has 23 compression service agreements, of which three agreements are on a month-to-month basis, three agreements will expire in 2014, 17 agreements will expire in 2015 and 2 agreements will expire in 2016. The Partnership also has 8 gas treating agreements, of which 6 agreements are on a month-to-month basis, one agreement will expire in 2013 and one agreement will expire in 2014. These lease expenses are reflected in the Statement of Combined or Consolidated Income beginning on May 1, 2013.

Other Purchase Obligations and Commitments. In 2004, Enable Oklahoma entered into a firm transportation service agreement with Cheyenne Plains, who operates the Cheyenne Plains Pipeline that provides firm transportation services in Wyoming, Colorado and Kansas, for 60,000 dekatherms/day of firm capacity on the pipeline. The firm transportation service agreement was for a 10-year term beginning with the in-service date of the Cheyenne Plains Pipeline in March 2005 with an annual demand fee of $7 million. Effective March 1, 2007, Enable Oklahoma and Cheyenne Plains amended the firm transportation service agreement to provide for Enable Oklahoma to turn back 20,000 dekatherms/day of its capacity beginning in January 2008 for the remainder of the term.

In 2006, Enable Oklahoma entered into a firm capacity agreement with Midcontinent Express Pipeline (MEP) for a primary term of 10 years (subject to possible extension) that gives MEP and its shippers’ access to capacity on Enable Oklahoma’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 2009, Enable Oklahoma entered into a firm transportation service agreement with MEP for 10,000 dekatherms/day of firm capacity on the pipeline. The firm transportation service agreement was for a five-year term beginning with the in-service date of the MEP pipeline in June 2009 with an annual demand fee of $2 million.

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

Year ended December 31 (In millions)	2014	2015	2016	2017	2018	Total
Other purchase obligations and commitments	$ 11	$ 4	$ 1	$ —	$ —	$ 16

(b) Legal, Regulatory and Other Matters

Regulatory Matters

MRT Rate Case. MRT, a subsidiary of the Partnership, made a rate filing with the FERC pursuant to Section 4 of the Natural Gas Act, on August 22, 2012 that became effective March 1, 2013, following a five-month suspension, in which it requested an annual cost of service of $104 million (an increase of approximately $47 million above the annual cost of service underlying the current FERC approved maximum rates for MRT's pipeline). On July 30, 2013, MRT filed with the FERC an uncontested Stipulation and Agreement and Offer of Settlement, resolving all issues in the rate case. The settlement specifies few particulars, other than setting an annual overall cost-of-service for MRT of $84 million and increasing the depreciation rates for certain asset classes. In September 2013, the FERC approved the settlement. Although the settlement became effective November 1, 2013, the settlement rates are effective as of March 1, 2013. As a result, in the fourth quarter of 2013 MRT made refunds to certain of its customers totaling approximately $6 million, which amounts had previously been reserved.

2013 Fuel Filing. On March 1, 2013, Enable Oklahoma 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, 2013 through March 31, 2014). The deadline for interventions and protests on the filing was March 18, 2013 and no protests were filed. On June 25, 2013, the FERC accepted Enable Oklahoma's proposed zonal fuel percentages.

Other Proceedings

The Partnership is involved in other legal, environmental, tax and regulatory proceedings before various courts, regulatory commissions and governmental agencies regarding matters arising in the ordinary course of business. Some of these proceedings involve substantial amounts. The Partnership regularly analyzes current information and, as necessary, provides accruals for probable liabilities on the eventual disposition of these matters. The Partnership does not expect the disposition of these matters to have a material adverse effect on its financial condition, results of operations or cash flows.

(13) Income Taxes

Prior to May 1, 2013, the Partnership was included in the consolidated income tax returns of CenterPoint Energy. The Partnership calculated its income tax provision on a separate return basis under a tax sharing agreement with CenterPoint Energy.

Upon conversion to a limited partnership on May 1, 2013, the Partnership's earnings are no longer subject to income tax (other than Texas state margin taxes) and are taxable at the individual partner level. The Partnership and its subsidiaries are pass-through entities for federal income tax purposes. See Note 1 for further discussion of the conversion to a limited partnership. For these entities, all income, expenses, gains, losses and tax credits generated flow through to their owners and, accordingly, do not result in a provision for income taxes in the financial statements, (other than Texas state margin taxes). Consequently, the Combined and Consolidated Statements of Income do not include an income tax provision for income earned on or after May 1, 2013 (other than Texas state margin taxes).

The items comprising income tax expense are as follows:

	Year Ended December 31, 2013	2012	2011
	(In millions)		
Provision (benefit) for current income taxes:			
Federal	$ 1	$ 6	$ (20)
State	1	1	7
Total Provision (benefit) current income taxes	2	7	(13)
Provision (benefit) for deferred income taxes, net:			
Federal	(1,039)	164	146
State	(155)	32	30
Total provision (benefit) for deferred income taxes, net	(1,194)	196	176
Total income tax expense (benefit)	$ (1,192)	$ 203	$ 163

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

	Year Ended December 31, 2013	2012	2011
	(In millions)		
Income before income taxes	$ 426	$ 519	$ 395
Federal statutory rate	35 %	35%	35%
Expected federal income tax expense	149	182	138
Increase in tax expense resulting from:			
State income taxes, net of federal income tax	8	21	24
Income not subject to tax	(103)	—	—
Conversion to partnership	(1,240)	—	—
Other, net	(6)	—	1
Total	(1,341)	21	25
Total income tax expense (benefit)	$ (1,192)	$ 203	$ 163
Effective tax rate	(275.9)%	39.1%	41.2%

As a result of the conversion to a partnership, CenterPoint Energy assumed all outstanding current income tax liabilities and the deferred income tax assets and liabilities were eliminated by recording a provision for income tax benefit equal to $1.24 billion. Therefore, there were no federal deferred income tax assets and liabilities balances at December 31, 2013. The components of Deferred Income Taxes as of December 31, 2013 and 2012 were as follows:

	December 31,	
	2013	2012
	(In millions)	
Deferred tax assets:		
Current:		
Deferred gas costs	$ —	$ 29
Other	—	2
Total current deferred tax assets	—	31
Non-current:		
Employee benefits	—	11
Net operating loss carryforwards	—	8
Other	—	7
Total non-current deferred tax assets	—	26
Total deferred tax assets	—	57
Deferred tax liabilities:		
Non-current:		
Depreciation	8	1,219
Other	—	79
Total non-current deferred tax liabilities	8	1,298
Accumulated deferred income taxes, net	$ 8	$ 1,241

Tax Attribute Carryforwards and Valuation Allowance. At December 31, 2012, the Partnership had approximately $5 million of federal net operating loss carryforwards which begin to expire in 2031 and $120 million of state net operating loss carryforwards which expire in various years between 2013 and 2032. At December 31, 2012 the Partnership expected to realize the benefit of its deferred tax assets before expiration and as a result there was no valuation allowance at December 31, 2012. As a result of the conversion to a partnership, the federal and state net operating losses were distributed to CenterPoint Energy as part of a deemed liquidation for tax purposes on May 1, 2013. Accordingly, there were no remaining carryforwards available to the Partnership as of December 31, 2013.

Uncertain Income Tax Positions. The following table reconciles the beginning and ending balance of the Partnership's unrecognized tax benefits:

	December 31,		
	2013	2012	2011
	(In millions)		
Balance, beginning of year	$ —	$ 3	$ 5
Tax Positions related to prior years:			
Reductions	—	(3)	(2)
Balance, end of year	$ —	$ —	$ 3

The Partnership's unrecognized tax benefits on uncertain tax positions would not affect the effective income tax rate if they were recognized. The Partnership recognizes interest and penalties as a component of income tax expense. There was no unrecognized tax benefit as of December 31, 2013 and 2012. The Partnership recognized approximately $-0- million, $1 million of income tax benefit, and less than $1 million of income tax expense related to the Partnership's interest on uncertain income tax positions during the year ended December 31, 2013, 2012 and 2011 respectively. The Partnership accrued no interest on uncertain income tax positions related to the Partnership at December 31, 2013 and 2012.

Tax Audits and Settlements. CenterPoint Energy's consolidated federal income tax returns have been audited by the IRS and settled through the 2011 tax year. CenterPoint Energy is currently under examination by the IRS for tax year 2012. The Partnership considered the effect of this examination in its accrual for settled issues and liability for uncertain income tax positions as of December 31, 2013.

(14) Reportable Business Segments

The Partnership's determination of reportable business segments considers the strategic operating units under which it manages sales, allocates resources and assesses performance of various products and services to wholesale or retail customers in differing regulatory environments. The accounting policies of the business segments are the same as those described in the summary of significant accounting described in Note 1. Some executive benefit costs of Partnership, incurred prior to May 1, 2013 have not been allocated to business segments. The Partnership uses operating income as the measure of profit or loss for its business segments.

The Partnership's assets and operations are organized into two business segments: (i) Gathering and Processing, which primarily provides natural gas and crude oil gathering, processing and fractionation services for our producer customers, and (ii) Transportation and Storage, which provides interstate and intrastate natural gas pipeline transportation and storage service to natural gas producers, utilities and industrial customers. Effective May 1, 2013, the intrastate natural gas pipeline operations acquired from Enogex were combined with the interstate pipelines in the Transportation and Storage segment and the non-rate regulated natural gas gathering, processing and treating operations acquired from Enogex were combined within the Gathering and Processing segment.

During the integration of the operations acquired from Enogex, the intrastate natural gas pipelines and non- rate regulated natural gas gathering, processing and treating operations have been identified as separate operating segments, which are aggregated with the respective interstate pipelines and legacy gathering and processing operations as the respective (1) Transportation and Storage and (2) Gathering and Processing reportable segments.

Financial data for business segments and services are as follows:

Year Ended December 31, 2013	Gathering and Processing[1]	Transportation and Storage[2]	Eliminations	Total
		(In millions)		
Operating revenues[3][4]	$ 1,740	$ 1,149	$ (400)	$ 2,489
Cost of goods sold	1,075	636	(398)	1,313
Operation and maintenance	222	209	(2)	429
Depreciation and amortization	117	95	—	212
Impairment	12	—	—	12
Taxes other than income	20	34	—	54
Operating income	$ 294	$ 175	$ —	$ 469
Total assets	$ 7,157	$ 5,717	$ (1,642)	$ 11,232
Capital expenditures	$ 431	$ 142	$ —	$ 573

Year Ended December 31, 2012	Gathering and Processing[1]	Transportation and Storage[2]	Eliminations	Total
		(In millions)		
Operating revenues[3][4]	$ 502	$ 502	$ (52)	$ 952
Cost of goods sold	124	55	(50)	129
Operation and maintenance	114	155	(2)	267
Depreciation and amortization	50	56	—	106
Taxes other than income	5	29	—	34
Operating income	$ 209	$ 207	$ —	$ 416
Total assets	$ 2,439	$ 4,052	$ (9)	$ 6,482
Capital expenditures	$ 70	$ 132	$ —	$ 202

Year Ended December 31, 2011	Gathering and Processing[1]	Transportation and Storage[2]	Eliminations	Total
		(In millions)		
Operating revenues[3][4]	$ 415	$ 553	$ (36)	$ 932
Cost of goods sold	70	65	(34)	$ 101
Operation and maintenance	111	154	(2)	$ 263
Depreciation and amortization	37	54	—	$ 91
Taxes other than income	5	32	—	$ 37
Operating income	$ 192	$ 248	$ —	$ 440
Total assets	$ 1,933	$ 3,869	$ (6)	$ 5,796
Capital expenditures	$ 248	$ 98	$ —	$ 346

(1) Gathering and processing recorded equity income of $-0-, $5 million and $10 million for the year ended December 31, 2013, 2012 and 2011, respectively, from its 50% interest in a jointly-owned gas processing plant, Waskom. These amounts are included in Equity in earnings of equity method affiliates under the Other income (expense) caption. The Partnership consolidated Waskom during the third quarter of 2012. See Note 7 for further discussion regarding Waskom.

(2) Transportation and storage recorded equity income of $15 million, $26 million and $21 million for the year ended December 31, 2013, 2012 and 2011 respectively, from its interest in SESH, a jointly-owned pipeline. These amounts are included in Equity in earnings of equity method affiliates under the Other Income (Expense) caption. Transportation and Storage's investment in SESH was $198 million, $404 million as of December 31, 2013 and 2012, respectively, and is included in Investments in equity method affiliates. The Partnership reflected a 50% interest in SESH until May 1, 2013 when the Partnership distributed a 25.05% interest in SESH to CenterPoint Energy. See Note 7 for further discussion regarding SESH.

(3) Revenues are comprised of gathering, processing, transportation and storage revenues.

(4) The Partnership had no external customers accounting for 10% or more of revenues in periods shown. See Note 11 for revenues from affiliated companies.

(15) Subsequent Events

On February 14, 2014, the Partnership distributed $114 million to the unitholders of record as of January 1, 2014.

OGE Energy Corp.

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February 25, 2014

Securities and Exchange Commission
Division of Corporation Finance
100 F Street, N.E.
Washington, D.C. 20549

Gentlemen:

On behalf of OGE Energy Corp., I am submitting to you via electronic filing, pursuant to Instruction D to Form 10-K, the Company's Form 10-K for the year ended December 31, 2013, including financial statements, financial statement schedules, exhibits and the power of attorney.

Very truly yours,

/s/ Scott Forbes

By: Scott Forbes
Controller and Chief Accounting Officer