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, 2015

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. o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See 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 30, 2015, the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of shares of common stock held by non-affiliates was $5,677,464,513 based on the number of shares held by non-affiliates (198,721,194) and the reported closing market price of the common stock on the New York Stock Exchange on such date of $28.57.

At January 29, 2016, there were 199,702,753 shares of common stock, par value $0.01 per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The Proxy Statement for the Company's 2016 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, 2015

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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
ALJ	Administrative Law Judge
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
ASU	Financial Accounting Standards Board Accounting Standards Update
AVEC	Arkansas Valley Electric Cooperative Corporation
BART	Best available retrofit technology
Bcf/d	Billion cubic feet per day
Btu	British thermal unit
CSAPR	Cross-State Air Pollution Rule
CenterPoint	CenterPoint Energy Resources Corp., wholly-owned Subsidiary of CenterPoint Energy, Inc.
CO_2	Carbon dioxide
Code	Internal Revenue Code of 1986
Company	OGE Energy Corp, collectively with its subsidiaries and Enable Midstream Partners
Dry Scrubbers	Dry flue gas desulfurization units with spray dryer absorber
ECP	Environmental Compliance Plan
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
FASB	Financial Accounting Standards Board
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
IRP	Integrated Resource Plans
LTSA	Long-Term Service Agreement
MATS	Mercury and Air Toxics Standards
MBbl/d	Thousand barrels per day
MMBtu	Million British thermal unit
MMcf/d	Million cubic feet per day
Mustang Modernization Plan	OG&E's plan to replace the soon-to-be retired Mustang steam turbines in late 2017 with 400 MW of new, efficient combustion turbines at the Mustang site in 2018 and 2019
MW	Megawatt
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NGLs	Natural gas liquids
NO_X	Nitrogen oxide
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 26.3 percent owner of Enable Midstream Partners
OSHA	Federal Occupational Safety and Health Act of 1970
Pension Plan	Qualified defined benefit retirement plan
Ppb	Parts per billion
PUD	Public Utility Division of the Oklahoma Corporation Commission
QF	Qualified cogeneration facilities
QF contracts	Contracts with QFs and small power production producers
Regional Haze	The EPA's regional haze rule
Restoration of Retirement Income Plan	Supplemental retirement plan to the Pension Plan

SESH	Southeast Supply Header, LLC
SIP	State implementation plan
SO_2	Sulfur dioxide
SPP	Southwest Power Pool
Stock Incentive Plan	2013 Stock Incentive Plan
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's 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; 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. The accounts of the Company and its wholly owned subsidiaries are included in the consolidated financial statements. All intercompany transactions and balances are eliminated in consolidation. The Company generally uses the equity method of accounting for investments where its ownership interest is between 20 percent and 50 percent and has the ability to exercise significant influence. The Company was incorporated in August 1995 in the state of Oklahoma and its principal executive offices are located at 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321; telephone 405-553-3000.

The electric utility segment generates, transmits, distributes and sells electric energy in Oklahoma and western Arkansas. Its operations are conducted through OG&E and are subject to regulation by the OCC, the APSC and the FERC. OG&E was incorporated in 1902 under the laws of the Oklahoma Territory and is a wholly owned subsidiary of the Company. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes Fort Smith, Arkansas and the surrounding communities. 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 currently represents the Company's investment in Enable through its wholly owned subsidiary OGE Holdings. 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 a crude oil gathering business in the Bakken shale formation, principally located in the Williston basin of North Dakota. Enable's natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois. For periods prior to the formation of Enable, the natural gas midstream operations segment reflected the consolidated results of Enogex Holdings.

Enable was formed effective May 1, 2013 by the Company, the ArcLight group and CenterPoint to own and operate the midstream businesses of the Company and CenterPoint. In the formation transaction, the Company and the 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's 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 management ownership. Based on the 50/50 management ownership, with neither company having control, effective May 1, 2013, the Company began accounting for its interest in Enable using the equity method of accounting.

In April 2014, Enable completed an initial public offering of 25,000,000 common units resulting in Enable becoming a publicly traded Master Limited Partnership. At December 31, 2015, the Company owned approximately 111.0 million limited partner units, or 26.3 percent, of which 68.2 million limited partner units were subordinated.

On January 22, 2016, Enable announced a quarterly dividend distribution of $0.31800 per unit on its outstanding common and subordinated units, which is unchanged from the previous quarter. Based on current commodity prices, Enable has seen changes in producer activity that have negatively impacted Enable's operations and financial position and could see additional changes in producer activity that may negatively impact Enable's operations and affect its future distribution rates. If cash distributions to Enable’s unitholders exceed $0.330625 per unit in any quarter, the general partner will receive increasing percentages, up to 50 percent, of the cash Enable distributes in excess of that amount. OGE Holdings is entitled to 60 percent of those “incentive distributions.”

Company Strategy

The Company's mission, through OG&E and its equity interest in Enable, 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 interest in a publicly traded midstream company, while providing competitive energy products and services to customers, as well as seeking growth opportunities in both businesses.

OG&E is focused on:

- Providing exceptional customer experiences by continuing to improve customer interfaces, tools, products and services that deliver high customer satisfaction and operating productivity.
- Providing safe, reliable energy to the communities and customers we serve. A particular focus is on enhancing the value of the grid by improving distribution grid reliability by reducing the frequency and duration of customer interruptions and leveraging previous grid technology investments.
- Maintaining strong regulatory and legislative relationships for the long-term benefit of our customers, investors and members.
- Continuing to grow a zero-injury culture and deliver top-quartile safety results.
- Complying with the EPA's MATS and Regional Haze requirements.
- Ensuring we have the necessary mix of generation resources to meet the long-term needs of our customers.
- Continuing focus on operational excellence and efficiencies in order to protect the customer bill.

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 for OG&E of three to five percent on a weather-normalized basis, maintaining a strong credit rating as well as targeting dividend increases of approximately 10 percent annually through 2019. The targeted annual dividend increase 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 and the composition of the Company's assets and investment opportunities. The Company also relies on cash distributions from its investment in Enable to fund its capital needs and support future dividend growth. 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 267 communities and their contiguous rural and suburban areas. 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 267 communities that OG&E serves, 241 are located in Oklahoma and 26 are in Arkansas. OG&E derived 91 percent of its total electric operating revenues in 2015 from sales in Oklahoma and the remainder from sales in Arkansas. As of December 31, 2015, OG&E no longer serves wholesale customers in either state.

OG&E's system control area peak demand in 2015 was 6,537 MWs on August 7, 2015. OG&E's load responsibility peak demand was 5,998 MWs on August 7, 2015. As reflected in the table below and in the operating statistics that follow, there were 27.2 million MWh system sales in 2015, 28.0 million MWh system sales in 2014 and 28.2 million MWh system sales in 2013. Variations in system sales for the three years are reflected in the following table:

Year ended December 31	**2015**	**2015 vs. 2014 Decrease**	2014	2014 vs. 2013 Decrease	2013
System sales - (*Millions of MWh*)	**27.2**	**(2.9)%**	28.0	(0.7)%	28.2

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 as well as from consumers choosing appliances powered by other energy sources. 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. It is possible that changes in regulatory policies or advances in technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells will reduce costs of new technology to levels that are equal to or below that of most central station electricity production. Our ability to maintain relatively low cost, efficient and reliable operations is a significant determinate of our competitiveness.

OKLAHOMA GAS AND ELECTRIC COMPANY
CERTAIN OPERATING STATISTICS

Year ended December 31	**2015**	2014	2013
ELECTRIC ENERGY *(Millions of MWh)*			
Generation (exclusive of station use)	**20.9**	22.8	24.2
Purchased	**9.2**	8.8	6.3
Total generated and purchased	**30.1**	31.6	30.5
OG&E use, free service and losses	**(1.2)**	(1.4)	(1.9)
Electric energy sold	**28.9**	30.2	28.6
ELECTRIC ENERGY SOLD *(Millions of MWh)*			
Residential	**9.2**	9.4	9.4
Commercial	**7.4**	7.2	7.1
Industrial	**3.6**	3.8	3.9
Oilfield	**3.4**	3.4	3.4
Public authorities and street light	**3.1**	3.2	3.2
Sales for resale	**0.5**	1.0	1.2
System sales	**27.2**	28.0	28.2
Off-system sales	**1.7**	2.2	0.4
Total sales	**28.9**	30.2	28.6
ELECTRIC OPERATING REVENUES *(In millions)*			
Residential	**$ 896.5**	$ 925.5	$ 901.4
Commercial	**535.0**	583.3	554.2
Industrial	**190.6**	224.5	220.6
Oilfield	**162.8**	188.3	176.4
Public authorities and street light	**194.2**	220.3	214.3
Sales for resale	**21.7**	52.9	59.4
System sales revenues	**2,000.8**	2,194.8	2,126.3
Off-system sales revenues	**48.6**	94.1	14.7
Other	**147.5**	164.2	121.2
Total operating revenues	**$ 2,196.9**	$ 2,453.1	$ 2,262.2
ACTUAL NUMBER OF ELECTRIC CUSTOMERS *(At end of period)*			
Residential	**705,294**	697,048	690,390
Commercial	**93,401**	91,966	90,279
Industrial	**2,872**	2,901	2,921
Oilfield	**6,328**	6,460	6,431
Public authorities and street light	**16,880**	16,581	16,877
Sales for resale	**1**	26	42
Total	**824,776**	814,982	806,940
AVERAGE RESIDENTIAL CUSTOMER SALES			
Average annual revenue	**$ 1,278.51**	$ 1,334.05	$ 1,312.39
Average annual use (kilowatt-hour)	**13,062**	13,540	13,718
Average price per kilowatt-hour (cents)	**9.79**	9.85	9.57

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 2015, 86 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight percent to the APSC and six percent to the FERC.

The OCC issued an order in 1996 authorizing OG&E to reorganize into a subsidiary of the Company. The order required that, among other things, (i) the Company permit the OCC access to the books and records of the Company and its affiliates relating to transactions with OG&E, (ii) the Company employ accounting and other procedures and controls to protect against subsidization of non-utility activities by OG&E's customers and (iii) the Company refrain from pledging OG&E assets or income for affiliate transactions. In addition, the Energy Policy Act of 2005 enacted the Public Utility Holding Company Act of 2005, which in turn granted to the FERC access to the books and records of the Company and its affiliates as the FERC deems relevant to costs incurred by OG&E or necessary or appropriate for the protection of utility customers with respect to the FERC jurisdictional rates.

Completed Regulatory Matters

Fuel Adjustment Clause Review for Calendar Year 2013

The OCC routinely reviews the costs recovered from customers through OG&E's fuel adjustment clause. On July 31, 2014, the OCC Staff filed an application to review OG&E's fuel adjustment clause for calendar year 2013, including the prudence of OG&E's electric generation, purchased power and fuel procurement costs. On May 21, 2015, the ALJ recommended that the OCC find that OG&E's 2013 electric generation, purchased power and fuel procurement processes and costs were prudent, accurate and properly applied to customer billing statements. OG&E received an order to that effect from the OCC on June 17, 2015.

Oklahoma Demand Program Rider

On January 6, 2016, the OCC approved OG&E's 2016 through 2018 demand portfolio programs. The order stipulates recovery of program costs, lost revenues and incentives resulting from those programs, through the Demand Program Rider.

Pending Regulatory Matters

Set forth below is a list of various proceedings pending before state or federal regulatory agencies. Unless stated otherwise, OG&E cannot predict when the regulatory agency will act or what action the regulatory agency will take. OG&E's financial results are dependent in part on timely and adequate decisions by the regulatory agencies that set OG&E's rates.

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 along with the corresponding process for allocating the costs of such expansions. Order No. 1000 requires individual regions to determine whether a previously-approved project is subject to reevaluation and is therefore governed by the new rule.

Order No. 1000 directs public utility transmission providers to remove from the FERC-jurisdictional tariff and agreement 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 or to 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's pre-Order No. 1000 tariff included 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 previous transmission projects in Oklahoma. On May 29, 2013, the Governor of Oklahoma 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 kV that interconnect to those incumbent owners' existing facilities.

The SPP has submitted compliance filings implementing Order No. 1000's requirements. In response, the FERC issued an order on the SPP filings that required the SPP to remove certain right of first refusal language from the SPP Tariff and the SPP Membership Agreement. On December 15, 2014, OG&E filed an appeal in the District of Columbia Court of Appeals challenging the FERC's order requiring the removal of the right of first refusal language from the SPP Membership Agreement. The court has not yet acted on OG&E's appeal.

Oklahoma Demand Program Rider Review - SmartHours Program

In July 2012, OG&E filed an application with the OCC to recover certain costs associated with Demand Programs through the Demand Program Rider, including the lost revenues associated with the SmartHours program. The SmartHours program is designed to incentivize participating customers to reduce on-peak usage or shift usage to off-peak hours during the months of May through October, by offering lower rates to those customers in the off-peak hours of those months. Lost revenues are created by the difference in the standard rates and the lower incentivized rates. Non-SmartHours program customers benefit from the reduction of on-peak usage by SmartHours customers by the reduction of more costly on-peak generation and the delay in adding new on-peak generation.

In December 2012, the OCC issued an order approving the recovery of costs associated with the Demand Programs, including the lost revenues associated with the SmartHours program, subject to the Oklahoma PUD staff review.

In March 2014, the Oklahoma PUD staff began their review of the Demand Program cost, including the lost revenues associated with the SmartHours program. In November 2014, OG&E believed that it had reached an agreement with the Oklahoma PUD staff on the methodology to be used to calculate lost revenues associated with the SmartHours program and the amount of lost revenue for 2013, which totaled $10.1 million. The agreement also included utilizing the same methodology for calculating lost revenues for 2014, which resulted in lost revenues for 2014 of $11.6 million.

In January 2015, OG&E implemented rates that began recovering the 2013 lost revenues, in accordance with the agreement that it believed had been reached with the Oklahoma PUD staff.

In April 2015, the Oklahoma PUD staff filed an application, seeking an order from the OCC, for determining the proper methodology for calculating lost revenues pursuant to OG&E’s Demand Program Rider, primarily affecting the SmartHours program lost revenues. In the application, the Oklahoma PUD staff recommends the OCC approve the Oklahoma PUD staff methodology for calculating lost revenues associated with the SmartHours program, which differs from the methodology that OG&E believes it agreed upon and which would result in recovery of lost revenue for 2013 of $4.9 million, a reduction of $5.2 million from the amount recorded by OG&E for 2013.

OG&E believes the methodology agreed to in November 2014 is consistent with the 2012 OCC order and it is probable that OG&E will recover the $10.1 million of lost revenues associated with 2013, the $11.6 million associated with 2014 and the $14.9 million associated with 2015. A hearing was held on June 30, 2015 and July 1, 2015. OG&E is unable to predict when it will receive a ruling from the OCC.

Environmental Compliance Plan

On August 6, 2014, OG&E filed an application with the OCC for approval of its plan to comply with the EPA’s MATS and Regional Haze FIP while serving the best long-term interests of customers in light of future environmental uncertainties. The application sought approval of the ECP and for a recovery mechanism for the associated costs. The ECP includes installing dry scrubbers at Sooner Units 1 and 2 and the conversion of Muskogee Units 4 and 5 to natural gas. The application also asks the OCC to predetermine the prudence of its Mustang Modernization Plan which calls for replacing OG&E's soon-to-be retired Mustang steam turbines in late 2017 with 400 MWs of new, efficient combustion turbines at the Mustang site in 2018 and 2019 and approval for a recovery mechanism for the associated costs. OG&E estimates the total capital cost associated with its environmental compliance plan to be approximately $1.1 billion. The OCC hearing on OG&E's application before an ALJ began on March 3, 2015 and concluded on April 8, 2015. Multiple parties advocating a variety of positions intervened in the proceeding.

On June 8, 2015, the ALJ issued his report on OG&E's application. While the ALJ in his report agreed that the installation of dry scrubbers at Sooner Units 1 and 2 and the conversion of Muskogee Units 4 and 5 to natural gas pursuant to OG&E’s ECP is the best approach, the ALJ's report included several recommendations. OG&E filed exceptions to the ALJ's report and on July 21, 2015, Commissioner Bob Anthony issued his deliberation statement that was consistent with many parts of the ALJ's report, including the ALJ’s support of OG&E’s ECP, the ALJ’s recommendation to pre-approve certain estimated costs of the environmental recovery plan, and the ALJ’s recommendation to defer all other cost recovery issues until the next general rate case.

On December 2, 2015, OG&E received an order from the OCC denying, by a two to one vote, its plan to comply with the environmental mandates of the Federal Clean Air Act, Regional Haze and MATS. The OCC also denied OG&E's request for pre-approval of its Mustang Modernization Plan, revised depreciation rates for both the retirement of the Mustang units and the replacement combustion turbines and pre-approval of early retirement and replacement of generating units at its Mustang site, including cost recovery through a rider.

On December 11, 2015, OG&E filed a motion requesting modification of the OCC order for the purposes of approving only the ECP. OG&E did not seek modification to any other provisions of the OCC order, including cost recovery. OG&E also agreed that it would not implement a rider for recovery of the costs of the ECP until and unless authorized by the OCC in a subsequent proceeding. On December 23, 2015, the OCC rejected, by a two to one vote, a proposal by Commissioner Dana Murphy to grant OG&E's December 11, 2015 motion.

On February 12, 2016, OG&E filed an application requesting the OCC to issue an order approving the installation of dry scrubbers at the Sooner facility, on or before May 2, 2016. The application states that if the application is not approved by May 2, 2016, OG&E will decide at that time whether to cancel the dry scrubber equipment and installation contracts and make plans to convert the Sooner coal units to natural gas. As of December 31, 2015, OG&E had incurred $94.8 million of construction work in progress on the dry scrubbers. OG&E estimates another $35.0 million of in-process expenditures will be incurred prior to May 1, 2016. Additionally, if the request is not approved, OG&E expects to seek recovery in subsequent proceedings for the expenditures incurred for the dry scrubber project and reasonable stranded costs associated with the discontinuance of the Sooner coal units.

Fuel Adjustment Clause Review for Calendar Year 2014

On July 28, 2015, the OCC staff filed an application to review OG&E's fuel adjustment clause for calendar year 2014, 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 September 2, 2015. A hearing is scheduled to be held on April 7, 2016.

Integrated Resource Plans

In August 2015, OG&E initiated the process to update its IRP pursuant to the OCC rules. After engaging interested stakeholders in August and September, OG&E finalized the 2015 IRP and submitted it to the OCC on October 1, 2015. The 2015 IRP updated certain assumptions contained in the IRP submitted in 2014, but did not make any material changes to the ECP and other parts of the action plan contained in the IRP submitted in 2014.

Oklahoma Rate Case Filing

On December 18, 2015, OG&E filed a general rate case with the OCC requesting a rate increase of $92.5 million and a 10.25 percent return on equity based on a June 30, 2015 test year. OG&E primarily seeks to recover $1.6 billion of electric infrastructure additions since its last general rate case in Oklahoma, the impact of the expiration of OG&E's wholesale contracts and increased operating costs such as vegetation management.

Arkansas Rate Case Filing

OG&E intends to file a general rate case with the APSC by August 15, 2016.

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 incurred 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 incurred costs and obligations as regulatory assets or liabilities if, based on regulatory orders or other available evidence, it is probable that the costs or obligations will be included in amounts allowable for recovery or refund in future rates.

At December 31, 2015 and 2014, OG&E had regulatory assets of $448.7 million and $508.6 million, respectively, and regulatory liabilities of $341.4 million and $287.4 million, respectively. See Note 1 of Notes to Consolidated Financial Statements for a further discussion.

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

Rate Structures

Oklahoma

OG&E's standard tariff rates include a cost-of-service component (including an authorized return on capital) plus a fuel adjustment clause mechanism that allows OG&E to pass through to customers 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. 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 the Public Schools-Demand and Public Schools Non-Demand rate classes 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.

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 and purchased power. 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 2015, 49.0 percent of the OG&E-generated energy was produced by coal-fired units, 44.0 percent by natural gas-fired units and seven percent by wind-powered units. Of OG&E's 6,771 total MWs of generation capability reflected in the table under

Item 2. Properties, 3,770 MWs, or 55.7 percent, are from natural gas generation, 2,552 MWs, or 37.7 percent, are from coal generation and 449 MWs, or 6.6 percent, are from wind generation. Over the last five years, the weighted average cost of fuel used, by type, was as follows:

Year ended December 31 *(In cents/Kilowatt-Hour)*	**2015**	2014	2013	2012	2011
Natural gas	**2.529**	4.506	3.905	2.930	4.328
Coal	**2.187**	2.152	2.273	2.310	2.064
Weighted average	**2.196**	2.752	2.784	2.437	2.897

The decrease in the weighted average cost of fuel in 2015 as compared to 2014 was primarily due to lower natural gas prices. The decrease in the weighted average cost of fuel in 2014 as compared to 2013 was primarily due to less natural gas used, offset by higher natural gas prices. 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. These fuel costs are recovered through OG&E's fuel adjustment clauses that are approved by the OCC, the APSC and the FERC.

OG&E began participating in the SPP Integrated Marketplace effective March 1, 2014. The SPP Integrated Marketplace replaced the SPP Energy Imbalance Services market. As part of the Integrated Marketplace, the SPP assumed balancing authority responsibilities for its market participants. The SPP Integrated Marketplace functions as a centralized dispatch, where market participants, including OG&E, submit offers to sell power to the SPP from their resources and bid to purchase power from the SPP for their customers. The SPP Integrated Marketplace is intended to allow the SPP to optimize supply offers and demand bids based upon reliability and economic considerations, and determine which generating units will run at any given time for maximum cost-effectiveness. As a result, OG&E's generating units produce output that is different from OG&E's customer load requirements. Net fuel and purchased power costs are recovered through fuel adjustment clauses.

Coal

OG&E's coal-fired units, with an aggregate capability of 2,552 MWs, are designed to burn low sulfur western sub-bituminous coal. The combination of all coal has a weighted average sulfur content of 0.23 percent. Based on the average sulfur content and EPA-certified data, OG&E's coal units have an approximate emission rate of 0.5 lbs of SO_2 per MMBtu.

OG&E has acquired 100 percent of its forecasted annual coal usage via existing inventory and purchase contracts that expire in December 2016 and December 2017. In 2015, OG&E purchased 7.7 million tons of coal from various Wyoming suppliers. 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

As a participant in the SPP Integrated Marketplace, OG&E now purchases a relatively small percentage of its natural gas supply through long-term agreements. Alternatively, OG&E relies on a combination of call natural gas agreements, whereby OG&E has the right but not the obligation to purchase a defined quantity of natural gas, combined with day and intra-day purchases to meet the demands of the SPP Integrated Marketplace.

Wind

OG&E's current wind power portfolio includes the following, in addition to the 120 MW Centennial, 101 MW OU Spirit and 228 MW Crossroads wind farms owned by OG&E: (i) 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, (ii) access to up to 152 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 2031, (iii) 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 2031 and (iv) 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, the 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 is a large-scale, growth-oriented publicly traded Delaware limited partnership formed to own, operate and develop strategically located natural gas and crude oil infrastructure assets. Enable serves current and emerging production areas in the United States, including several unconventional shale resource plays and local and regional end-user markets in the United States. Enable's assets and operations are organized into two reportable segments: (i) Gathering and Processing, which primarily provides natural gas gathering, processing and fractionation services and crude oil gathering for its producer customers and (ii) Transportation and Storage, which provides interstate and intrastate natural gas pipeline transportation and storage services primarily to natural gas producers, utilities and industrial customers.

Enable's natural gas gathering and processing assets are located in five states and serve natural gas production from shale developments in the Anadarko, Arkoma and Ark-La-Tex basins. Enable also owns a crude oil gathering business in North Dakota's Bakken Shale formation of the Williston Basin that commenced initial operations in November 2013. Enable's natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois.

Enable was formed on May 1, 2013, to own and operate the midstream businesses of OGE Energy and CenterPoint. As of December 31, 2015, Enable's portfolio of energy infrastructure assets included approximately 12,400 miles of gathering pipelines, 13 major processing plants with approximately 2.3 Bcf/d of processing capacity, approximately 7,900 miles of interstate pipelines (including SESH), approximately 2,200 miles of intrastate pipelines and eight natural gas storage facilities providing approximately 85.0 Bcf of storage capacity.

For the year ended December 31, 2015, approximately 81 percent of Enable's gross margin was generated from contracts that are fee-based, and approximately 56 percent of its gross margin was attributable to fees associated with firm contracts or contracts with minimum volume commitment features.

The following table shows the components of Enable's gross margin for the year ended December 31, 2015.

	Fee-Based			
	Demand/Commitment/Guaranteed Return	Volume Dependent	Commodity-Based	Total
Year Ended December 31, 2015				
Gathering and Processing Segment	34%	38%	28%	100%
Transportation and Storage Segment	86%	8%	6%	100%
Partnership Weighted Average	56%	25%	19%	100%

Gathering and Processing

Enable owns and operates approximately 12,400 miles of natural gas gathering pipelines in the Anadarko, Arkoma and Ark-La-Tex basins with approximately 976,000 horsepower of compression and 13 natural gas processing plants with approximately 2.3 Bcf/d of processing capacity and 2.3 Bcf/d of treating capacity as of December 31, 2015. Enable provides gathering, compression, treating, dehydration, processing and NGL fractionation for producers who are active in the areas in which it operates. For the year ended December 31, 2015, its assets gathered an average of approximately 3.14 TBtu/d of natural gas. For the year ended December 31, 2015, Enable processed approximately 1.78 TBtu/d of natural gas and produced approximately 73.55 MBbl/d of NGLs.

As of December 31, 2015, Enable's processing infrastructure consisted of 13 plants located in the Anadarko, Arkoma and Ark-La-Tex basins. The assets serving the Anadarko basin consist of ten processing plants, eight of which are interconnected through its super-header system, and are configured to facilitate the flow of natural gas from western Oklahoma and the Wheeler County area in the Texas Panhandle to the Bradley, Cox City, Thomas, McClure, Calumet, Clinton, South Canadian and Wheeler processing plants. Enable is also constructing two additional cryogenic processing facilities to connect to its super-header system in Grady County, Oklahoma and Garvin County, Oklahoma, which are expected to add 400 MMcf/d of natural gas processing capacity. The first of the two new plants (the Bradley 2 Plant) is a 200 MMcf/d plant which is expected to be completed in the second quarter of 2016. The second plant (the Wildhorse Plant) is a 200 MMcf/d plant that is expected to be completed in late 2017. Enable's super-header system is intended to allow it to optimize the economics of its natural gas processing and to improve system utilization and reliability. The Wetumka Plant in the Arkoma basin serves the rich gas western portion of the area. The Sligo and Waskom plants in the Ark-La-Tex basin serve the Haynesville, Cotton Valley and Lower Bossier plays.

The following table sets forth certain information regarding Enable's gathering and processing assets as of or for the year ended December 31, 2015:

Asset/Basin	Length (miles)	Compression (Horsepower)	Average Gathering Volume (TBtu/d)	Number of Processing Plants	Processing Capacity (MMcf/d)	NGLs Produced (MBbl/d)	Gross Acreage Dedications (in millions)
Anadarko Basin	7,700	690,600	1.59	10	1,645	58.50	4.6
Arkoma Basin	3,000	135,800	0.67	1	60	4.98	1.4
Ark-La-Tex Basin(A)	1,700	150,000	0.88	2	545	10.07	0.7
Total	12,400	976,400	3.14	13	2,250	73.55	6.7

(A) 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.

For the year ended December 31, 2015, Enable generated 72.0 percent of its gathering and processing gross margin from gathering and processing fees. The remaining 28.0 percent of gross margin for the year ended December 31, 2015 came from commodities, including natural gas, natural gas liquids, and condensate received under percent-of-proceeds, percent-of-liquids and keep-whole arrangements. For the year ended December 31, 2015, contracts generating 34.0 percent of gathering and processing gross margin had minimum volume commitments and guaranteed return features with remaining terms ranging from two to 12 years. Under a minimum volume commitment, a customer commits to ship a minimum volume of natural gas over a period of time on Enable's gathering system, or, in lieu of shipping such volumes, to pay as if that minimum amount had been shipped.

As of December 31, 2015, Enable's gathering agreements had acreage dedications with original terms ranging up to 15 years, which generally require that production by customers within the acreage dedication be delivered to Enable's gathering system. As of December 31, 2015, Enable's natural gas gathering agreements had acreage dedications of 6.7 million gross acres with a volume-weighted average remaining term of approximately seven years. In addition, as of December 31, 2015, Enable had minimum volume commitments in lean natural gas developments of 2.1 Bcf/d with a weighted average remaining term of over six years.

Transportation and Storage

Enable provides fee-based interstate and intrastate transportation and storage services across nine states. Enable owns and operates approximately 7,900 miles (including SESH) of interstate transportation pipelines with average firm contracted capacity of 7.19 Bcf/d (excluding SESH), for the year ended December 31, 2015. In addition, Enable owns and operates approximately 2,200 miles of intrastate transportation pipelines with average aggregate throughput of 1.84 TBtu/d for the year ended December 31, 2015. Enable also owns and operates eight natural gas storage facilities in Oklahoma, Louisiana and Illinois with approximately 85.0 Bcf of aggregate storage capacity.

The following table sets forth certain information regarding Enable's transportation and storage assets as of December 31, 2015:

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[(A)]	7,900	8.4	Bcf/d	7.19	3.1 [(B)]	86%	3.3
Intrastate Transportation	2,200	2.1	Bcf/d[(C)]	—	1.8	—%	5.5
Storage	—	85	Bcf	64.69	—	76%	3.5

(A) Except with respect to length, this information does not include amounts for SESH. SESH is a non-consolidated entity in which Enable owns a 50.0 percent ownership interest.

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

(C) This represents the maximum single day receipts on the intrastate systems. Enable's Oklahoma intrastate pipeline system is a web-like configuration with multi-directional flow capabilities between numerous receipt and delivery points, which limits the ability to determine an overall system capacity. During the year ended December 31, 2015, the peak daily throughput was 2.1 TBtu or, on a volumetric basis, 2.1 Bcf/d.

ENVIRONMENTAL MATTERS

General

The activities of the Company are subject to numerous stringent and complex Federal, state and local laws and regulations governing environmental protection. These laws and regulations can change, restrict or otherwise impact OG&E's business activities in many ways including the handling or disposal of waste material, future construction activities to avoid or mitigate harm to threatened or endangered species and requiring the installation and operation of emissions 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. OG&E believes that its operations are in substantial compliance with current Federal, state and local environmental standards.

The trend in environmental regulation, however, is to place more restrictions and limitations on activities that may affect the environment. 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 2016 will be $195.9 million, of which $178.3 million is for capital expenditures. It is estimated that OG&E's total expenditures to comply with environmental laws, regulations and requirements for 2017 will be approximately $166.7 million of which $148.7 million is for capital expenditures. The amounts for OG&E above include capital expenditures for low NO_X burners and dry scrubbers. 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 2016 through 2020 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. Estimated capital expenditures for Enable are not included in the table below.

(In millions)	2016	2017	2018	2019	2020
OG&E Base Transmission	$ 50	$ 30	$ 30	$ 30	$ 30
OG&E Base Distribution	190	175	175	175	175
OG&E Base Generation	60	75	75	75	75
OG&E Other	40	25	25	25	25
Total Base Transmission, Distribution, Generation and Other	340	305	305	305	305
OG&E Known and Committed Projects:					
Transmission Projects:					
Other Regionally Allocated Projects (A)	50	25	20	20	20
Large SPP Integrated Transmission Projects (B) (C)	20	150	20	—	—
Total Transmission Projects	70	175	40	20	20
Other Projects:					
Environmental - low NO_X burners (D)	20	10	—	—	—
Environmental - natural gas conversion (D)	—	—	40	35	—
Environmental - dry scrubbers (D)	150	140	90	20	—
Combustion turbines - Mustang	180	100	50	5	—
Total Other Projects	350	250	180	60	—
Total Known and Committed Projects	420	425	220	80	20
Total	$ 760	$ 730	$ 525	$ 385	$ 325

(A) Typically 100kV to 299kV projects. Approximately 30 percent of revenue requirement allocated to SPP members other than OG&E.
(B) Typically 300kV and above projects. Approximately 85 percent of revenue requirement allocated to SPP members other than OG&E.

(C)

Project Type	Project Description	Estimated Cost (In millions)	Projected In-Service Date
Integrated Transmission Project	30 miles of transmission line from OG&E's Gracemont substation to an AEP companion transmission line to its Elk City substation. Approximately $5.0 million of the estimated cost has been spent prior to 2016.	$45	Late 2017
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. Approximately $55.0 million of the estimated cost associated with the Mathewson to Cimarron line and substations will go into service in 2016; $35.0 million has been spent prior to 2016.	$190	Mid 2018

(D) Represent capital costs associated with OG&E's ECP to comply with the EPA's MATS and Regional Haze rules. More detailed discussion regarding Regional Haze and OG&E's ECP can be found in Note 15 of Notes to Financial Statements under "Environmental Compliance Plan" in Item 8 of Part II of this Form 10-K, and under "Environmental Laws and Regulations" within "Management's Discussion and Analysis of Financial Condition and Results of Operations" under Part II, Item 7 of this Form 10-K. On February 12, 2016, OG&E filed an application requesting the OCC to issue an order approving the installation of dry scrubbers at the Sooner facility, on or before May 2, 2016. The application states that if the application is not approved by May 2, 2016, OG&E will decide at that time whether to cancel the dry scrubber equipment and installation contracts and make plans to convert the Sooner coal units to natural gas. As of December 31, 2015, OG&E had incurred $94.8 million of construction work in progress on the dry scrubbers. OG&E estimates another $35.0 million of in-process expenditures will be incurred prior to May 1, 2016. Additionally, if the request is not approved, OG&E expects to seek recovery in subsequent proceedings for the expenditures incurred for the dry scrubber project and reasonable stranded costs associated with the discontinuance of the Sooner coal units. The capital costs in the table above do not reflect any actions or costs that may be incurred (including the conversion of the Sooner coal units) if the May 2, 2016 application is not approved.

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 2015 and 2014, OGE Energy did not make any contributions to its Pension Plan. The Company has not determined whether it will need to make any contributions to the Pension Plan in 2016. 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 September 2015 board meeting, the Board of Directors approved management's recommendation of a 10 percent increase in the quarterly dividend rate to $0.27500 per share from $0.25000 per share effective in October 2015. 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 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 agreement. 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. As of December 31, 2015, the Company had no short-term debt compared to a balance of $98.0 million at December 31, 2014. The average balance of short-term debt in 2015 was $75.2 million at a weighted-average interest rate of 0.46 percent. The maximum month-end balance of short-term debt in 2015 was $180.0 million. At December 31, 2015, the Company had $1,148.1 million of net available liquidity under its revolving credit agreements. OG&E has the necessary regulatory approvals to incur up to $800.0 million in short-term borrowings at any one time for a two-year period beginning January 1, 2015 and ending December 31, 2016. At December 31, 2015, the Company had $75.2 million in cash and cash equivalents. See Note 11 of Notes to Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

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 contained an option, which could be exercised up to two times, to extend the term for an additional year. In the third quarter of 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 from December 13, 2016 to December 13, 2017. In the second quarter of 2014, the Company and OG&E utilized their second extension to extend the maturity of their respective credit facility from December 13, 2017 to December 13, 2018. As of December 31, 2015, commitments of approximately $16.3 million and $8.7 million of the Company's and OG&E's credit facilities, respectively, however, were not extended and, unless the non-extending lender is replaced in accordance with the terms of the credit facility, such commitments will expire December 13, 2017.

Common Stock

The Company does not expect to issue any common stock in 2016 from its Automatic Dividend Reinvestment and Stock Purchase Plan. See Note 9 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, the amount of distributions the Company received from Enable were $139.3 million and $143.7 million during the years ended December 31, 2015 and 2014.

EMPLOYEES

The Company had 2,586 employees at December 31, 2015 of which 166 are seconded to Enable.

EXECUTIVE OFFICERS

The following persons were Executive Officers of the Registrant as of February 26, 2016:

Name	Age	Title
Sean Trauschke	48	Chairman of the Board, President and Chief Executive Officer - OGE Energy Corp.
E. Keith Mitchell	53	Chief Operating Officer - OG&E
Stephen E. Merrill	51	Chief Financial Officer - OGE Energy Corp.
Scott Forbes	58	Controller and Chief Accounting Officer - OGE Energy Corp.
Patricia D. Horn	57	Vice President - Governance and Corporate Secretary - OGE Energy Corp.
Jean C. Leger, Jr.	57	Vice President - Utility Operations - OG&E
Kenneth Grant	51	Vice President- Sales and Marketing - OG&E
Cristina F. McQuistion	51	Vice President - Chief Information Officer and Utility Strategy - OG&E
Jerry A. Peace	53	Vice President- Integrated Resource Planning and Development - OG&E
Paul L. Renfrow	59	Vice President - Public Affairs and Corporate Administration - OGE Energy Corp.
Charles B. Walworth	41	Treasurer - OGE Energy Corp.

No family relationship exists between any of the Executive Officers of the Registrant. Messrs. Trauschke, Merrill, Forbes, 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 Shareholders, currently scheduled for May 19, 2016.

Mr. Trauschke is a member 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	
Sean Trauschke	2015 - Present:	Chairman of the Board, President and Chief Executive Officer of OGE Energy Corp.
	2014 - 2015:	President of OGE Energy Corp.
	2011 - 2014:	Vice President and Chief Financial Officer of OGE Energy Corp.
E. Keith Mitchell	2015 - Present	Chief Operating Officer of OG&E
	2013 - 2015:	Executive Vice President and Chief Operating Officer of Enable Midstream Partners, LP
	2011 - 2013:	President and Chief Operating Officer of Enogex Holdings; President of Enogex LLC
	2011:	Senior Vice President and Chief Operating Officer of Enogex LLC
Stephen E. Merrill	2014 - Present:	Chief Financial Officer of OGE Energy Corp.
	2013 - 2014:	Executive Vice President of Finance and Chief Administrative Officer of Enable Midstream Partners, LP
	2011 - 2013:	Chief Operating Officer of Enogex LLC
	2011:	Vice President - Human Resources of OGE Energy Corp.
Scott Forbes	2011 - Present:	Controller and Chief Accounting Officer of OGE Energy Corp.
Patricia D. Horn	2014 - Present:	Vice President - Governance and Corporate Secretary of OGE Energy Corp.
	2012 - 2014:	Vice President - Governance, Environmental and Corporate Secretary of OGE Energy Corp.
	2011 - 2012:	Vice President - Governance, Environmental, Health & Safety; Corporate Secretary of OGE Energy Corp.
Jean C. Leger, Jr.	2011 - Present:	Vice President - Utility Operations of OG&E
Kenneth R. Grant	2015 - Present:	VP Sales and Marketing - OG&E
	2015:	VP Marketing and Product Development - OG&E
	2013 - 2015:	Managing Director Tech Solutions & Ops - OG&E
	2011 - 2013:	Managing Director Customer Solutions - OG&E
	2011:	Managing Director Smart Grid Program - 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
Jerry A. Peace	2014 - Present:	Vice President - Integrated Resource Planning and Development - OG&E
	2011 - 2014:	Chief Risk Officer of OGE Energy Corp.
Paul L. Renfrow	2014 - Present:	Vice President - Public Affairs and Corporate Administration of OGE Energy Corp.
	2012 - 2014:	Vice President - Public Affairs, Human Resources and Health & Safety of OGE Energy Corp.
	2011 - 2012:	Vice President - Public Affairs and Human Resources of OGE Energy Corp.
Charles B. Walworth	2014 - Present:	Treasurer of OGE Energy Corp.
	2012 - 2014:	Assistant Treasurer of OGE Energy Corp.
	2011 - 2012:	Senior Manager 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 "Investors," "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 in a timely manner 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 a timely manner. Any failure to obtain utility commission approval to increase rates to fully recover costs, or a delay in the receipt of such approval, could have an adverse impact on OG&E's results of operations.

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 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. 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.

OG&E operates in Oklahoma and western Arkansas and is subject to rate regulation by the OCC and the APSC, in addition to FERC regulation of its transmission activities and any wholesale sales. 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" and in "Pending Regulatory Matters", OG&E is required to comply with the EPA's FIP by January 4, 2019 and is currently reviewing its alternatives to comply with the EPA's Regional Haze requirements, in light of the OCC's denial of the ECP in December 2015.

In response to recent regulatory and judicial decisions and international accords, emissions of greenhouse gases including, most significantly, CO_2 could be restricted in the future as a result of Federal or state legal requirements or litigation relating to greenhouse gas emissions. Additionally, international treaties or protocols could result in future additional reductions in the United States. In October 2015, EPA issued standards for states to implement to control greenhouse gas emissions from existing electric generating units with the initial compliance period beginning in 2022 and a final compliance deadline in 2030. The standards are being challenged by 27 states and a variety of industry participants. In February 2016, the U.S. Supreme Court entered an order staying the implementation of these EPA standards. The stay will remain in place until the U.S. Supreme Court either denies a petition for certiorari following the U.S. Court of Appeals' decision on the substantive challenges to the standards, if one is submitted, or until the U.S. Supreme Court enters judgment following grant of a petition for certiorari. The effect is to delay the EPA's deadlines until the challenges have been fully litigated and the U.S. Supreme Court has ruled. If the standards survive judicial review and are implemented as written, they 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. Significant uncertainties also remain with regards to potential implementation in Oklahoma (and the federal plan that would be imposed by EPA for states that do not submit approvable plans), including whether states would elect an emissions standards approach versus a state measures approach, whether and what type of emissions trading would be allowed, and available cost mitigation options. Due to the pending litigation and the uncertainties in the state approaches, the ultimate timing and impact of these standards on our operations cannot be determined with certainty at this time. 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. Whereas the EPA has finalized new standards for the reduction of CO_2 from electric generating units, due to the regulatory process, the ultimate timing and impact of these standards on our operations cannot be determined with certainty at this time.

There is growing effort to initiate nuisance claims against power generators. The impact of these efforts on OG&E cannot be determined with certainty as this time.

There is inherent risk of the incurrence of environmental costs and liabilities in our operations and historical industry operations 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 be no assurance as to the effectiveness of any such mitigation efforts, particularly with respect to previously incurred costs and commitments.

As discussed in Item 1. Business, Item 7. Management's Discussion and Analysis and Note 15. Rate Matters and Regulation, in December 2015, the OCC denied OG&E's ECP. OG&E is reviewing its options to meet the EPA's Regional Haze requirements. OG&E has not determined whether it will continue or abandon the construction on the dry scrubbers at Sooner Units 1 and 2. As of December 31, 2015, OG&E had incurred $94.8 million of construction work in progress on the dry scrubbers. As a result of the OCC's denial of the ECP, if OG&E completes the construction of the scrubbers, it may not be allowed to recover some or all of the construction costs, and it may not be allowed to earn a return on the investment associated with the scrubbers at Sooner Units 1 and 2.

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. On March 1, 2014, the SPP implemented and the FERC approved regional day ahead and real-time markets for energy and operating reserves, as well as associated transmission congestion rights. Collectively the three markets operate together under the global name, SPP Integrated Marketplace. OG&E represents owned and contracted generation assets and customer load in the SPP Integrated Marketplace for the sole benefit of its customers. OG&E has not participated in the SPP Integrated Marketplace for any speculative trading activities. OG&E records the SPP Integrated Marketplace transactions as sales or purchases with results reported as Operating Revenues or Cost of Goods Sold in its Consolidated Financial Statements. OG&E's revenues, expenses, assets and liabilities may be adversely affected by changes in the organization, operation and regulation of the SPP Integrated Marketplace by the FERC or the SPP.

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

We have been and will continue to be affected by competitive changes to the utility and energy industries. Significant changes 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 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 certifications 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 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 such as a severe storm or 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 purchase power 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, tornadoes, floods, earthquakes or other similar occurrences.

Changes in technology and regulatory policies may cause our generating facilities to be less competitive.

OG&E primarily generates electricity at large central facilities. This method typically results in economies of scale and lower costs than newer technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells. It is possible that advances in technologies or changes in regulatory policies will reduce costs of new technology to levels that are equal to or below that of most central station electricity production, which could have a material adverse effect on our results of operations.

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 increase the pressure on Federal, state and local governments to raise additional funds by increasing corporate tax rates and/or delaying, reducing or eliminating tax credits, grants or other incentives that could have a material adverse impact on our results of operations and cash flows.

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 physical impacts or increased rates caused by the inclusion of additional regulatory imposed costs, CO_2 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 due to a 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 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. Our generation and transmission systems are part of an interconnected system. Therefore, a disruption caused by the impact of a cyber security incident of the regional electric transmission grid, natural gas pipeline infrastructure or other fuel sources of our third party service providers' operations, could also negatively impact our business. If the technology systems were to fail or be breached and not recovered in a timely manner, 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 effect of cyber security attacks on our systems, which could adversely impact our operations.

We maintain property and casualty insurance that may cover certain resultant physical damage or third-party injuries caused by potential cyber events. However, damage and claims arising from such incidents may exceed the amount of any insurance available and other damage and claims arising from such incidents may not be covered at all. For these reasons, a significant cyber incident could reduce future net income and cash flows and impact financial condition.

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, earthquakes 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, wind storms, earthquakes and prolonged droughts 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. Additionally, if climate change exacerbates physical changes in weather, operations may be impacted as discussed above.

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 cash flow.

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, 2015, we expect to make future contributions to maintain required funding levels. It has been our practice 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, 36 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, 2015, the Company and its subsidiary had outstanding indebtedness and other liabilities of $6.3 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 shareholders.

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 corporation 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, 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 who 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

OGE Energy does not control Enable and therefore is not able to cause or prevent certain actions by Enable.

Enable has its own governing board, therefore, OGE Energy is not able to exercise control over Enable. Accordingly, OGE Energy is unable to cause or prevent certain actions by Enable.

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

- 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;
- the amount of cash reserves established by Enable GP, LLC; and
- other business risks affecting its cash levels.

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, 2015, approximately 81 percent of its gross margin was generated from contracts that are fee-based and approximately 56 percent of its gross margin was attributable to fees associated with firm contracts or contracts with minimum volume commitment features. As these and other contracts expire, Enable may have to negotiate extensions or renewals with existing suppliers and customers or enter into new contracts with other suppliers and customers. 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 terms that are favorable to Enable, 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, Laclede Group, American Electric Power Company, Inc., XTO Energy, Inc. and OGE Energy.

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 combined and consolidated financial position, results of operations and its 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 other than Enable. 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 in lieu of using Enable. 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.

The amount of cash Enable has available for distribution to holders of its common and subordinated units depends primarily on its cash flow rather than on its profitability, which may prevent Enable from making distributions, even during periods in which Enable records net income.

The amount of cash Enable has available for distribution depends primarily upon its cash flows and not solely on profitability, which will be affected by non-cash items. As a result, Enable may make cash distributions during periods when it records losses for financial accounting purposes and may not make cash distributions during periods when it records net earnings for financial accounting purposes.

Enable is expected to pay a specified minimum quarterly distribution on its outstanding units to the extent it has sufficient cash from operations after establishment of cash reserves and payment of fees and expenses, including payments to its general partner and its affiliates. The principal difference between Enable's common units and subordinated units is that in any quarter during the applicable subordination period, holders of the subordinated units are not entitled to receive any distribution until the common units have received the minimum quarterly distribution plus any arrearages in the payment of the minimum quarterly distribution on common units from prior quarters. If Enable does not pay distributions on its subordinated units, its subordinated units will not accrue arrearages for those unpaid distributions.

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 could range from approximately $105.0 million to $125.0 million for the year ending December 31, 2016, not including opportunities currently under evaluation which could add up to an additional $375.0 million of expansion capital expenditures. For example, Enable is currently constructing two cryogenic processing facilities that it plans to connect to its super-header system in Grady County, Oklahoma, which are expected to add 400 MMcf/d of natural gas processing capacity. The first of the two new plants (the Grady County Plant) is expected to be completed in the first quarter of 2016. The second plant (the Wildhorse Plant) is a 200 MMcf/d plant that is expected to be completed in the second half of 2017. Enable also plans to construct natural gas gathering and compression infrastructure to support producer activity in its growth areas.

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 not receive any material increases in revenues or cash flows 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 Enable relies on estimates of future production 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, and it may not be able to capitalize on attractive expansion opportunities. Additionally, it may become more expensive to obtain new rights-of-way or to renew existing rights-of-way. If the cost of renewing or obtaining new rights-of-way increases, 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's results of operations and its ability to make cash distributions.

Enable's results of operations and 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.

Enable's keep-whole natural gas processing arrangements, which accounted for 5 percent of its natural gas processed volumes in 2015, expose them to fluctuations in the pricing spreads between NGL prices and natural gas prices. Under these arrangements, the processor processes raw natural gas to extract NGLs and pays to the producer the natural gas equivalent Btu value of raw natural gas received from the producer in the form of either processed natural gas or its cash equivalent. The processor is generally entitled to retain the processed NGLs and to sell them for its own account. Accordingly, the processor’s margin is a function of the difference between the value of the NGLs produced and the cost of the processed natural gas used to replace the natural gas equivalent Btu value of those NGLs. Therefore, if natural gas prices increase and NGL prices do not increase by a corresponding amount, the processor has to replace the Btu of natural gas at higher prices and processing margins are negatively affected.

Enable's percent-of-proceeds and percent-of-liquids natural gas processing agreements accounted for 47 percent of its natural gas processed volumes in 2015. Under these arrangements, the processor generally gathers raw natural gas from producers at the wellhead, transports the natural gas through its gathering system, processes the natural gas and sells the processed natural gas and/or NGLs at prices based on published index prices. The price paid to producers is based on an agreed percentage of the actual proceeds of the sale of processed natural gas, NGLs or both, or the expected proceeds based on an index price. Enable refers to contracts in which the processor shares in specified percentages of the proceeds from the sale of natural gas and NGLs as “percent-of-proceeds” arrangements, and contracts in which the processor receives proceeds from the sale of a percentage of the NGLs or the NGLs themselves as compensation for processing services as “percent-of-liquids” arrangements. These arrangements expose Enable to risks associated with the price of natural gas and NGLs.

At any given time, Enable's overall portfolio of processing contracts may reflect a net short position in natural gas (meaning that it is a net buyer of natural gas) and a net long position in NGLs (meaning that it is 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's exposure to credit risks of their customers, and any material nonpayment or nonperformance by their key customers could adversely affect their cash flow and results of operations.

Some of Enable's customers may experience financial problems that could have a significant effect on its customers creditworthiness. Severe financial problems encountered by its customers could limit Enable's ability to collect amounts owed to it, or to enforce performance of obligations under contractual arrangements. In addition, many of Enable's customers finance their activities through cash flow from operations, the incurrence of debt or the issuance of equity. The combination of reduction of cash flow resulting from declines in commodity prices, a reduction in borrowing bases under reserve-based credit facilities and the lack of availability of debt or equity financing may result in a significant reduction of its customers’ liquidity and limit its customers ability to make payments or perform on obligations to Enable. Furthermore, some of Enable's customers may be highly leveraged and subject to their own operating and regulatory risks, which increases the risk that they may default on their obligations to Enable. Financial problems experienced by its customers could result in the impairment of its assets, reduction of its operating cash flows and may also reduce or curtail its customers' future use of its products and services, which could reduce revenues.

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, 2015, approximately 60 percent of Enable's contracted transportation firm capacity and 44 percent 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 to Enable for any reason, Enable's results of operations and 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 affiliates of Spectra Energy Partners, LP, 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. If these parties do not satisfy their obligations under these arrangements, Enable's business may be adversely affected.

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 obligations, leaving Enable liable for the liabilities created as a result of those unpaid obligations;
- possible inability 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.

Under certain circumstances, affiliates of Spectra Energy Partners, LP will have the right to purchase an ownership interest in SESH at fair market value.

Enable owns a 50 percent ownership interest in SESH. The remaining 50 percent ownership interests are held by affiliates of Spectra Energy Partners, LP

CenterPoint owns a 55.4 percent limited partner interest in Enable and a 40 percent economic interest in Enable GP, LLC. Pursuant to the terms of the limited liability company agreement of SESH, as amended (the SESH Agreement), if, at any time, CenterPoint has a right to receive less than 50 percent of Enable's distributions through its limited partner interest in Enable and its economic interest in the general partner, or does not have the ability to exercise certain control rights, affiliates of Spectra Energy Partners, LP could have the right to purchase Enable's interest in SESH at fair market value. Under the master formation agreement, Enable is entitled to receive the cash consideration related to any exercise of these rights by Spectra Energy Partners, LP or its affiliates.

An impairment of goodwill, long-lived assets, including intangible assets, and equity method investments could reduce Enable's earnings.

In connection with acquisitions, Enable may record goodwill and identifiable intangible assets. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. GAAP requires testing goodwill and intangible assets with indefinite useful lives for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets, including intangible assets with finite useful lives, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. For the investments Enable accounts for under the equity method, the impairment test considers whether the fair value of the equity investment as a whole, not the underlying net assets, has declined and whether that decline is other than temporary. If Enable determines that an impairment is indicated, it would be required to take an immediate non-cash charge to earnings with a correlative effect on equity and balance sheet leverage as measured by debt to total capitalization. Enable recorded impairments to goodwill of $1,087 million during the year ended December 31, 2015. Although as a result of these impairments Enable had no goodwill recorded as of December 31, 2015, it could experience future events that result in impairments if goodwill is recorded as a result of future acquisitions. Such goodwill impairments could have a significant negative impact on Enable's future operating results and could have an adverse impact on its ability to satisfy the financial ratios or other covenants under its existing or future debt agreements.

Enable's 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 results of operations or ability to make cash distributions to us.

Enable's 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, earthquakes 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. Enable currently has general liability and property insurance in place to cover certain of its facilities in amounts that it considers appropriate. Such policies are subject to certain limits and deductibles. 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.

The use of derivative contracts by Enable and its subsidiaries in the normal course of business could result in financial losses that could negatively impact its results of operations and its ability to make cash distributions to unitholders.

Enable and its subsidiaries periodically use derivative instruments, such as swaps, options, futures and forwards, to manage its commodity and financial market risks. Enable and its subsidiaries could recognize financial losses as a result of volatility in the market values of these contracts, or should a counterparty fail to perform. In the absence of actively quoted market prices and pricing information from external sources, the valuation of these financial instruments can involve management’s judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

Failure to attract and retain an appropriately qualified workforce could adversely impact Enable's results of operations.

Enable transitioned seconded employees from CenterPoint and OGE Energy to the Partnership effective January 1, 2015, except for those employees who are participants under OGE Energy's defined benefit and retiree medical plans, who will remain seconded to the Partnership, subject to certain termination rights of the Partnership and OGE Energy. Employees of OGE Energy that Enable determines to hire are under no obligation to accept Enable's offer of employment on the terms Enable provides, or at all.

Enable's business is dependent on its ability to recruit, retain and motivate employees. Certain circumstances, such as an aging workforce without appropriate replacements, a mismatch of existing skill sets to future needs, competition for skilled labor or the unavailability of contract resources may lead to operating challenges such as a lack of resources, loss of knowledge or a lengthy time period associated with skill development. Enable's costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect Enable's ability to manage and operate our business. If Enable is unable to successfully attract and retain an appropriately qualified workforce, its results of operations could be negatively affected.

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 operating subsidiaries' cash distribution policy will significantly impair its operating subsidiaries' ability to grow. In addition, because it and its operating subsidiaries distribute all available cash, its operating subsidiaries' 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 available cash that Enable has 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 growth strategy includes, in part, the ability to make acquisitions that result in an increase in its cash generated from operations. 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 adversely affected.

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, 2015, Enable had approximately $2.7 billion of long-term debt outstanding, excluding the premiums on senior notes. Enable has $363.0 million of long-term notes payable - affiliated companies due to CenterPoint. Enable also has a $1.8 billion revolving credit facility for working capital, capital expenditures and other partnership purposes, including acquisitions, of which $1.2 billion was available as of December 31, 2015. As of January 31, 2016, $232.0 million was outstanding under its commercial paper program. Enable 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 operating subsidiaries' current or future indebtedness, it and its subsidiaries 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 to Enable 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.

Affiliates of Enable's general partner, including CenterPoint Energy and the Company, may compete with Enable, and neither the general partner nor its affiliates have any obligation to present business opportunities to Enable.

Under Enable's omnibus agreement, CenterPoint Energy, the Company and their affiliates have agreed to hold or otherwise conduct all of their respective midstream operations located within the United States through Enable. This requirement will cease to apply to both CenterPoint Energy and the Company as soon as either CenterPoint Energy or the Company ceases to hold any interest in Enable's general partner or at least 20 percent of its common units. In addition, if CenterPoint Energy or the Company acquires any assets or equity of any person engaged in midstream operations with a value in excess of $50.0 million (or $100.0 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 to Enable such assets or equity for such value. If Enable does not purchase such assets, the acquiring party will be free to retain and operate such midstream assets, so long as the value of the assets does not reach certain thresholds.

As a result, under the circumstances described above, CenterPoint Energy and the Company have the ability to construct or acquire assets that directly compete with Enable's assets. Pursuant to the terms of Enable's partnership agreement, the doctrine of corporate opportunity, or any analogous doctrine, does not apply to Enable's general partner or any of its affiliates, including its executive officers and directors and CenterPoint Energy and the Company. Any such person or entity that becomes aware of a potential transaction, agreement, arrangement or other matter that may be an opportunity for Enable will not have any duty to communicate or offer such opportunity to Enable. Any such person or entity will not be liable to Enable or to any limited partner for breach of any fiduciary duty or other duty by reason of the fact that such person or entity pursues or acquires such opportunity for itself, directs such opportunity to another person or entity or does not communicate such opportunity or information to Enable. This may create actual and potential conflicts of interest between Enable and affiliates of its general partner and result in less than favorable treatment of Enable and its common unitholders.

If Enable fails to maintain an effective system of internal controls, then it may not be able to accurately report financial results or prevent fraud. As a result, current and potential unitholders could lose confidence in its financial reporting, which would harm Enable's business and the trading price of its common units.

Effective internal controls are necessary for Enable to provide reliable financial reports, prevent fraud and operate successfully as a public company. If its efforts to maintain internal controls are not successful, it will be unable to maintain adequate controls over its financial processes and reporting in the future and its operating results could be harmed or fail to meet its reporting obligations. Ineffective internal controls also could cause investors to lose confidence in its reported financial information, which would likely have a negative effect on the trading price of Enable's common units.

Cyber-attacks, acts of terrorism or other disruptions could adversely impact Enable's results of operations and its ability to make cash distributions to unitholders.

Enable is subject to cyber-security risks related to breaches in the systems and technology that it uses (i) to manage its operations and other business processes and (ii) to protect sensitive information maintained in the normal course of its businesses. The gathering, processing and transportation of natural gas from its gathering, processing and pipeline facilities are dependent on communications among its facilities and with third-party systems that may be delivering natural gas into or receiving natural gas and other products from its facilities. Disruption of those communications, whether caused by physical disruption such as storms or other natural phenomena, by failure of equipment or technology, or by manmade events, such as cyber-attacks or acts of terrorism, may disrupt its ability to deliver natural gas and control these assets. Cyber-attacks could also result in the loss of confidential or proprietary data or security breaches of other information technology systems that could disrupt its operations and critical business functions, adversely affect its reputation, and subject Enable to possible legal claims and liability. Enable is not fully insured against all cyber-security risks any of which could have a material adverse effect on its results of operations and its ability to make cash distributions to unitholders. In addition, its natural gas pipeline systems may be targets of terrorist activities that could disrupt its ability to conduct its business and have a material adverse effect on its results of operations and its ability to make cash distributions to unitholders. It is possible that any of these occurrences, or a combination of them, could have a material adverse effect on its business, financial condition and results of operations.

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. In addition, certain federal agencies have proposed additional laws and regulations to more closely regulate the hydraulic fracturing process. For example, in January 2015, the EPA indicated its intention to propose more stringent rules regulating methane and volatile organic compound emissions from hydraulic fracturing and other well completion activity. Congress from time to time has considered the adoption of legislation to provide for federal regulation of hydraulic fracturing under the Safe Drinking Water Act and to require disclosure of the chemicals used in the hydraulic fracturing process. Some states have adopted, and other states are considering adopting, legal requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular, in some cases banning hydraulic fracturing. For example, in Texas, the City of Denton recently enacted a local ordinance that would restrict hydraulic fracturing activities. 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.

In addition, certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The U.S. EPA, has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. A draft final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources is expected to be available for public comment and peer review by March 2015. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. Other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act or other regulatory mechanisms.

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. At the federal level, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, require the monitoring and reporting of greenhouse gas emissions from specified onshore and offshore oil and natural gas production sources in the United States on an annual basis, which include certain of Enable's operations. Additional EPA rules, such as the updates to the oil and gas new source performance standard requirements proposed in September 2015, could affect Enable's ability to obtain air permits for new or modified facilities or require its operations to incur additional expenses to control air emissions by installing emissions control technologies and adhering to a variety of work practice and other requirements. These requirements could increase the costs of development and production, reducing the profits available to Enable and potentially impair its operator’s ability to economically develop its properties.

In addition, the U.S. Congress has in the past and may in the future consider legislation to reduce emissions of greenhouse gases, and there has been a wide-ranging policy debate, both nationally and internationally, regarding the impact of these gases and possible means for their regulation. Efforts have been made and continue to be made in the international community toward the adoption of international treaties or protocols that would address global climate change issues. In 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement will be open for signing on April 22, 2016 and will require countries to review and “represent a progression” in their intended nationally determined contributions, which set greenhouse gas emission ("GHG") reduction goals, every five years beginning in 2020. A number of state and regional efforts have also emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. Any such future laws and regulations imposing reporting obligations on, or limiting emissions of, GHGs could require Enable to incur costs to reduce emissions of GHGs. Substantial limitations on GHG emissions could also adversely affect demand for oil and natural gas. Depending on the particular program, Enable could in the future be required to purchase and surrender emission allowances or otherwise undertake measures to reduce greenhouse gas emissions. Any additional costs or operating restrictions associated with new legislation or regulations regarding greenhouse gas emissions could have a material adverse effect on our operating results and cash flows, in addition to the demand for its services.

Increased regulatory-imposed costs may increase the cost of consuming, and thereby reduce demand for, the products that Enable gathers, treats and transports. 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.

Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have a material adverse effect on Enable's operations.

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 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 natural gas interstate pipelines are regulated by FERC under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005, Generally, FERC’s authority over interstate natural gas transportation extends to:

- rates, operating terms, conditions of service and service contracts;
- certification and construction of new facilities;
- extension or abandonment of services and facilities or expansion of existing facilities;
- maintenance of accounts and records;
- acquisition and disposition of facilities;
- initiation and discontinuation of services;
- depreciation and amortization policies;
- conduct and relationship with certain affiliates;
- market manipulation in connection with interstate sales, purchases or natural gas transportation; and
- various other matters.

FERC’s jurisdiction extends to the certification and construction of interstate transportation and storage facilities, including, but not limited to expansions, lateral and other facilities and abandonment of facilities and services. Prior to commencing construction of significant new interstate transportation and storage facilities, an interstate pipeline must obtain a certificate authorizing the construction, or an order amending its existing certificate, from FERC. Certain minor expansions are authorized by blanket certificates that FERC has issued by rule. Typically, a significant expansion project requires review by a number of governmental agencies, including state and local agencies, whose cooperation is important in completing the regulatory process on schedule. Any failure by an agency to issue sufficient authorizations or permits in a timely manner for one or more of these projects may mean that we will not be able to pursue these projects or that they will be constructed in a manner or with capital requirements that we did not anticipate. Enable's inability to obtain sufficient permits and authorizations in a timely manner could materially and negatively impact the additional revenues expected from these projects.

FERC conducts audits to verify compliance with FERC’s regulations and the terms of its orders, including whether the websites of interstate pipelines accurately provide information on the operations and availability of services. FERC’s regulations require uniform terms and conditions for service, as set forth in agreements for transportation and storage services executed between interstate pipelines and their customers. These service agreements are required to conform, in all material respects, with the standard form of service agreements set forth in the pipeline’s FERC-approved tariff. Non-conforming agreements must be filed with, and accepted by, the FERC. In the event that FERC finds that an agreement, in whole or part, is materially non-conforming, it could reject the agreement or require us to seek modification, or alternatively require us to modify our tariff so that the non-conforming provisions are generally available to all customers.

The rates, terms and conditions for transporting natural gas in interstate commerce on certain of our intrastate pipelines and for services offered at certain of Enable's storage facilities are subject to the jurisdiction of FERC under Section 311 of the Natural Gas Policy Act. Rates to provide such interstate transportation service must be “fair and equitable” under the Natural Gas Policy Act and are subject to review, refund with interest if found not to be fair and equitable, and approval by FERC at least once every five years.

Enable's crude oil gathering pipelines are subject to common carrier regulation by FERC under the Interstate Commerce Act. The Interstate Commerce Act requires that Enable maintain tariffs on file with FERC setting forth the rates Enable charges for providing transportation services, as well as the rules and regulations governing such services. The ICA requires, among other things, that Enable's rates must be “just and reasonable” and that Enable provide service in a manner that is nondiscriminatory. Shippers on Enable's crude oil gathering pipelines may protest its tariff filings, file complaints against its existing rates, or FERC can investigate Enable's rates on its own initiative. In the event that FERC finds that Enable's existing or proposed rates are unjust and unreasonable, it could deny requested rate increases or could order Enable to reduce its rates and could require the payment of reparations to complaining shippers for up to two years prior to the complaint.

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 FERC under the Natural Gas Act ("NGA"), 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 Natural Gas Policy Act ("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 the NGA or NGPA 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 are exempt and are not subject to these requirements, there is potential for Enable to incur significant costs and liabilities relating to the implementation of preventive and mitigating measures as well as any necessary repairs and remediation of their non-exempt pipelines. This work is part of its normal integrity management program and it does not expect to incur any extraordinary costs during 2016 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.

The adoption of financial reform legislation by the United States Congress could adversely affect Enable's ability to use derivative instruments to hedge risks associated with its business.

At times, Enable may hedge all or a portion of its commodity risk and its interest rate risk. The United States Congress adopted comprehensive financial reform legislation that changed federal oversight and regulation of the derivatives markets and entities, including businesses like Enable, that participate in those markets. The legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, was signed into law by the President on July 21, 2010, and requires the Commodity Futures Trading Commission and the SEC to promulgate rules and regulations implementing the legislation. In its rulemaking under the Dodd-Frank Act, the Commodity Futures Trading Commission adopted regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents, but these rules were successfully challenged in federal district court by the Securities Industry Financial Markets Association and the International Swaps and Derivatives Association and largely vacated by the court. The Commodity Futures Trading Commission appealed this ruling, but subsequently withdrew its appeal. In December 2013, the Commodity Futures Trading Commission published a Notice of Proposed Rulemaking designed to implement new position limits regulation. The ultimate form and timing of the implementation of the regulatory regime affecting commodity derivatives remains uncertain. However, reporting obligations for transactions involving non-financial swap counterparties such as Enable began on July 1, 2013 with regard to interest rate swaps and August 19, 2013 with regard to other commodity swaps such as natural gas swap products.

Under final rules adopted by the Commodity Futures Trading Commission, Enable believes its hedging transactions will qualify for the non-financial, commercial end-user exception, which exempts derivatives intended to hedge or mitigate commercial risk from the mandatory swap clearing requirement, where the counterparty such as Enable has a required identification number, is not a financial entity as defined by the regulations, and meets a minimum asset test. The Dodd-Frank Act may also require Enable to comply with margin requirements in connection with its hedging activities, although the application of those provisions to Enable is uncertain at this time. The Dodd-Frank Act may also require the counterparties to its derivative instruments to spin off some of their hedging activities to a separate entity, which may not be as creditworthy as the current counterparty.

The Dodd-Frank Act and related regulations could significantly increase the cost of derivatives contracts for Enable's industry (including requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks Enable encounters, reduce its ability to monetize or restructure its existing derivatives contracts, and increase its exposure to less creditworthy counterparties, particularly if Enable is unable to utilize the commercial end user exception with respect to certain of its hedging transactions. If Enable reduces its use of hedging as a result of the legislation and regulations, its results of operations may become more volatile and its cash flows may be less predictable, which could adversely affect its ability to plan for and fund capital expenditures and fund unitholder distributions. Finally, the legislation was intended, in part, to reduce the volatility of crude oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to crude oil and natural gas. Enable's revenues could therefore be adversely affected if a consequence of the legislation and regulations is to lower commodity prices. Any of these consequences could adversely affect its results of operations and its ability to make cash distributions to unitholders.

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 6,771 MWs at December 31, 2015. 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	2015 Capacity Factor (A)	Unit Capability (MW)	Station Capability (MW)
Seminole	1	1971	Steam-Turbine	Gas	10.0%	475	
	2	1973	Steam-Turbine	Gas	9.8%	481	
	3	1975	Steam-Turbine	Gas/Oil	15.7%	482	1,438
Muskogee	4	1977	Steam-Turbine	Coal	5.4%	487	
	5	1978	Steam-Turbine	Coal	50.0%	502	
	6	1984	Steam-Turbine	Coal	44.7%	521	1,510
Sooner	1	1979	Steam-Turbine	Coal	63.7%	521	
	2	1980	Steam-Turbine	Coal	57.3%	521	1,042
Horseshoe Lake	6	1958	Steam-Turbine	Gas/Oil	6.7%	168	
	7	1963	Combined Cycle	Gas/Oil	4.3%	221	
	8	1969	Steam-Turbine	Gas	5.2%	410	
	9	2000	Combustion-Turbine	Gas	11.6%	46	
	10	2000	Combustion-Turbine	Gas	11.3%	46	891
Redbud (B)	1	2003	Combined Cycle	Gas	66.7%	158	
	2	2003	Combined Cycle	Gas	70.1%	155	
	3	2003	Combined Cycle	Gas	71.0%	156	
	4	2003	Combined Cycle	Gas	72.7%	153	622
Mustang	3	1955	Steam-Turbine	Gas	2.3%	121	
	4	1959	Steam-Turbine	Gas	3.4%	259	
	5A	1971	Combustion-Turbine	Gas/Jet Fuel	0.5%	26	
	5B	1971	Combustion-Turbine	Gas/Jet Fuel	0.5%	33	439
McClain (C)	1	2001	Combined Cycle	Gas	84.7%	380	380
Total Generating Capability (all stations, excluding wind stations)							6,322

Station	Year Installed	Location	Number of Units	Fuel Capability	2015 Capacity Factor (A)	Unit Capability (MW)	Station Capability (MW)
Crossroads	2011	Canton, OK	98	Wind	40.3%	2.3	228
Centennial	2007	Laverne, OK	80	Wind	30.3%	1.5	120
OU Spirit	2009	Woodward, OK	44	Wind	34.3%	2.3	101
Total Generating Capability (wind stations)							449

(A) 2015 Capacity Factor = 2015 Net Actual Generation / (2015 Net Maximum Capacity (Nameplate Rating in MWs) x Period Hours (8,760 Hours))
(B) Represents OG&E's 51 percent ownership interest in the Redbud Plant.
(C) Represents OG&E's 77 percent ownership interest in the McClain Plant.

In 2015, OG&E retired the GT unit located at the Seminole station and units 1 and 2 located at the Mustang station.

At December 31, 2015, OG&E's transmission system included: (i) 52 substations with a total capacity of 13.3 million kV-amps and 4,889 structure miles of lines in Oklahoma and (ii) seven substations with a total capacity of 2.5 million kV-amps and 277 structure miles of lines in Arkansas. OG&E's distribution system included: (i) 346 substations with a total capacity of 9.7 million kV-amps, 29,255 structure miles of overhead lines, 2,539 miles of underground conduit and 10,730 miles of underground conductors in Oklahoma and (ii) 31 substations with a total capacity of 1 million kV-amps, 2,782 structure miles of overhead lines, 254 miles of underground conduit and 692 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, 2015, the Company's gross property, plant and equipment (excluding construction work in progress) additions were $2.0 billion and gross retirements were $294.0 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 19.3 percent of gross property, plant and equipment (excluding construction work in progress) at December 31, 2015.

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 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, 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 sought a judgment of infringement, unspecified damages, a permanent injunction, costs and attorney 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. 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. 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. On January 4, 2016, United States District Court Judge Robin J. Cauthron ordered, with prejudice, that all claims by TransData against OG&E be dismissed thus resolving all claims pending against OG&E in this matter. The Company now considers this case closed.

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." The following table gives information with respect to price ranges, as reported in *The Wall Street Journal* as New York Stock Exchange Composite Transactions, and dividends paid for the periods shown.

		Price	
2016	Dividend Paid	High	Low
First Quarter (through February 19)	$ 0.2750	$ 27.81	$ 23.37
2015			
First Quarter	$ 0.2500	$ 36.48	$ 30.82
Second Quarter	0.2500	33.21	28.28
Third Quarter	0.2500	31.52	26.44
Fourth Quarter	0.2750	29.40	24.15
2014			
First Quarter	$ 0.2250	$ 37.29	$ 32.91
Second Quarter	0.2250	39.10	34.93
Third Quarter	0.2250	39.28	34.88
Fourth Quarter	0.2500	37.90	32.85

At the Company's September 2015 board meeting, the Board of Directors approved management's recommendation of a 10 percent increase in the quarterly dividend rate to $0.2750 per share from $0.2500 per share effective in October 2015.

The number of record holders of the Company's Common Stock at December 31, 2015, was 16,214. The book value of the Company's Common Stock at December 31, 2015 was $16.65 per share.

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. Enable's partnership agreement requires that it distribute all "available cash", as defined as cash on hand at the end of a quarter after the payment of expenses and the establishment of cash reserves, and cash on hand resulting from working capital borrowings made after the end of the quarter.

Pursuant to the leverage restriction in the Company’s revolving credit agreement, the Company must maintain a percentage of debt to total capitalization at a level that does not exceed 65 percent. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization, which results in the restriction of approximately $387.7 million of the Company’s retained earnings from being paid out in dividends. Accordingly, approximately $1.9 billion of the Company’s retained earnings as of December 31, 2015 are unrestricted for the payment of dividends.

Pursuant to the Federal Power Act, OG&E is restricted from paying dividends from its capital accounts. Dividends are paid from retained earnings. Pursuant to the leverage restriction in OG&E’s revolving credit agreement, OG&E must also maintain a percentage of debt to total capitalization at a level that does not exceed 65 percent. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization, which results in the restriction of approximately $411.0 million of OG&E's retained earnings from being paid out in dividends. Accordingly, approximately $1.7 billion of OG&E's retained earnings as of December 31, 2015 are unrestricted for the payment of dividends.

Issuer Purchases of Equity Securities

The following table contains information about the Company's purchases of its common stock during the fourth quarter of 2015.

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
10/01/15 - 10/31/15	—		$ —	N/A	N/A
11/01/15 - 11/30/15	—		$ —	N/A	N/A
12/01/15 - 12/31/15	181	(A)	$ 25.52	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	2015	2014	2013	2012	2011
SELECTED FINANCIAL DATA					
(In millions, except per share data)					
Results of Operations Data (A):					
Operating revenues	**$ 2,196.9**	$ 2,453.1	$ 2,867.7	$ 3,671.2	$ 3,915.9
Cost of sales	**865.0**	1,106.6	1,428.9	1,918.7	2,277.9
Operating expenses	**850.7**	809.7	885.3	1,075.6	991.3
Operating income	**481.2**	536.8	553.5	676.9	646.7
Equity in earnings of unconsolidated affiliates	**15.5**	172.6	101.9	—	—
Allowance for equity funds used during construction	**8.3**	4.2	6.6	6.2	20.4
Other income	**27.0**	17.8	31.8	17.6	19.8
Other expense	**14.3**	14.4	22.2	16.5	21.7
Interest expense	**149.0**	148.4	147.5	164.1	140.9
Income tax expense	**97.4**	172.8	130.3	135.1	160.7
Net income	**271.3**	395.8	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	**$ 271.3**	$ 395.8	$ 387.6	$ 355.0	$ 342.9
Basic earnings per average common share attributable to OGE Energy common shareholders	**$ 1.36**	$ 1.99	$ 1.96	$ 1.80	$ 1.75
Diluted earnings per average common share attributable to OGE Energy common shareholders	**$ 1.36**	$ 1.98	$ 1.94	$ 1.79	$ 1.73
Dividends declared per common share	**$ 1.05000**	$ 0.95000	$ 0.85125	$ 0.79750	$ 0.75875
Balance Sheet Data (at period end):					
Property, plant and equipment, net	**$ 7,322.4**	$ 6,979.9	$ 6,672.8	$ 8,344.8	$ 7,474.0
Total assets	**$ 9,597.4**	$ 9,527.8	$ 9,134.7	$ 9,922.2	$ 8,906.0
Long-term debt	**$ 2,755.6**	$ 2,755.3	$ 2,400.1	$ 2,848.6	$ 2,737.1
Total stockholders' equity	**$ 3,326.0**	$ 3,244.4	$ 3,037.1	$ 3,072.4	$ 2,819.3
Capitalization Ratios (B)					
Stockholders' equity	**54.7%**	54.1%	55.9%	51.9%	50.7%
Long-term debt	**45.3%**	45.9%	44.1%	48.1%	49.3%
Ratio of Earnings to Fixed Charges (C)					
Ratio of earnings to fixed charges	**4.12**	4.49	3.98	3.94	4.12

(A) In May 2013, Enable was formed to own and operate the midstream business of OGE Energy and CenterPoint. OGE Energy accounts for its interest in Enable using the equity method of accounting subsequent to the formation of Enable. Prior to May 1, 2013, OGE Energy consolidated the results of Enogex.

(B) 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)].

(C) For purposes of computing the ratio of earnings to fixed charges, (i) earnings consist of income from continuing operations before income taxes and equity in earnings of unconsolidated affiliates, plus distributed equity 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. The accounts of the Company and its wholly owned subsidiaries are included in the consolidated financial statements. All intercompany transactions and balances are eliminated in consolidation. The Company generally uses the equity method of accounting for investments where its ownership interest is between 20 percent and 50 percent and has the ability to exercise significant influence.

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, and is a wholly owned subsidiary of the Company. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes Fort Smith, Arkansas and the surrounding communities. 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 currently represents the Company's investment in Enable through its wholly owned subsidiary OGE Holdings. 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 a crude oil gathering business in the Bakken shale formation, principally located in the Williston basin of North Dakota. Enable's natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois. For periods prior to the formation of Enable, the natural gas midstream operations segment reflected the consolidated results of Enogex Holdings.

Enable was formed effective May 1, 2013 by the Company, the ArcLight group and CenterPoint to own and operate the midstream businesses of the Company and CenterPoint. In the formation transaction, the Company and the 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's 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 management ownership. Based on the 50/50 management ownership, with neither company having control, effective May 1, 2013, the Company began accounting for its interest in Enable using the equity method of accounting.

In April 2014, Enable completed an initial public offering of 25,000,000 common units resulting in Enable becoming a publicly traded Master Limited Partnership. At December 31, 2015, the Company owned approximately 111.0 million limited partner units, or 26.3 percent, of which 68.2 million limited partner units were subordinated.

On January 22, 2016, Enable announced a quarterly dividend distribution of $0.3180 per unit on its outstanding common and subordinated units, which is unchanged from the previous quarter. Based on current commodity prices, Enable has seen changes in producer activity that have negatively impacted Enable's operations and financial position and could see additional changes in producer activity that may negatively impact Enable's operations and affect its future distribution rates. If cash distributions to Enable’s unitholders exceed $0.330625 per unit in any quarter, the general partner will receive increasing percentages, up to 50 percent, of the cash Enable distributes in excess of that amount. OGE Holdings is entitled to 60 percent of those “incentive distributions.”

OG&E began participating in the SPP Integrated Marketplace effective March 1, 2014. The SPP Integrated Marketplace replaced the SPP Energy Imbalance Services market. As part of the Integrated Marketplace, the SPP assumed balancing authority responsibilities for its market participants. The SPP Integrated Marketplace functions as a centralized dispatch, where market participants, including OG&E, submit offers to sell power to the SPP from their resources and bid to purchase power from the SPP for their customers. The SPP Integrated Marketplace is intended to allow the SPP to optimize supply offers and demand bids based upon reliability and economic considerations, and determine which generating units will run at any given time for maximum cost-effectiveness. As a result, OG&E's generating units produce output that is different from OG&E's customer load requirements. Net fuel and purchased power costs are recovered through fuel adjustment clauses.

Overview

Company Strategy

The Company's mission, through OG&E and its equity interest in Enable, 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 interest in a publicly traded midstream company, while providing competitive energy products and services to customers, as well as seeking growth opportunities in both businesses.

OG&E is focused on:

- Providing exceptional customer experiences by continuing to improve customer interfaces, tools, products and services that deliver high customer satisfaction and operating productivity.
- Providing safe, reliable energy to the communities and customers we serve. A particular focus is on enhancing the value of the grid by improving distribution grid reliability by reducing the frequency and duration of customer interruptions and leveraging previous grid technology investments.
- Maintaining strong regulatory and legislative relationships for the long-term benefit of our customers, investors and members.
- Continuing to grow a zero-injury culture and deliver top-quartile safety results.
- Complying with the EPA's MATS and Regional Haze requirements.
- Ensuring we have the necessary mix of generation resources to meet the long-term needs of our customers.
- Continuing focus on operational excellence and efficiencies in order to protect the customer bill.

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 for OG&E of three to five percent on a weather-normalized basis, maintaining a strong credit rating as well as targeting dividend increases of approximately 10 percent annually through 2019. The targeted annual dividend increase 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 and the composition of the Company's assets and investment opportunities. The Company also relies on cash distributions from its investment in Enable to fund its capital needs and support future dividend growth. 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

2015 compared to 2014. Net income attributable to OGE Energy was $271.3 million, or $1.36 per diluted share, in 2015 as compared to $395.8 million, or $1.98 per diluted share, in 2014. The decrease in net income attributable to OGE Energy of $124.5 million, or 31.5 percent, or $0.62 per diluted share, in 2015 as compared to 2014 was primarily due to:

- a decrease in net income at OGE Holdings of $92.9 million, or 90.8 percent, or $0.46 per diluted share of the Company's common stock, primarily due to the goodwill impairment adjustment at Enable in September 2015 and lower revenues driven by lower average natural gas and NGLs prices;
- a decrease in net income at OGE Energy of $8.5 million, or $0.05 per diluted share of the Company's common stock, primarily due to charges associated with pre-construction expenditures for new office space to consolidate Oklahoma City personnel; and
- a decrease in net income at OG&E of $23.1 million, or 7.9 percent, or $0.11 per diluted share of the Company's common stock, primarily due to an increase in depreciation expense due to additional assets being placed in service in 2015, and a decrease in gross margin related to milder weather and decreased wholesale transmission revenues. Partially offsetting these items was an increase in customer growth, an increase in other income and an increase in allowance for equity funds used during construction.

2014 compared to 2013. Net income attributable to OGE Energy was $395.8 million, or $1.98 per diluted share, in 2014 as compared to $387.6 million, or $1.94 per diluted share, in 2013. The increase in net income attributable to OGE Energy of $8.2 million, or 2.1 percent, or $0.04 per diluted share, in 2014 as compared to 2013 was primarily due to:

- an increase in net income at OGE Holdings of $2.4 million, or 2.4 percent, or $0.01 per diluted share of the Company's common stock, due partially to the accretive effect to OGE Holdings of Enable partially offset by a reduction in deferred state income taxes in 2013 associated with a remeasurement of the accumulated deferred taxes related to the formation of Enable;
- an increase in net income at OGE Energy of $6.4 million, or $0.04 per diluted share of the Company's common stock, primarily due to decreased transaction expenses related to the formation of Enable and a decrease in losses for the deferred compensation plan; and
- a decrease in net income at OG&E of $0.6 million, or 0.2 percent, or $0.01 per diluted share of the Company's common stock, reflecting an increase in depreciation expense due to additional assets being placed in service in 2014, a decrease in gross margin related to milder weather compared to 2013, an increase in other operation and maintenance expense and an increase in interest expense related to the issuance of debt. Partially offsetting these items was an increase in wholesale transmission revenues, an increase in customer growth and a decrease in incentive compensation.

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.

2016 Outlook

Key assumptions for 2016 include:

OG&E

The Company projects OG&E to earn approximately $288 million to $300 million or $1.44 to $1.50 per average diluted share in 2016 and is based on the following assumptions:

- normal weather patterns are experienced for the remainder of the year;
- new rates take effect in Oklahoma in mid 2016;
- gross margin on revenues of approximately $1.405 billion to $1.415 billion based on sales growth of approximately one percent on a weather-adjusted basis;
- approximately $106 million of gross margin is primarily attributed to regionally allocated transmission projects;
- operating expenses of approximately $885 million to $895 million, with operation and maintenance expenses comprising 54 percent of the total;
- interest expense of approximately $140 million which assumes a $8 million allowance for borrowed funds used during construction reduction to interest expense;
- other income of approximately $27 million including approximately $15 million of allowance for equity funds used during construction; 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 the earnings contribution from its ownership interest in Enable Midstream to be approximately $56 million to $66 million or $0.28 to $0.33 per average diluted share.

Consolidated OGE

The Company’s 2016 earnings guidance is between approximately $344 million and $366 million of net income, or $1.72 to $1.83 per average diluted share and is based on the following assumptions:

- approximately 200 million average diluted shares outstanding; and
- an effective tax rate of approximately 29 percent.

Non-GAAP Financial Measures

Ongoing Earnings and Ongoing Earnings per Average Diluted Share are defined by the Company as GAAP Earnings and GAAP Earnings per Average Diluted Share adjusted to exclude non-cash charges. These financial measures excluded non-cash charges of approximately $108.4 million or $0.33 per average diluted share associated with the Company's share of Enable's goodwill impairment as well as a non-cash pension settlement charge of approximately $5.8 million or $0.02 per average diluted share. The Company's management believes that ongoing earnings and ongoing earnings per average diluted share provide a more meaningful comparison of earnings results and are more representative of the Company's fundamental core earnings power. The Company's management uses ongoing earnings and ongoing earnings per average diluted share internally for financial planning and analysis, for reporting of results to the Board of Directors, and when communicating its earnings outlook to analysts and investors. Reconciliations of ongoing earnings and ongoing earnings per average diluted share for the year ended December 31, 2015 and 2014 are below.

Reconciliation of Ongoing Earnings (Loss) to GAAP Earnings (Loss)

(Net of tax, in millions)	**2015 GAAP Earnings (Loss)**	**Goodwill and Pension Settlement Charges (A)**	**2015 Ongoing Earnings (Loss)**	2014 GAAP and Ongoing Earnings (Loss) (B)
OG&E	**$ 268.9**	**$ —**	**$ 268.9**	$ 292.0
Natural Gas Midstream Operations	**9.4**	**70.8**	**80.2**	102.3
Holding Company	**(7.0)**	**—**	**(7.0)**	1.5
Consolidated	**$ 271.3**	**$ 70.8**	**$ 342.1**	$ 395.8

Reconciliation of Ongoing Earnings (Loss) per Average Diluted Share to GAAP Earnings (Loss) per Average Diluted Share

	2015 GAAP Earnings (Loss) per Share	**Goodwill and Pension Settlement Charges per Share (A)**	**2015 Ongoing Earnings (Loss) per Share**	2014 GAAP and Ongoing Earnings (Loss) per Share (B)
OG&E	**$ 1.35**	**$ —**	**$ 1.35**	$ 1.46
Natural Gas Midstream Operations	**0.05**	**0.35**	**0.40**	0.51
Holding Company	**(0.04)**	**—**	**(0.04)**	0.01
Consolidated	**$ 1.36**	**$ 0.35**	**$ 1.71**	$ 1.98

(A) On September 30, 2015, the Company recognized a non-cash pre-tax charge of $108.4 million or $0.33 per average diluted share for its portion of Enable's goodwill impairment. Additionally, the Company recognized a non-cash pre-tax charge of $5.8 million or $0.02 per average diluted share for a pension settlement charge related to Enable.

(B) There were no similar charges for the year ended December 31, 2014, therefore ongoing earnings and GAAP earnings are the same.

Gross margin is defined by OG&E as operating revenues less fuel, purchased power and certain 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 and purchased power 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.

Reconciliation of Gross Margin to Revenue

Year Ended December 31, (Dollars in Millions)		2016 (A)
Operating revenues	$	2,162
Cost of sales		752
Gross Margin	$	1,410

(A) Based on the midpoint of OG&E earnings guidance for 2016.

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, 2015, 2014 and 2013 and the Company's consolidated financial position at December 31, 2015 and 2014. 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)		**2015**		2014		2013
Net income attributable to OGE Energy	**$**	**271.3**	$	395.8	$	387.6
Basic average common shares outstanding		**199.6**		199.2		198.2
Diluted average common shares outstanding		**199.6**		199.9		199.4
Basic earnings per average common share attributable to OGE Energy common shareholders	**$**	**1.36**	$	1.99	$	1.96
Diluted earnings per average common share attributable to OGE Energy common shareholders	**$**	**1.36**	$	1.98	$	1.94
Dividends declared per common share	**$**	**1.05000**	$	0.95000	$	0.85125

Results by Business Segment

	Year Ended December 31,					
(In millions)		**2015**		2014		2013
Net Income attributable to OGE Energy						
OG&E (Electric Utility)	**$**	**268.9**	$	292.0	$	292.6
OGE Holdings (Natural Gas Midstream Operations) (A)		**9.4**		102.3		99.9
Other Operations (B)		**(7.0)**		1.5		(4.9)
Consolidated net income attributable to OGE Energy	**$**	**271.3**	$	395.8	$	387.6

(A) Subsequent to the completion of the October 1, 2014 annual goodwill impairment test and previous interim assessment as of December 31, 2014, the crude oil and natural gas industry was impacted by further commodity price declines, which consequently resulted in decreased producer activity in certain regions in which Enable operates. As a result, when Enable performed the first step of its annual goodwill impairment analysis as of October 1, 2015, it determined that the carrying value of the gathering and processing and transportation and storage segments exceeded fair value. Enable completed the second step of the goodwill impairment analysis comparing the implied fair value for those reporting units to the carrying amount of that goodwill and determined that goodwill for those units was completely impaired in the amount of $1,086.4 million as of September 30, 2015. Accordingly, the Company recorded a $108.4 million pre-tax charge during the third quarter of 2015 for its share of the goodwill impairment, as adjusted for the basis differences. See Note 3 for further discussion of Enable's goodwill impairment.

(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)*	**2015**	2014	2013
Operating revenues	**$ 2,196.9**	$ 2,453.1	$ 2,262.2
Cost of sales	**865.0**	1,106.6	965.9
Other operation and maintenance	**444.5**	453.2	438.8
Depreciation and amortization	**299.9**	270.8	248.4
Taxes other than income	**87.1**	84.5	83.8
Operating income	**500.4**	538.0	525.3
Allowance for equity funds used during construction	**8.3**	4.2	6.6
Other income	**13.3**	4.8	8.1
Other expense	**1.6**	1.9	4.6
Interest expense	**146.7**	141.5	129.3
Income tax expense	**104.8**	111.6	113.5
Net income	**$ 268.9**	$ 292.0	$ 292.6
Operating revenues by classification			
Residential	**$ 896.5**	$ 925.5	$ 901.4
Commercial	**535.0**	583.3	554.2
Industrial	**190.6**	224.5	220.6
Oilfield	**162.8**	188.3	176.4
Public authorities and street light	**194.2**	220.3	214.3
Sales for resale	**21.7**	52.9	59.4
System sales revenues	**2,000.8**	2,194.8	2,126.3
Off-system sales revenues	**48.6**	94.1	14.7
Other	**147.5**	164.2	121.2
Total operating revenues	**$ 2,196.9**	$ 2,453.1	$ 2,262.2
Reconciliation of gross margin to revenue:			
Operating revenues	**$ 2,196.9**	$ 2,453.1	$ 2,262.2
Cost of sales	**865.0**	1,106.6	965.9
Gross Margin	**$ 1,331.9**	$ 1,346.5	$ 1,296.3
MWh sales by classification *(In millions)*			
Residential	**9.2**	9.4	9.4
Commercial	**7.4**	7.2	7.1
Industrial	**3.6**	3.8	3.9
Oilfield	**3.4**	3.4	3.4
Public authorities and street light	**3.1**	3.2	3.2
Sales for resale	**0.5**	1.0	1.2
System sales	**27.2**	28.0	28.2
Off-system sales	**1.7**	2.2	0.4
Total sales	**28.9**	30.2	28.6
Number of customers	**824,776**	814,982	806,940
Weighted-average cost of energy per kilowatt-hour - cents			
Natural gas	**2.529**	4.506	3.905
Coal	**2.187**	2.152	2.273
Total fuel	**2.196**	2.752	2.784
Total fuel and purchased power	**2.874**	3.493	3.178
Degree days (A)			
Heating - Actual	**3,038**	3,569	3,673
Heating - Normal	**3,349**	3,349	3,349
Cooling - Actual	**2,071**	2,114	2,106
Cooling - Normal	**2,092**	2,092	2,092

(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.

2015 compared to 2014. OG&E's net income decreased $23.1 million, or 7.9 percent, in 2015 as compared to 2014 primarily due to higher depreciation expense and lower gross margin partially offset by higher other income and an increase in allowance for equity funds used in construction.

Gross Margin

Operating revenues were $2,196.9 million in 2015 as compared to $2,453.1 million in 2014, a decrease of $256.2 million, or 10.4 percent. Cost of sales were $865.0 million in 2015 as compared to $1,106.6 million in 2014, a decrease of $241.6 million, or 21.8 percent. Gross margin was $1,331.9 million in 2015 as compared to $1,346.5 million in 2014, a decrease of $14.6 million, or 1.1 percent. The below factors contributed to the change in gross margin:

(In millions)	$ Change
Quantity variance (primarily weather) (A)	$ (25.8)
Wholesale transmission revenue (B)	(19.8)
Expiration of AVEC contract (C)	(11.5)
Industrial and oilfield sales	(4.5)
Other	2.1
Non-residential demand and related revenues	3.7
Price Variance (D)	19.8
New customer growth	21.4
Change in gross margin	$ (14.6)

(A) The overall cooling degree days decreased two percent in 2015 compared to 2014 with August decreasing by 14 percent.
(B) Decreased primarily due to a true up for the base plan projects in the SPP formula rate for 2014 and 2015 as well as a reduction in the point-to-point credits shared with retail customers.
(C) On June 30, 2015, the wholesale power contract with AVEC expired.
(D) Increased 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 $458.5 million in 2015 as compared to $627.5 million in 2014, a decrease of $169.0 million, or 26.9 percent, primarily due to lower natural gas prices offset by higher natural gas used. In 2015, OG&E's fuel mix was 49.0 percent coal, 44.0 percent natural gas and seven percent wind. In 2014, OG&E's fuel mix was 61.0 percent coal, 32.0 percent natural gas and seven percent wind. Purchased power costs were $362.6 million in 2015 as compared to $444.1 million in 2014, a decrease of $81.5 million, or 18.4 percent, primarily due to a decrease in purchases from the SPP, reflecting the impact of OG&E's participation in the SPP Integrated Marketplace, which began on March 1, 2014. Transmission related charges were $43.9 million in 2015 as compared to $35.0 million in 2014, an increase of $8.9 million, or 25.4 percent, primarily due to higher SPP charges for the base plan projects of other utilities.

The actual cost of fuel used in electric generation and certain purchased power costs 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 $444.5 million in 2015 as compared to $453.2 million in 2014, a decrease of $8.7 million, or 1.9 percent. The below factors contributed to the change in other operations and maintenance expense:

(In millions)	$ Change
Additional capitalized labor (A)	$ (9.2)
Maintenance at power plants (B)	(7.0)
Professional service contracts (C)	(2.1)
Other	(1.0)
Employee benefits (D)	1.0
Other marketing, sales and commercial (E)	2.8
Salaries and wages (F)	6.8
Change in other operation and maintenance expense	$ (8.7)

(A) Decreased primarily due to more capital projects and storm costs exceeding the $2.7 million threshold, which were moved to a regulatory asset.
(B) Decreased primarily due to less work at the power plants.
(C) Decreased primarily due to decreased engineering services.
(D) Increased primarily due to higher medical costs incurred partially offset by lower pension costs.
(E) Increased primarily due to higher demand side management customer payments.
(F) Increased primarily due to annual salary increases and increased overtime related to storms.

Depreciation and amortization expense was $299.9 million in 2015 as compared to $270.8 million in 2014, an increase of $29.1 million, or 10.7 percent, primarily due to additional assets being placed in service, along with an increase resulting from the amortization of deferred pension credits and post-retirement medical regulatory liabilities which were fully amortized in July 2014 and amortization of deferred storm costs.

Additional Information

Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction was $8.3 million in 2015 as compared to $4.2 million in 2014, an increase of $4.1 million or 97.6 percent, primarily due to higher construction work in progress balances resulting from increased spending for environmental projects.

Other Income. Other income was $13.3 million in 2015 as compared to $4.8 million in 2014, an increase of $8.5 million , primarily due to increased guaranteed flat bill margins and an increase in the tax gross up related to higher allowance for funds used during construction.

Income Tax Expense. Income tax expense was $104.8 million in 2015 as compared to $111.6 million in 2014, a decrease of $6.8 million, or 6.1 percent, primarily due to lower pretax income partially offset by a reduction in Federal tax credits.

2014 compared to 2013. OG&E's net income decreased $0.6 million, or 0.2 percent, in 2014 as compared to 2013 primarily due to higher gross margin, which was almost offset by higher other operations and maintenance expense, higher depreciation and amortization expense, and interest expense.

Gross Margin

Operating revenues were $2,453.1 million in 2014 as compared to $2,262.2 million in 2013, an increase of $190.9 million, or 8.4 percent. Cost of sales were $1,106.6 million in 2014 as compared to $965.9 million in 2013, an increase of $140.7 million, or 14.6 percent. Gross margin was $1,346.5 million in 2014 as compared to $1,296.3 million in 2013, an increase of $50.2 million, or 3.9 percent. The below factors contributed to the change in gross margin:

(In millions)	$ Change
Wholesale transmission revenue (A)	$ 43.8
New customer growth	13.8
Price variance (B)	6.8
Non-residential demand and related revenues	1.4
Other	(1.7)
Quantity variance (primarily weather)	(13.9)
Change in gross margin	$ 50.2

(A) Increased primarily due to higher investments related to certain FERC approved transmission projects included in formula rates.

(B) Increased due to higher rider revenues primarily from the Oklahoma Demand Program rider, the Oklahoma Storm Recovery rider and the Arkansas Demand Program rider partially offset by lower rider revenues from the Oklahoma Crossroads rider, Oklahoma Smart Grid rider, Oklahoma System Hardening rider and the Arkansas Crossroads rider.

Cost of sales for OG&E consists of fuel used in electric generation, purchased power and transmission related charges. Fuel expense was $627.5 million in 2014 as compared to $672.7 million in 2013, a decrease of $45.2 million, or 6.7 percent, primarily due to lower natural gas used offset by higher natural gas prices. In 2014, OG&E's fuel mix was 61 percent coal, 32 percent natural gas and seven percent wind. In 2013, OG&E's fuel mix was 53.0 percent coal, 40.0 percent natural gas and seven percent wind. Purchased power costs were $444.1 million in 2014 as compared to $267.6 million in 2013, an increase of $176.5 million, or 66.0 percent, primarily due to an increase in purchases from the SPP, reflecting the impact of OG&E's participation in the SPP Integrated Marketplace, which began on March 1, 2014. Transmission related charges were $35.0 million in 2014 as compared to $25.6 million in 2013, an increase of $9.4 million, or 36.7 percent, primarily due to higher SPP charges for the base plan projects of other utilities.

Operating Expenses

Other operation and maintenance expenses were $453.2 million in 2014 as compared to $438.8 million in 2013, an increase of $14.4 million, or 3.3 percent. The below factors contributed to the change in other operations and maintenance expense:

(In millions)	$ Change
Reduction in capitalized labor (A)	$ 11.4
Corporate overhead and allocations (B)	4.0
Contract professional services (primarily marketing services)	3.8
Ongoing maintenance at power plants	3.5
Other marketing, sales and commercial (C)	2.3
Software expense (D)	2.3
Fees, permits and licenses (E)	2.3
Vegetation management (F)	(4.5)
Employee benefits (G)	(4.9)
Salaries and wages (H)	(5.8)
Change in other operation and maintenance expense	$ 14.4

(A) Portion of labor costs capitalized into projects decreased as a result of less work performed on storm restoration.
(B) Increased primarily due to higher allocated costs from the holding company resulting from the formation of Enable during 2013.
(C) Increased primarily due to demand side management customer payments which are recovered through a rider partially offset by a reduction in media services expense.
(D) Increased as a result of higher expenditures related to Smart Grid software.
(E) Increased primarily due to higher SPP administration and assessment fees.
(F) Decreased primarily due to increased spending on system hardening in 2013 which includes costs that are being recovered through a rider.
(G) Decreased primarily due to lower pension expense, postretirement and other benefits.
(H) Decreased primarily due to incentive compensation and lower overtime wages partially offset by higher regular salaries and wages.

Depreciation and amortization expense was $270.8 million in 2014 as compared to $248.4 million in 2013, an increase of $22.4 million, or nine percent, primarily due to additional transmission assets being placed in service throughout 2013 and 2014, along with an increase resulting from the amortization of the deferred pension credits regulatory liability which was fully amortized in July 2014. These were offset by the pension regulatory asset which was fully amortized in July 2013.

Additional Information

Allowance for Equity Funds Used During Construction. Allowance for equity funds used during construction was $4.2 million in 2014 as compared to $6.6 million in 2013, a decrease of $2.4 million or 36.4 percent, primarily due to lower construction work in progress balances resulting from transmission projects being placed in service in 2014.

Other Income. Other income was $4.8 million in 2014 as compared to $8.1 million in 2013, a decrease of $3.3 million or 40.7 percent, primarily due to decreased margins recognized in the guaranteed flat bill program during 2014 as a result of cooler weather in the first quarter as compared to the same period in 2013 along with a decrease in the tax gross up related to the allowance for equity funds used during construction.

Other Expense. Other expense was $1.9 million in 2014 as compared to $4.6 million in 2013, a decrease of $2.7 million or 58.7 percent, primarily due to decreased charitable donations during 2014.

Interest Expense. Interest expense was $141.5 million in 2014 as compared to $129.3 million in 2013, an increase of $12.2 million, or 9.4 percent, primarily due to a $9.1 million increase in interest on long-term debt related to a $250.0 million debt issuance that occurred in May 2013, a $250.0 million debt issuance that occurred in March 2014 and an additional $250.0 million debt issuance that occurred in December 2014 partially offset by the early redemption of $140.0 million senior notes in August 2014. In addition, there was a $2.0 million increase reflecting a reduction in 2013 interest expense related to tax matters offset by a decrease in the allowance for borrowed funds used during construction of $1.0 million.

Income Tax Expense. Income tax expense was $111.6 million in 2014 as compared to $113.5 million in 2013, a decrease of $1.9 million, or 1.7 percent. The reduction reflects lower pretax income partially offset by a reduction in state tax credits recognized during the year and an increase in Federal credits recognized.

OGE Holdings (Natural Gas Midstream Operations)

	Year Ended December 31,		
(In millions)	**2015**	2014	2013
Operating revenues	**$ —**	$ —	$ 630.4
Cost of sales	**—**	—	489.0
Other operation and maintenance	**7.5**	1.2	60.9
Depreciation and amortization	**—**	—	36.8
Taxes other than income	**—**	—	10.5
Operating income (loss)	**(7.5)**	(1.2)	33.2
Equity in earnings of unconsolidated affiliates (A)	**15.5**	172.6	101.9
Other income	**0.4**	—	10.2
Other expense	**—**	—	1.3
Interest expense	**—**	—	10.6
Income tax expense	**(1.0)**	69.1	26.9
Net income	**9.4**	102.3	106.5
Less: Net income attributable to noncontrolling interests	**—**	—	6.6
Net income attributable to OGE Holdings	**$ 9.4**	$ 102.3	$ 99.9

(A) In September 2015, the Company recorded a $108.4 million pre-tax charge for its share of the goodwill impairment, as adjusted for the basis difference. See Note 3 for further discussion of Enable's goodwill impairment.

Effective May 1, 2013, the Company deconsolidated its previously held investment in Enogex Holdings and acquired a 28.5 percent equity interest in Enable (26.3 percent as of December 31, 2015) which is being accounted for using the equity method of accounting. Prior to May 1, 2013, the Company reported the results of Enogex Holdings in the natural gas midstream operations segment.

Equity in earnings of unconsolidated affiliates includes OGE Energy's share of Enable earnings adjusted for the amortization of the basis difference of OGE Energy's original investment in Enogex LLC and its underlying equity in net assets of Enable. The basis difference is the result of the initial contribution of Enogex LLC to Enable in May 2013, and subsequent issuances of equity by Enable, including the initial public offering in April 2014 and the issuance of common units for the acquisition of CenterPoint's 24.95 percent interest in SESH. 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.

The difference between OGE Energy's investment in Enable and its underlying equity in the net assets of Enable was $783.5 million as of December 31, 2015.

Reconciliation of Equity in Earnings of Unconsolidated Affiliates

The following table reconciles OGE Energy's equity in earnings of its unconsolidated affiliates for the years ended December 31, 2015 and 2014.

	Year Ended December 31,	
(In millions)	**2015**	2014
OGE's share of Enable Net Income (Loss)	**$ (16.0)**	$ 143.1
Amortization of basis difference	**13.5**	14.0
Elimination of Enogex Holdings fair value and other adjustments	**18.0**	15.5
Equity in earnings of unconsolidated affiliates	**$ 15.5**	$ 172.6

The following table represents summarized financial information of Enable for 2014 and 2015:

Enable Results of Operations

	Year Ended December 31,	
(In millions)	**2015**	2014
Operating revenues	**$ 2,418**	$ 3,367
Cost of natural gas and natural gas liquids	**1,097**	1,914
Operating income (loss)	**(712)**	586
Net income (loss)	**$ (752)**	$ 530

Year Ended December 31, 2015 as Compared to Year Ended December 31, 2014

The table set forth below illustrates the impact of the operating results of Enable for the years ended December 31, 2015 and 2014.

	Year Ended December 31,	
(In millions)	**2015**	2014
Operating revenues	**$ —**	$ —
Cost of natural gas and natural gas liquids	**—**	—
Other operation and maintenance	**7.5**	1.2
Depreciation and amortization	**—**	—
Taxes other than income	**—**	—
Operating income (loss)	**(7.5)**	(1.2)
Equity in earnings of unconsolidated affiliates (A)	**15.5**	172.6
Other income/(expense)	**0.4**	—
Income before taxes	**8.4**	171.4
Income tax expense (benefit)	**(1.0)**	69.1
Net income attributable to OGE Holdings	**$ 9.4**	$ 102.3

(A) The Company recorded a $108.4 million pre-tax charge during the third quarter of 2015 for its share of the goodwill impairment, as adjusted for the basis differences. See Note 3 for further discussion of Enable's goodwill impairment.

OGE Holdings' earnings before taxes decreased $163.0 million, or 95.1 percent, for the year ended December 31, 2015 as compared to the same period of 2014 primarily due to a decrease in equity in earnings of Enable of $157.1 million. In addition to the goodwill impairment, Enable's gathering and processing business segment reported a decrease in operating income primarily from a decrease in gross margin, an increase in depreciation and amortization expense and an increase in taxes other than income taxes. Gathering and processing gross margin decreased primarily due to lower commodity prices partially offset by increased volumes in the Anadarko and Williston basins. In addition to the goodwill impairment, Enable’s transportation and storage segment reported a decrease in operating income primarily due to lower margin on unrealized natural gas derivatives, a decrease in sales of NGLs due to lower prices, lower firm transportation revenues, a decrease in storage demand fees as well as lower rates on transportation services for local distribution companies and increased depreciation expenses. These decreases were partially offset by higher margins related to realized gains on system optimization activities and increased margins from higher rates on off-system transportation services.

Over the course of 2015 and continuing into 2016, natural gas and crude oil prices have dropped to their lowest levels in over 10 years. Should lower commodity prices persist, or should commodity prices decline further, Enable's future operating results and cash flows could be negatively impacted.

Income Tax Expense. Income tax benefit was $1.0 million in 2015 as compared to an expense of $69.1 million in 2014, a decrease in expense of $70.1 million primarily due to lower pre-tax operating income, a benefit recognized associated with a remeasurement of deferred taxes related to the Company's investment in Enable and the impact of the goodwill impairment on Enable.

Operating Data

	Year Ended December 31,	
	2015	2014
Gathered volumes - TBtu/d	**3.14**	3.34
Transportation volumes - TBtu/d	**4.97**	4.95
Natural gas processed volumes - TBtu/d	**1.78**	1.56
NGLs sold - million gallons/d (A)(B)	**75.55**	68.67

(A) Excludes condensate.
(B) NGLS sold includes volumes of NGLS withdrawn from inventory or purchased for system balancing purposes.

Year Ended December 31, 2014 as Compared to Year Ended December 31, 2013

Due to deconsolidation of Enogex LLC on May 1, 2013, the Company recorded no operating income for this segment for the eight-month period from May 1, 2013 through December 31, 2013 or the year ended December 31, 2014. Earnings after May 1, 2013 reflect the Company's equity interest in Enable's results, which are recorded in equity in earnings of unconsolidated affiliate, and the related tax effect. The table set forth below illustrates the impact of the operating results of Enable for the year ended December 31, 2014 as compared to the combined results of Enogex LLC for the four months ended April 30, 2013 and Enable for the eight months from May 1, 2013 to December 31, 2013.

	Enable Midstream Partners (Equity Method - Year Ended December 31, 2014)	Natural Gas Midstream Operations (Consolidated - Four Months Ended April 30, 2013)	Enable Midstream Partners (Equity Method - Eight Months Ended December 31, 2013)	Total (Year Ended December 31, 2013)
(In millions)				
Operating revenues	$ —	$ 630.4	$ —	$ 630.4
Cost of sales	—	489.0	—	489.0
Operating expenses	1.2	108.2	—	108.2
Operating income (loss)	(1.2)	33.2	—	33.2
Equity in earnings of unconsolidated affiliates	172.6	—	101.9	101.9
Other income (expense)	—	8.9	—	8.9
Interest expense	—	10.6	—	10.6
Earnings before taxes	171.4	31.5	101.9	133.4
Income tax expense	69.1	9.4	17.5	26.9
Net income	102.3	22.1	84.4	106.5
Less: net income attributable to noncontrolling interests	—	6.6	—	6.6
Net income attributable to OGE Holdings	$ 102.3	$ 15.5	$ 84.4	$ 99.9

OGE Holdings' net income decreased $4.2 million, or four percent for the year ended December 31, 2014 as compared to the same period of 2013 due to higher pre-tax income and higher tax expense. OGE Holdings' earnings before taxes increased $38.0 million, or 28.5 percent, for the year ended December 31, 2014 as compared to the same period of 2013. The increase reflects the accretive effect to OGE Holdings of Enable, for the entire year of 2014, as compared to only eight months of 2013, following the formation of Enable on May 1, 2013. Enable's operating results for 2014 improved as compared to 2013, due to increased gathering and processing margins as a result of higher processed volumes in the Anadarko and Ark-La-Tex basins (which offset lower gathering volumes) and higher crude oil gathering margins. Additionally, Enable's operating results for 2014 improved as compared to 2013 due to higher transportation and storage margins as a result of an increase of unrealized gains on natural gas derivatives and an increase of system optimization activities. The higher margins were offset in part, by higher depreciation expenses resulting from assets being placed in service and higher operating and maintenance expenses. Finally, as a result of Enable's initial public offering in April 2014, and CenterPoint's exercising of its put right to Enable, for its 24.95 percent interest in SESH, OGE Energy's ownership in Enable dropped from 28.5 percent at the beginning of 2014 to 26.3 percent by the end of 2014, further partially offsetting the increase in earnings before taxes.

Income Tax Expense. Income tax expense was $69.1 million in 2014 as compared to $26.9 million in 2013, an increase of $42.2 million primarily due to higher pre-tax income and higher tax expense as compared to the prior period due to the absence of favorable deferred tax adjustments related to the formation of Enable.

Off-Balance Sheet Arrangement

OG&E Railcar Lease Agreement

OG&E has several noncancellable operating leases with purchase options, covering approximately 1,400 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 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.

On October 14, 2014, OG&E signed a separate three-year lease effective December 2014 for 131 railcars to replace railcars that have been taken out of service or destroyed.

On December 17, 2015, OG&E renewed the lease agreement effective February 1, 2016. At the end of the new lease term, which is February 1, 2019, 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 $20.1 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.

Liquidity and Capital Resources

Working Capital

Working capital is defined as the difference in current assets and 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.

Cash and Cash Equivalents. The balance of Cash and Cash Equivalents was $75.2 million and $5.5 million at December 31, 2015 and 2014, respectively, an increase of $69.7 million, primarily due to normal business operations and the quarterly distributions received from Enable.

Accounts Receivable and Accrued Unbilled Revenues. The balance of Accounts Receivable and Accrued Unbilled Revenues was $228.3 million and $249.9 million at December 31, 2015 and 2014, respectively, a decrease of $21.6 million, or 8.6 percent, primarily due to a decrease in billings to OG&E's retail customers.

Income Taxes Receivable. The balance of Income Taxes Receivable was $17.2 million and $16.0 million at December 31, 2015 and 2014, respectively, an increase of $1.2 million,or 7.5 percent, primarily due to a receivable related to Oklahoma wind credits and overpayments refundable from Louisiana.

Fuel Inventories. The balance of Fuel Inventories was $113.8 million and $58.5 million at December 31, 2015 and 2014, respectively, an increase of $55.3 million, or 94.5 percent, primarily due to higher coal inventory balances at OG&E's coal fired plants resulting from lower participation in the SPP Integrated Marketplace.

Deferred Income Tax. Deferred Income Tax assets had no balance as of December 31, 2015 compared to $191.4 million at December 31, 2014, due to a reclassification of the balance to Non-Current Deferred Income Taxes pursuant to early adoption of ASU 2015-17 “Income Taxes (Topic 740)”.

Fuel Clause Recoveries. The Fuel Clause balance moved from an under recovery position of $68.3 million as of December 31, 2014 to an over recovery balance of $61.3 million as of December 31, 2015, primarily due to higher amounts billed to OG&E retail customers as compared to the actual cost of fuel and purchased power. The 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 when the actual fuel and purchased power cost recoveries exceed fuel adjustment clause recoveries and over recovers fuel costs when the actual fuel and purchased power costs are below the fuel adjustment clause recoveries. Provisions in the fuel clauses are intended to allow OG&E to amortize under and over recovery balances into future cost recoveries.

Other Current Assets. The balance of Other Current Assets was $55.6 million and $38.4 million at December 31, 2015 and 2014, respectively, an increase of $17.2 million, or 44.8 percent, primarily due to an increase in recoverable demand portfolio program costs.

Short-Term Debt. Short-Term Debt had no balance at December 31, 2015 compared to a balance of $98 million at December 31, 2014, due to a payoff of all short-term debt.

Accounts Payable. The balance of Accounts Payable was $262.5 million and $179.1 million at December 31, 2015 and 2014, respectively, an increase of $83.4 million, or 46.6 percent, primarily due to storm accruals and timing of vendor payments partially offset by a decrease of fuel and purchased power expense.

Accrued Compensation. The balance of Accrued Compensation was $54.4 million and $38.2 million at December 31, 2015 and 2014, respectively, an increase of $16.2 million, or 42.4 percent, primarily resulting from the reclassification of retirement restoration payable in the second quarter of 2016 to accrued compensation as well as lower levels of accrued incentive compensation for 2014.

Long-Term Debt Due Within One Year. The balance of Long-Term Debt Due Within One Year was $110.0 million at December 31, 2015 compared to no balance at December 31, 2014 due to the reclassification of long-term debt that will mature in January 2016.

Cash Flows

				2015 vs. 2014		2014 vs. 2013	
Year ended December 31 *(In millions)*	**2015**	2014	2013	$ Change	% Change	$ Change	% Change
Net cash provided from operating activities	**$ 865.4**	$ 721.6	$ 623.2	$ 143.8	19.9 %	$ 98.4	15.8%
Net cash used in investing activities	**(500.1)**	(559.1)	(957.0)	59.0	10.6 %	397.9	41.6%
Net Cash (Used in) Provided from Financing Activities	**(295.6)**	(163.8)	338.8	(131.8)	(80.5)%	(502.6)	*

* Greater than a 100 percent variance.

Operating Activities

The increase of $143.8 million, or 19.9 percent, in net cash provided from operating activities in 2015 as compared to 2014 was primarily due to an increase in cash received from fuel recoveries at OG&E and less cash paid to vendors, partially offset by Enable distributions classified as a return of capital in investing activities.

The increase of $98.4 million, or 15.8 percent, in net cash provided from operating activities in 2014 as compared to 2013 was primarily due to:

- the absence of fuel refunds to customers during the twelve months ended December 31, 2014, partially offset by fuel under recoveries in the same period;
- an increase in cash distributions received from Enable in excess of cash distributions and cash provided from the operating activities of Enogex Holdings in 2013; and
- an increase in cash received during the twelve months ended December 31, 2014 from transmission revenue.

These increases were partially offset by an increase in amounts paid to vendors.

Investing Activities

The decrease of $59.0 million, or 10.6 percent, in net cash used in investing activities in 2015 as compared to 2014 was primarily due to an increase in investments related to return of capital from Enable and a decrease in capital expenditures related to transmission projects completed in 2014 partially offset by an increase in capital expenditures related to environmental projects at OG&E.

The decrease of $397.9 million, or 41.6 percent, in net cash used in investing activities in 2014 as compared to 2013 was primarily due to lower levels of capital expenditures due to a decrease in transmission projects at OG&E and the deconsolidation of Enogex Holdings.

Financing Activities

The increase of $131.8 million, or 80.5 percent in net cash used in financing activities in 2015 as compared to 2014 was primarily due to the issuance of long-term debt during 2014 and an increase in dividends paid in 2015, which was partially offset by a decrease in short-term debt and the payment of $240.0 million in long-term debt during the third quarter during 2014.

The increase of $502.6 million in net cash used in financing activities in 2014 as compared to 2013 was primarily due to:

- a decrease in short-term debt;
- the payment to retire $240.0 million of long-term debt in 2014;
- payments in 2013 on advances from unconsolidated affiliates due to the deconsolidation of Enogex Holdings; and
- contributions in 2013 from the ArcLight group related to the closing of the transaction to form Enable.

These increases were partially offset by proceeds received from the issuance of long-term debt in 2014.

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 2016 through 2020 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. Estimated capital expenditures for Enable are not included in the table below.

(In millions)	2016	2017	2018	2019	2020
OG&E Base Transmission	$ 50	$ 30	$ 30	$ 30	$ 30
OG&E Base Distribution	190	175	175	175	175
OG&E Base Generation	60	75	75	75	75
OG&E Other	40	25	25	25	25
Total Base Transmission, Distribution, Generation and Other	340	305	305	305	305
OG&E Known and Committed Projects:					
Transmission Projects:					
Other Regionally Allocated Projects (A)	50	25	20	20	20
Large SPP Integrated Transmission Projects (B) (C)	20	150	20	—	—
Total Transmission Projects	70	175	40	20	20
Other Projects:					
Environmental - low NO_X burners (D)	20	10	—	—	—
Environmental - natural gas conversion (D)	—	—	40	35	—
Environmental - dry scrubbers (D)	150	140	90	20	—
Combustion turbines - Mustang	180	100	50	5	—
Total Other Projects	350	250	180	60	—
Total Known and Committed Projects	420	425	220	80	20
Total	$ 760	$ 730	$ 525	$ 385	$ 325

(A) Typically 100kV to 299kV projects. Approximately 30 percent of revenue requirement allocated to SPP members other than OG&E.
(B) Typically 300kV and above projects. Approximately 85 percent of revenue requirement allocated to SPP members other than OG&E.

(C)

Project Type	Project Description	Estimated Cost (In millions)	Projected In-Service Date
Integrated Transmission Project	30 miles of transmission line from OG&E's Gracemont substation to an AEP companion transmission line to its Elk City substation. Approximately $5.0 million of the estimated cost has been spent prior to 2016.	$45	Late 2017
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. Approximately $55.0 million of the estimated cost associated with the Mathewson to Cimarron line and substations will go into service in 2016; $35.0 million has been spent prior to 2016.	$190	Mid 2018

(D) Represent capital costs associated with OG&E’s ECP to comply with the EPA’s MATS and Regional Haze rules. More detailed discussion regarding Regional Haze and OG&E’s ECP can be found in Note 15 of Notes to Financial Statements under "Environmental Compliance Plan" in Item 8 of Part II of this Form 10-K, and under “Environmental Laws and Regulations” within “Management's Discussion and Analysis of Financial Condition and Results of Operations” under Part II, Item 7 of this Form 10-K. On February 12, 2016, OG&E filed an application requesting the OCC to issue an order approving the installation of dry scrubbers at the Sooner facility, on or before May 2, 2016. The application states that if the application is not approved by May 2, 2016, OG&E will decide at that time whether to cancel the dry scrubber equipment and installation contracts and make plans to convert the Sooner coal units to natural gas. As of December 31, 2015, OG&E had incurred $94.8 million of construction work in progress on the dry scrubbers. OG&E estimates another $35.0 million of in-process expenditures will be incurred prior to May 1, 2016. Additionally, if the request is not approved, OG&E expects to seek recovery in subsequent proceedings for the expenditures incurred for the dry scrubber project and reasonable stranded costs associated with the discontinuance of the Sooner coal units. The capital costs in the table above do not reflect any actions or costs that may be incurred (including the conversion of the Sooner coal units) if the May 2, 2016 application is not approved.

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, 2015. See the Company's Consolidated Statements of Capitalization and Note 14 of Notes to Consolidated Financial Statements for additional information.

(In millions)	2016	2017-2018	2019-2020	After 2020	Total
Maturities of long-term debt (A)	$ 110.2	$ 475.3	$ 250.2	$ 1,929.9	$ 2,765.6
Operating lease obligations					
Railcars	4.2	5.9	23.0	—	33.1
Wind farm land leases	2.4	5.0	5.4	46.3	59.1
Noncancellable operating lease	0.8	1.5	—	—	2.3
Total operating lease obligations	7.4	12.4	28.4	46.3	94.5
Other purchase obligations and commitments					
Cogeneration capacity and fixed operation and maintenance payments	79.8	151.0	121.3	99.7	451.8
Expected cogeneration energy payments	58.3	97.9	112.7	120.5	389.4
Minimum fuel purchase commitments	299.6	168.2	11.7	—	479.5
Expected wind purchase commitments	58.6	115.8	112.4	632.6	919.4
Long-term service agreement commitments	2.5	45.8	5.7	137.4	191.4
Mustang Modernization expenditures	103.4	30.6	—	—	134.0
Environmental compliance plan expenditures	150.5	170.7	4.1	—	325.3
Total other purchase obligations and commitments	752.7	780.0	367.9	990.2	2,890.8
Total contractual obligations	870.3	1,267.7	646.5	2,966.4	5,750.9
Amounts recoverable through fuel adjustment clause (B)	(420.7)	(387.8)	(259.8)	(753.1)	(1,821.4)
Total contractual obligations, net	$ 449.6	$ 879.9	$ 386.7	$ 2,213.3	$ 3,929.5

(A) Maturities of the Company's long-term debt during the next five years consist of $110.2 million, $225.2 million, $250.1 million, $250.1 million and $0.1 million in years 2016, 2017, 2018, 2019 and 2020, 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, 2015, 35.5 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, and a commingled fund as presented in Note 12 of Notes to Consolidated Financial Statements. In 2015, asset losses on the Pension Plan were 3.9 percent due to the losses 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, decreased. The level of funding is dependent on returns on plan assets and future discount rates. During 2015 and 2014, OGE Energy did not make any contributions to its Pension Plan. The Company has not determined whether it will need to make any contributions to the Pension Plan in 2016. The Company 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, 2015 and 2014. 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 Sheets. 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)*	**2015**	2014	**2015**	2014	**2015**	2014
Benefit obligations	**$ 680.0**	$ 725.0	**$ 25.1**	$ 19.7	**$ 225.3**	$ 280.9
Fair value of plan assets	**581.7**	679.8	**—**	—	**55.3**	59.6
Funded status at end of year	**$ (98.3)**	$ (45.2)	**$ (25.1)**	$ (19.7)	**$ (170.0)**	$ (221.3)

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 2015, 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, the Company recorded pension settlement charges of $16.2 million in the third quarter and $5.5 million in the fourth quarter of 2015, of which $14.0 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 dividend increases of approximately 10 percent annually through 2019. The targeted annual dividend increase 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 and the composition of the Company's assets and investment opportunities. At the Company's September 2015 board meeting, the Board of Directors approved management's recommendation of a 10 percent increase in the quarterly dividend rate to $0.27500 per share from $0.25000 per share effective in October 2015.

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.

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.

2015 Capital Requirements, Sources of Financing and Financing Activities

Total capital requirements, consisting of capital expenditures and maturities of long-term debt, were $548.0 million and contractual obligations, net of recoveries through fuel adjustment clauses, were $85.6 million resulting in total net capital requirements and contractual obligations of $633.6 million in 2015, of which $130.6 million was to comply with environmental regulations. This compares to net capital requirements of $809.5 million and net contractual obligations of $88.2 million totaling $897.7 million in 2014, of which $31.5 million was to comply with environmental regulations.

In 2015, the Company's sources of capital were cash generated from operations, proceeds from the issuance of short and long-term debt, proceeds from the sales of common stock 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.

The Dodd-Frank Act

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. On January 12, 2015, President Obama signed into law an amendment to the Dodd-Frank Act that exempts from margin requirements swaps used by end-users to hedge or mitigate commercial risk. There are, however, some rulemakings that have no yet been finalized. 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 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 agreement. 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. Short-term debt had no balance at December 31, 2015 compared to a balance of $98.0 million at December 31, 2014. The average balance of short-term debt in 2015 was $75.2 million at a weighted-average interest rate of 0.46 percent. The maximum month-end balance of short-term debt in 2015 was $180.0 million. At December 31, 2015, the Company had $1,148.1 million of net available liquidity under its revolving credit agreements. OG&E has the necessary regulatory approvals to incur up to $800.0 million in short-term borrowings at any one time for a two-year period beginning January 1, 2015 and ending December 31,

2016. At December 31, 2015, the Company had $75.2 million in cash and cash equivalents. See Note 11 of Notes to Consolidated Financial Statements for a discussion of the Company's short-term debt activity.

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 contained an option, which could be exercised up to two times, to extend the term for an additional year. In the third quarter of 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 from December 13, 2016 to December 13, 2017. In the second quarter of 2014, the Company and OG&E utilized their second extension to extend the maturity of their respective credit facility from December 13, 2017 to December 13, 2018. As of December 31, 2015, commitments of approximately $16.3 million and $8.7 million of the Company's and OG&E's credit facilities, respectively, however, were not extended and, unless the non-extending lender is replaced in accordance with the terms of the credit facility, such commitments will expire December 13, 2017.

Common Stock

The Company does not expect to issue any common stock in 2016 from its Automatic Dividend Reinvestment and Stock Purchase Plan. See Note 9 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, the amount of distributions the Company received from Enable were $139.3 million and $143.7 million during the years ended December 31, 2015 and 2014.

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, income taxes, contingency reserves, asset retirement obligations and depreciable lives of property, plant and equipment. For the electric utility segment, significant judgment is also exercised in the determination 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 12 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	+/- $5.8 million
Discount rate	+/- 0.25 percent	+/- $14.1 million
Contributions	+/- $10 million	+/- $10.0 million

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.

Asset Retirement Obligations

The Company has previously recorded asset retirement obligations that are being amortized over their respective lives ranging from three 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.

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 incurred 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 incurred costs and obligations as regulatory assets or liabilities if, based on regulatory orders or other available evidence, it is probable that the costs or obligations 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 and prior service cost.

Unbilled Revenues

OG&E recognizes revenue from electric sales when power is delivered to customers. 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. OG&E accrues an estimate of the revenues for electric sales delivered since the latest billings. 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, 2015, 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, 2015 and 2014, Accrued Unbilled Revenues were $53.5 million and $55.5 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, 2015, if the provision rate were to increase or decrease by 10 percent, this would cause a change in the uncollectible expense recognized of $0.1 million. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Consolidated Balance Sheets and is included in the Other Operation and Maintenance Expense on the Consolidated Statements of Income. The allowance for uncollectible accounts receivable was $1.4 million and $1.6 million at December 31, 2015 and 2014, 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 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 available information, 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 14 and 15 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 numerous stringent and complex Federal, state and local laws and regulations governing environmental protection. These laws and regulations can change, restrict or otherwise impact OG&E's business activities in many ways including the handling or disposal of waste material, future construction activities to avoid or mitigate harm to threatened or endangered species and requiring the installation and operation of emissions 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. OG&E believes that its operations are in substantial compliance with current Federal, state and local environmental standards.

Environmental regulation can increase the cost of planning, design, initial installation and operation of OG&E's 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 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 expenditures necessary to comply with the environmental laws and regulations discussed below will qualify as part of a pre-approval plan to handle state and Federally mandated environmental upgrades which will be recoverable in Oklahoma from OG&E's retail customers under House Bill 1910, which was enacted into law in May 2005.

It is estimated that OG&E's total expenditures to comply with environmental laws, regulations and requirements for 2016 will be $195.9 million, of which $178.3 million is for capital expenditures. It is estimated that OG&E's total expenditures to comply with environmental laws, regulations and requirements for 2017 will be approximately $166.7 million, of which $148.7 million is for capital expenditures. The amounts for OG&E above include capital expenditures for low NO_X burners and dry scrubbers.

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

The EPA's 2005 regional haze rule is intended to protect visibility in certain national parks and wilderness areas throughout the United States that may be impacted by air pollutant emissions.

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 NO_X and SO_2 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 NO_X emissions at all of the subject units should be the installation of low NO_X burners with overfired air (flue gas recirculation was also required on two of the units) and set forth associated NO_X emission rates and limits.

On December 28, 2011, the EPA issued a final rule in which it rejected the SO_2 portion of the Oklahoma SIP and issued a FIP in its place. OG&E and the State of Oklahoma's subsequent appeal of the FIP with the Tenth Circuit of Appeals and the U.S. Supreme Court ended on May 27, 2014 when the Supreme Court denied OG&E's Petition for Certiorari, upholding the EPA's FIP for SO_2. The FIP compliance date is now January 4, 2019.

On December 9, 2015, the EPA released a final rule partially disapproving the revisions to the 2010 Oklahoma SIP for Regional Haze and promulgated FIPs in their place for Oklahoma and Texas. The EPA disapproved portions of the Oklahoma SIP related to the establishment of Reasonable Progress Goals for the Class I area located within the state and promulgated revised Reasonable Progress Goals based on the FIP implementation in Texas. As a result, no further requirements are required in Oklahoma to meet the 2018 Reasonable Progress Goals for Oklahoma.

On August 6, 2014, OG&E filed an application with the OCC for approval of its plan to comply with the EPA's MATS and Regional Haze FIP while serving the best long-term interests of customers in light of future environmental uncertainties. The application seeks approval of the environmental compliance plan and for a recovery mechanism for the associated costs. The ECP includes installing dry scrubbers at Sooner Units 1 and 2 and the conversion of Muskogee Units 4 and 5 to natural gas. The application also asked the OCC to predetermine the prudence of replacing OG&E's soon-to-be retired Mustang steam turbines in late 2017 with 400 MWs of new, efficient combustion turbines at the Mustang site in 2018 and 2019 and approval for a recovery mechanism for the associated costs. OG&E estimates the total capital cost associated with its environmental compliance plan included in this application to be approximately $1.1 billion. The OCC hearing on OG&E's application before an ALJ began on March 3, 2015 and concluded on April 8, 2015. Multiple parties advocating a variety of positions intervened in the proceeding.

On June 8, 2015, the ALJ issued his report on OG&E's application. While the ALJ in his report agreed that the installation of dry scrubbers at Sooner Units 1 and 2 and the conversion of Muskogee Units 4 and 5 to natural gas pursuant to OG&E's ECP is the best approach, the ALJ's report included several recommendations. OG&E filed exceptions to the ALJ's report and on July 21, 2015, Commissioner Bob Anthony issued his deliberation statement that was consistent with many parts of the ALJ's report, including the ALJ's support of OG&E's ECP, the ALJ's recommendation to pre-approve certain estimated costs of the environmental recovery plan, and the ALJ's recommendation to defer all other cost recovery issues until the next general rate case.

On December 2, 2015, OG&E received an order from the OCC denying, by a two to one vote, its plan to comply with the environmental mandates of the Federal Clean Air Act, Regional Haze and MATS. The OCC also denied OG&E's request for pre-approval of its Mustang Modernization Plan, revised depreciation rates for both the retirement of the Mustang units and the replacement combustion turbines and pre-approval of early retirement and replacement of generating units at its Mustang site, including cost recovery through a rider.

On December 11, 2015, OG&E filed a motion requesting modification of the OCC order for the purposes of approving only the ECP. OG&E did not seek modification to any other provisions of the OCC order, including cost recovery. OG&E also agreed that it would not implement a rider for recovery of the costs of the ECP until and unless authorized by the OCC in a subsequent proceeding.

On December 23, 2015, the OCC rejected, by a two to one vote, a proposal by Commissioner Dana Murphy to grant OG&E's December 11, 2015 motion.

On February 12, 2016, OG&E filed an application requesting the OCC to issue an order approving the installation of dry scrubbers at the Sooner facility, on or before May 2, 2016. The application states that if the application is not approved by May 2, 2016, OG&E will decide at that time whether to cancel the dry scrubber equipment and installation contracts and make plans to convert the Sooner coal units to natural gas. As of December 31, 2015, OG&E had incurred $94.8 million of construction work in progress on the dry scrubbers. OG&E estimates another $35.0 million of in-process expenditures will be incurred prior to May 1, 2016. Additionally, if the request is not approved, OG&E expects to seek recovery in subsequent proceedings for the expenditures incurred for the dry scrubber project and reasonable stranded costs associated with the discontinuance of the Sooner coal units.

Cross-State Air Pollution Rule

In August 2011, the EPA finalized its CSAPR that required 27 states in the eastern half of the United States to reduce power plant emissions that contribute to ozone and particulate matter pollution in other states. In December 2011, the EPA published a supplemental CSAPR, which would make six additional states, including Oklahoma, subject to the CSAPR for NO_X emissions during the ozone-season from May 1 through September 30. Under the rule, OG&E would have been required to reduce ozone-season NO_X emissions from its electrical generating units within the state beginning in 2012. In response to legal challenges of the final rule 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 Court of Appeals vacated the CSAPR and ordered the EPA to promulgate a replacement rule. On April 29, 2014, the U.S. Supreme Court reversed the decision by the Court of Appeals. On October 23, 2014, the Court of Appeals for the District of Columbia Circuit granted the EPA's request that the court lift the stay of the CSAPR. The EPA subsequently clarified that compliance with the CSAPR would begin in 2015 using the amount of allowances originally scheduled to be available in 2012. As of December 31, 2015, OG&E has installed five low NO_X burner systems on two Muskogee units, two Sooner units and one Seminole unit and is in compliance with the final rule. In the meantime, the petitions for review of the supplemental rule remain pending before the D.C. Circuit Court of Appeals for consideration of issues that are not addressed by the Supreme Court's decision.

On December 3, 2015, the EPA proposed an update to CSAPR finding that ozone-season NO_X emissions in 23 eastern states including Oklahoma affect the ability of downwind states to attain and maintain ozone standards and proposing to issue FIPs to update the existing NO_X ozone-season emission budgets for electrical generating units. The proposed rule reduces OG&E's NO_X emissions requirements under the current CSAPR by 25 percent. Compliance is proposed to begin in May 2017. OG&E continues to evaluate what additional measures, if any, will be needed for compliance with the new rule.

Hazardous Air Pollutants Emission Standards

On February 16, 2012, the EPA published the final MATS rule regulating the emissions of certain hazardous air pollutants from electric generating units, which became effective April 16, 2012. The final rule uses a numerical standard to establish limits for particulate matter (as a surrogate for toxic metals), hydrogen chloride and mercury emissions from coal-fired boilers. Compliance was required within three years of the rule's effective date. Based on OG&E's request for a one-year extension, the deadline for compliance was extended to April 16, 2016. To comply with this rule, OG&E utilized activated carbon injections at each of its five coal-fired units during 2015.

The final MATS rule was appealed by several parties, but OG&E was not a party to the appeals. After withstanding judicial scrutiny at the District of Columbia Circuit Court of Appeals, the MATS rule was challenged at the U.S. Supreme Court. On June 29, 2015, the U.S. Supreme Court found that the EPA should have considered the compliance costs imposed on utilities at the first stage of the EPA's regulatory analysis. The U.S. Supreme Court did not vacate the rule, but reversed the D.C. Circuit's decision and remanded to the D.C. Circuit for further proceedings. The MATS rule currently remains in effect and OG&E is still required to meet the April 2016 compliance deadline.

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.

On July 8, 2013, the U.S. Department of Justice filed a complaint against OG&E in United States District Court for the Western District of Oklahoma 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 intervened in this proceeding. On August 30, 2013, the government filed a Motion for Summary Judgment and on September 6, 2013, OG&E filed a Motion to Dismiss the case. On January 15, 2015, U.S. District Judge Timothy DeGuisti dismissed the complaints filed by the EPA and the Sierra Club. The Court held that it lacked subject matter jurisdiction over plaintiffs' claims because plaintiffs failed to present an actual "case or controversy" as required by Article III of the Constitution. The court also ruled in the alternative that, even if plaintiffs had presented a case or controversy, it would have nonetheless "decline[d] to exercise jurisdiction." The EPA and the Sierra Club did not file an appeal of the Court's ruling.

On August 12, 2013, the Sierra Club filed a separate complaint against OG&E in the United States District Court for the Eastern District of Oklahoma alleging that OG&E projects at Muskogee Unit 6 in 2008 were made without obtaining a prevention of significant deterioration permit and that the plant had exceeded emissions limits for opacity and particulate matter. The Sierra Club seeks a permanent injunction preventing OG&E from operating the Muskogee generating plant. On March 4, 2014, the Eastern District dismissed the prevention of significant deterioration permit claim based on the statute of limitations, but allowed the opacity and particulate matter claims to proceed. To obtain the right to appeal this decision, the Sierra Club subsequently withdrew a Notice of Intent to Sue for additional Clean Air Act violations and asked the Eastern District to dismiss its remaining claims with prejudice. On August 27, 2014, the Eastern District granted the Sierra Club's request. The Sierra Club has filed a Notice of Appeal with the 10th Circuit where oral argument was held on March 18, 2015.

At this time, OG&E continues to believe that it has acted in compliance with the Federal Clean Air Act, and OG&E expects to vigorously defend against the claims that have been asserted. If OG&E does not prevail in the remainder of the proceedings, the EPA and the Sierra Club could seek to require OG&E to install additional pollution control equipment, including dry scrubbers, baghouses and selective catalytic reduction systems with capital costs in excess of $1.1 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. Due to the uncertain and preliminary nature of this litigation, OG&E cannot provide a range of reasonably possible loss in this case.

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 2015, no areas of Oklahoma had been designated as non-attainment 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.

In August of 2013, the Sierra Club and the Natural Resources Defense Council filed a complaint under the citizen suit provision of the Clean Air Act based on the EPA's failure to promulgate and publish designations for the 2010 revised primary SO2 NAAQS. On March 2, 2015, the U.S. District Court for the Northern District of California issued an order granting the EPA and the Sierra Club's joint motion to approve and enter a consent decree that set forth mandatory deadlines for the EPA to issue designations for all areas of the country that remained undesignated. On September 18, 2015 the Oklahoma Department of Environmental Quality reported to the EPA that no areas in Oklahoma should be designated as non-attainment for the 2010 SO2 standard. This non-attainment designation is subject to the EPA's approval. In a letter dated February 11, 2016, EPA Region 6 notified Oklahoma of their intent to designate part of Muskogee County in which OG&E’s Muskogee Power Plant is located, as non-attainment for the 2010 SO2 NAAQS. EPA is expected to finalize this designation in July, 2016 following public comment. This could require additional controls scrubbers on the affected units. On August 21, 2015, EPA finalized a data requirements rule for implementing the 2010 SO2 standard requiring air agencies to characterize air quality around sources that emit 2,000 tons per year or more of SO2 via air quality modeling or ambient air monitoring. In July 2016, air agencies will be required to identify either ambient monitoring or air quality modeling as a method for characterizing air quality for 2,000 tons per year or larger sources. At this time, OG&E cannot determine with any certainty whether this determination will cause a material impact to the Company's financial results.

On September 30, 2015 the EPA finalized a new ambient standard for ozone at 70 ppb which is more stringent than the current standard of 75 ppb, set in 2008. States must submit non-attainment designations as appropriate based on existing ambient data before October 2016 for the EPA’s approval. Compliance with the new standard begins in 2020 or later depending on the degree of the area’s non-attainment designation. All areas in Oklahoma currently meet the new standard.

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.

Clean Power Plan

On October 23, 2015, the EPA published the final Clean Power Plan that established standards of performance for CO_2 emissions from existing fossil-fuel-fired power plants along with state-specific CO_2 reduction standards expressed as both rate-based (lbs/MWh) and mass-based (tons/yr) goals. The 2030 rate-based reduction requirement for all existing generating units in Oklahoma has decreased from a proposed 43 percent reduction to 32 percent in the final rule. The mass-based approach for existing units calls for a 24 percent reduction by 2030 in Oklahoma. The Clean Power Plan requires that states submit to the EPA plans for achieving the state-specific CO_2 reduction goals by September 6, 2016 or submit an extension request for up to two years. The compliance period was to begin in 2022, and emission reductions were to be phased in by 2030. The EPA also proposed a federal compliance plan to implement the Clean Power Plan in the event that an approvable state plan was not submitted to the EPA by the required deadline.

A number of states have filed lawsuits against the Clean Power Plan. On February 9, 2016, the U.S. Supreme Court issued orders staying implementation of the Clean Power Plan pending resolution of challenges to the rule. The Company is unable to determine what impact the lawsuits will ultimately have on the Clean Power Plan or what impact the stay in implementation will have; however, if the Clean Power Plan survives judicial review and is implemented as written, it 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. Significant uncertainties would remain with regards to potential implementation in Oklahoma (and the federal plan that would be imposed by the EPA for states that do not submit approvable plans), including whether states would elect an emissions standards approach versus a state measures approach, whether and what type of emissions trading would be allowed, and available cost mitigation options. Due to the pending litigation and the uncertainties in the state approaches, the ultimate timing and impact of these standards on our operations cannot be determined with certainty at this time.

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 CO_2, sulfur hexafluoride and methane, and whether these emissions are contributing to the warming of the earth's atmosphere. In December 2015, as part of the 21st Conference of the Parties to the United Nations Framework Convention on Climate Change, the United States committed to reduce economy wide emissions by 26 percent to 28 percent below 2005 emission levels. This multinational agreement will be open for signing on April 22, 2016 and will require countries to review and "represent a progression" every five years beginning in 2020. The agreement could result in future additional emissions reductions in the United States, however, it is not possible to determine what the international legal standards for greenhouse gas emissions will be in the future and the extent to which commitments under the December 2015 Paris Agreement will be implemented through the Clean Air Act, other than existing statutes and new legislation.

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.

If legislation or regulations are passed at the Federal or state levels in the future requiring mandatory reductions of CO_2 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 CO_2 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 CO_2 emissions from generating units subject to the Federal Acid Rain Program. OG&E has submitted the reports required by the applicable reporting rules.

Nonetheless, OG&E’s current business strategy will result in a reduced carbon emissions rate compared to current levels. As discussed in “Pending Regulatory Matters”, OG&E has filed an application with the OCC for approval of its plan to comply with the EPA’s MATS and Regional Haze FIP by converting two coal-fired generating units at Muskogee Station to natural gas, among other measures. OG&E’s deployment of Smart Grid technology helps to reduce the peak load demand. OG&E also seeks to utilize renewable energy sources that do not emit greenhouse gases. OG&E's service territory borders one of the nation's best wind resource areas. OG&E has leveraged its geographic position to develop renewable energy resources and completed transmission investments 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 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.

EPA Startup, Shutdown, and Malfunction Policy

On May 22, 2015, the EPA issued a final rule to address the outdated provisions in the SIP of 36 states, including Oklahoma, regarding the treatment of emissions that occur during startup, shutdown and malfunction operations. The final rule clarifies the EPA's Startup, Shutdown and Malfunction Policy to assure consistency with the Clean Air Act and other recent court decisions. The Oklahoma Department of Environmental Quality is in the process of developing a SIP to comply with this rule, which is to be submitted to the EPA before November 2016. Although the extent of impact is not known, this rule will impact certain OG&E units.

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, wind or pipeline projects, could be restricted or delayed, or the Company could be required to implement expensive mitigation measures.

In 2014, the Company enrolled in the Western Association of Fish and Wildlife Agencies range-wide conservation plan which consists of industry-specific conservation practices that apply to projects and activities in the impacted area. The range-wide conservation plan was approved by the U.S. Fish and Wildlife Service and incorporated as part of the agency's final decision on March 27, 2014 to list the lesser prairie chicken as a threatened species. On September 1, 2015, the U.S. District Court Western District of Texas vacated federal protections for the lesser prairie chicken based on the U.S. Fish and Wildlife Service's failure to thoroughly consider the active conservation efforts in making the listing decision.

Air Quality Control System

On September 10, 2014, OG&E executed a contract for the design, engineering and fabrication of two circulating dry scrubber systems to be installed at Sooner Units 1 and 2. OG&E entered into an agreement on February 9, 2015, to install the dry scrubber systems. The dry scrubbers are part of OG&E's ECP and scheduled to be completed by 2019. More detail regarding the ECP can be found under the "Pending Regulatory Matters" section of "Notes to Consolidated Financial Statements" of Part II, Item 8 of this Form 10-K.

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.

On December 19, 2014, the EPA finalized a rule under the Federal Resource Conservation and Recovery Act for the handling and disposal of coal combustion residuals or coal ash. The final rule regulates coal ash as a solid waste rather than a hazardous waste, which would have made the management of coal ash more costly. OG&E has evaluated the potential impacts of the final rule on our ash ponds and has set up a reserve based on a reasonable estimate.

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 2015, the Company obtained refunds of $2.3 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 comparable 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 EPA issued a final rule on May 19, 2014 to implement Section 316(b) of the Federal Clean Water Act, which requires that power plant cooling water intake structure location, design, construction and capacity reflect the best available technology for minimizing their adverse environmental impact via the impingement and entrainment of aquatic organisms. The EPA issued a final rule on May 19, 2014. OG&E submitted compliance plans to the state in April 2015. OG&E expects to be able to provide a reasonable estimate of any material costs associated with the rule's implementation.

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.

For a further discussion regarding contingencies relating to environmental laws and regulations, see Note 14 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)*	2016	2017	2018	2019	2020	Thereafter	Total	12/31/15 Fair Value
Fixed-rate debt (A)								
Principal amount	$ 110.2	$ 125.2	$ 250.1	$ 250.1	$ 0.1	$ 1,794.5	$ 2,530.2	$ 2,763.8
Weighted-average interest rate	5.15%	6.50%	6.35%	8.25%	4.34%	5.20%	5.68%	
Variable-rate debt (B)								
Principal amount	$ —	$ 100.0	$ —	$ —	$ —	$ 135.4	$ 235.4	$ 235.3
Weighted-average interest rate	—%	0.93%	—%	—%	—%	0.05%	0.43%	

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

(B) A hypothetical change of 100 basis points in the underlying variable interest rate incurred by the Company would change interest expense by $2.4 million annually through 2017 and $1.4 million thereafter.

Item 8. Financial Statements and Supplementary Data.

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

Year ended December 31 *(In millions except per share data)*	**2015**	2014	2013
OPERATING REVENUES			
Electric Utility	**$ 2,196.9**	$ 2,453.1	$ 2,259.7
Natural Gas Midstream Operations (Note 1)	**—**	—	608.0
Total operating revenues	**2,196.9**	2,453.1	2,867.7
COST OF SALES			
Electric Utility	**865.0**	1,106.6	950.0
Natural Gas Midstream Operations (Note 1)	**—**	—	478.9
Total cost of sales	**865.0**	1,106.6	1,428.9
OPERATING EXPENSES			
Other operation and maintenance	**451.6**	439.6	489.2
Depreciation and amortization	**307.9**	281.4	297.3
Taxes other than income	**91.2**	88.7	98.8
Total operating expenses	**850.7**	809.7	885.3
OPERATING INCOME	**481.2**	536.8	553.5
OTHER INCOME (EXPENSE)			
Equity in earnings of unconsolidated affiliates (Note 1)	**15.5**	172.6	101.9
Allowance for equity funds used during construction	**8.3**	4.2	6.6
Other income	**27.0**	17.8	31.8
Other expense	**(14.3)**	(14.4)	(22.2)
Net other income	**36.5**	180.2	118.1
INTEREST EXPENSE			
Interest on long-term debt	**147.8**	144.6	145.6
Allowance for borrowed funds used during construction	**(4.2)**	(2.4)	(3.4)
Interest on short-term debt and other interest charges	**5.4**	6.2	5.3
Interest expense	**149.0**	148.4	147.5
INCOME BEFORE TAXES	**368.7**	568.6	524.1
INCOME TAX EXPENSE	**97.4**	172.8	130.3
NET INCOME	**271.3**	395.8	393.8
Less: Net income attributable to noncontrolling interests	**—**	—	6.2
NET INCOME ATTRIBUTABLE TO OGE ENERGY	**$ 271.3**	$ 395.8	$ 387.6
BASIC AVERAGE COMMON SHARES OUTSTANDING	**199.6**	199.2	198.2
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**199.6**	199.9	199.4
BASIC EARNINGS PER AVERAGE COMMON SHARE ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS	**$ 1.36**	$ 1.99	$ 1.96
DILUTED EARNINGS PER AVERAGE COMMON SHARE ATTRIBUTABLE TO OGE ENERGY COMMON SHAREHOLDERS	**$ 1.36**	$ 1.98	$ 1.94
DIVIDENDS DECLARED PER COMMON SHARE	**$ 1.05000**	$ 0.95000	$ 0.85125

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)*	**2015**	2014	2013
Net income	**$ 271.3**	$ 395.8	$ 393.8
Other comprehensive income (loss), net of tax			
Pension Plan and Restoration of Retirement Income Plan:			
Amortization of deferred net loss, net of tax of $2.2, $1.2, and $2.4, respectively	**2.5**	1.8	3.7
Net gain (loss) arising during the period, net of tax of ($5.8), ($7.0), and $7.8, respectively	**(9.5)**	(11.1)	12.4
Settlement (curtailment) cost, net of tax of $2.9, ($0.1) and $1.9, respectively	**4.6**	(0.1)	3.0
Postretirement Benefit Plans:			
Amortization of deferred net loss, net of tax of $0.8, $0.5, and $1.3, respectively	**1.2**	0.9	2.0
Net gain (loss) arising during the period, net of tax of $5.6, ($1.9), and $4.4, respectively	**9.3**	(3.1)	6.9
Amortization of prior service cost, net of tax of ($1.1), ($1.1), and ($1.1), respectively	**(1.8)**	(1.8)	(1.8)
Deferred commodity contracts hedging losses reclassified in net income, net of tax of $0, $0, and $0.4, respectively	**—**	—	0.6
Amortization of deferred interest rate swap hedging losses, net of tax of $0, $0.1, and $0.1, respectively	**—**	0.2	0.3
Other comprehensive income (loss), net of tax	**6.3**	(13.2)	27.1
Comprehensive income	**277.6**	382.6	420.9
Less: Comprehensive income attributable to noncontrolling interests	**—**	—	6.3
Less: Deconsolidation of Enogex Holdings	**—**	—	6.1
Total comprehensive income attributable to OGE Energy	**$ 277.6**	$ 382.6	$ 408.5

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)*	**2015**	2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	**$ 271.3**	$ 395.8	$ 393.8
Adjustments to reconcile net income to net cash provided from operating activities			
Depreciation and amortization	**307.9**	281.4	298.6
Deferred income taxes and investment tax credits	**102.6**	177.3	125.9
Equity in earnings of unconsolidated affiliates	**(15.5)**	(172.6)	(101.9)
Distributions from unconsolidated affiliates	**94.1**	143.7	51.7
Allowance for equity funds used during construction	**(8.3)**	(4.2)	(6.6)
Gain on disposition of assets	**(0.2)**	(0.2)	(8.6)
Stock-based compensation	**5.9**	(2.7)	(3.5)
Regulatory assets	**(9.1)**	4.5	26.7
Regulatory liabilities	**(27.5)**	(4.4)	(32.5)
Other assets	**10.6**	(16.3)	1.3
Other liabilities	**8.6**	29.6	(7.0)
Change in certain current assets and liabilities			
Accounts receivable, net	**15.7**	(9.4)	(34.0)
Accounts receivable - unconsolidated affiliates	**3.9**	6.8	3.7
Accrued unbilled revenues	**2.0**	3.2	(1.3)
Income taxes receivable	**(1.2)**	(10.4)	1.6
Fuel, materials and supplies inventories	**(56.5)**	20.4	5.1
Fuel clause under recoveries	**68.3**	(42.1)	(26.2)
Other current assets	**(17.2)**	(2.6)	(4.4)
Accounts payable	**30.9**	(64.0)	56.9
Fuel clause over recoveries	**61.3**	(0.4)	(108.8)
Other current liabilities	**17.8**	(11.8)	(7.3)
Net Cash Provided from Operating Activities	**865.4**	721.6	623.2
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures (less allowance for equity funds used during construction)	**(547.8)**	(569.3)	(990.6)
Return of capital - equity method investments	**45.2**	9.5	—
Proceeds from sale of assets	**2.5**	0.7	36.3
Investment in unconsolidated affiliates	**—**	—	(2.7)
Net Cash Used in Investing Activities	**(500.1)**	(559.1)	(957.0)
CASH FLOWS FROM FINANCING ACTIVITIES			
Proceeds from long-term debt	**—**	588.9	247.4
Issuance of common stock	**7.2**	13.2	14.2
Dividends paid on common stock	**(204.6)**	(184.1)	(165.5)
Payment of long-term debt	**(0.2)**	(240.2)	(0.1)
(Decrease) increase in short-term debt	**(98.0)**	(341.6)	8.7
Changes in advances with unconsolidated affiliates	**—**	—	129.6
Contributions from noncontrolling interest partners	**—**	—	107.0
Distributions to noncontrolling interest partners	**—**	—	(2.5)
Net Cash (Used in) Provided from Financing Activities	**(295.6)**	(163.8)	338.8
NET CHANGE IN CASH AND CASH EQUIVALENTS	**69.7**	(1.3)	5.0
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**5.5**	6.8	1.8
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 75.2**	$ 5.5	$ 6.8

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

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS

December 31 *(In millions)*	**2015**	2014
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 75.2**	$ 5.5
Accounts receivable, less reserve of $1.4 and $1.6, respectively	**173.1**	188.8
Accounts receivable - unconsolidated affiliates	**1.7**	5.6
Accrued unbilled revenues	**53.5**	55.5
Income taxes receivable	**17.2**	16.0
Fuel inventories	**113.8**	58.5
Materials and supplies, at average cost	**80.1**	78.9
Deferred income taxes	**—**	191.4
Fuel clause under recoveries	**—**	68.3
Other	**55.6**	38.4
Total current assets	**570.2**	706.9
OTHER PROPERTY AND INVESTMENTS		
Investment in unconsolidated affiliates	**1,194.4**	1,318.2
Other	**70.7**	70.1
Total other property and investments	**1,265.1**	1,388.3
PROPERTY, PLANT AND EQUIPMENT		
In service	**10,318.3**	9,983.0
Construction work in progress	**278.5**	115.9
Total property, plant and equipment	**10,596.8**	10,098.9
Less accumulated depreciation	**3,274.4**	3,119.0
Net property, plant and equipment	**7,322.4**	6,979.9
DEFERRED CHARGES AND OTHER ASSETS		
Regulatory assets	**402.2**	410.4
Other	**37.5**	42.3
Total deferred charges and other assets	**439.7**	452.7
TOTAL ASSETS	**$ 9,597.4**	$ 9,527.8

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

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS (Continued)

December 31 *(In millions)*	**2015**	2014
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ —**	$ 98.0
Accounts payable	**262.5**	179.1
Dividends payable	**54.9**	49.9
Customer deposits	**77.0**	73.7
Accrued taxes	**45.9**	39.7
Accrued interest	**42.9**	43.0
Accrued compensation	**54.4**	38.2
Long-term debt due within one year	**110.0**	—
Fuel clause over recoveries	**61.3**	—
Other	**43.9**	51.7
Total current liabilities	**752.8**	573.3
LONG-TERM DEBT	**2,645.6**	2,755.3
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued benefit obligations	**299.9**	315.5
Deferred income taxes	**2,178.2**	2,268.3
Regulatory liabilities	**272.6**	263.0
Other	**122.3**	108.0
Total deferred credits and other liabilities	**2,873.0**	2,954.8
Total liabilities	**6,271.4**	6,283.4
COMMITMENTS AND CONTINGENCIES (NOTE 14)		
STOCKHOLDERS' EQUITY		
Common stockholders' equity	**1,101.3**	1,087.6
Retained earnings	**2,259.8**	2,198.2
Accumulated other comprehensive loss, net of tax	**(35.1)**	(41.4)
Total stockholders' equity	**3,326.0**	3,244.4
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 9,597.4**	$ 9,527.8

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 *(In millions)*			**2015**		2014
STOCKHOLDERS' EQUITY					
Common stock, par value $0.01 per share; authorized 450.0 shares; and outstanding 199.7 and 199.4 shares, respectively		**$**	**2.0**	$	2.0
Premium on common stock			**1,099.3**		1,085.6
Retained earnings			**2,259.8**		2,198.2
Accumulated other comprehensive loss, net of tax			**(35.1)**		(41.4)
Total stockholders' equity			**3,326.0**		3,244.4
LONG-TERM DEBT					
SERIES	DUE DATE				
Senior Notes - OGE Energy					
0.93%	Variable Senior Notes, Series Due November 24, 2017		**100.0**		100.0
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
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**		250.0
4.55%	Senior Notes, Series Due March 15, 2044		**250.0**		250.0
4.00%	Senior Notes, Series Due December 15, 2044		**250.0**		250.0
3.70%	Tinker Debt, Due August 31, 2062		**10.0**		10.2
Other Bonds - OG&E					
0.05% - 0.13%	Garfield Industrial Authority, January 1, 2025		**47.0**		47.0
0.06% - 0.19%	Muskogee Industrial Authority, January 1, 2025		**32.4**		32.4
0.05% - 0.14%	Muskogee Industrial Authority, June 1, 2027		**56.0**		56.0
Unamortized discount			**(9.8)**		(10.3)
Total long-term debt			**2,755.6**		2,755.3
Less long-term debt due within one year			**(110.0)**		—
Total long-term debt (excluding debt due within one year)			**2,645.6**		2,755.3
Total Capitalization (including long-term debt due within one year)		**$**	**6,081.6**	$	5,999.7

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, 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, 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	—	(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
Net income	—	—	395.8	—	—	—	395.8
Other comprehensive income, net of tax	—	—	—	(13.2)	—	—	(13.2)
Dividends declared on common stock	—	—	(189.3)	—	—	—	(189.3)
Issuance of common stock	—	13.2	—	—	—	—	13.2
Stock-based compensation	—	0.8	—	—	—	—	0.8
Balance at December 31, 2014	$ 2.0	$ 1,085.6	$ 2,198.2	$ (41.4)	$ —	$ —	$ 3,244.4
Net income	**—**	**—**	**271.3**	**—**	**—**	**—**	**271.3**
Other comprehensive income, net of tax	**—**	**—**	**—**	**6.3**	**—**	**—**	**6.3**
Dividends declared on common stock	**—**	**—**	**(209.7)**	**—**	**—**	**—**	**(209.7)**
Issuance of common stock	**—**	**7.2**	**—**	**—**	**—**	**—**	**7.2**
Stock-based compensation	**—**	**6.5**	**—**	**—**	**—**	**—**	**6.5**
Balance at December 31, 2015	**$ 2.0**	**$ 1,099.3**	**$ 2,259.8**	**$ (35.1)**	**$ —**	**$ —**	**$ 3,326.0**

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

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. The accounts of the Company and its wholly owned subsidiaries are included in the consolidated financial statements. All intercompany transactions and balances are eliminated in consolidation. The Company generally uses the equity method of accounting for investments where its ownership interest is between 20 percent and 50 percent and has the ability to exercise significant influence.

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, and is a wholly owned subsidiary of the Company. OG&E is the largest electric utility in Oklahoma and its franchised service territory includes Fort Smith, Arkansas and the surrounding communities. 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 currently represents the Company's investment in Enable through its wholly owned subsidiary OGE Holdings. 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 a crude oil gathering business in the Bakken shale formation, principally located in the Williston basin of North Dakota. Enable's natural gas transportation and storage assets extend from western Oklahoma and the Texas Panhandle to Alabama and from Louisiana to Illinois. For periods prior to the formation of Enable, the natural gas midstream operations segment reflected the consolidated results of Enogex Holdings. All significant intercompany transactions have been eliminated in consolidation.

Enable was formed effective May 1, 2013 by the Company, the ArcLight group and CenterPoint to own and operate the midstream businesses of the Company and CenterPoint. In the formation transaction, the Company and the 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's 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 management ownership. Based on the 50/50 management ownership, with neither company having control, effective May 1, 2013, the Company began accounting for its interest in Enable using the equity method of accounting.

In April 2014, Enable completed an initial public offering of 25,000,000 common units resulting in Enable becoming a publicly traded Master Limited Partnership. At December 31, 2015, the Company owned approximately 111.0 million limited partner units, or 26.3 percent, of which 68.2 million limited partner units were subordinated.

On January 22, 2016, Enable announced a quarterly dividend distribution of $0.31800 per unit on its outstanding common and subordinated units, which is unchanged from the previous quarter. Based on current commodity prices, Enable has seen changes in producer activity that have negatively impacted Enable's operations and financial position and could see additional changes in producer activity that may negatively impact Enable's operations and affect its future distribution rates. If cash distributions to Enable’s unitholders exceed $0.330625 per unit in any quarter, the general partner will receive increasing percentages, up to 50 percent, of the cash Enable distributes in excess of that amount. OGE Holdings is entitled to 60 percent of those “incentive distributions.” In certain circumstances, the general partner has the right to reset the minimum quarterly distribution and the target distribution levels at which the incentive distributions receive increasing percentages to higher levels based on Enable’s cash distributions at the time of the exercise of this reset election.

The Company charges operating costs to OG&E and Enable based on several factors. Operating costs directly related to OG&E and Enable are assigned as such. Operating costs incurred for the benefit of OG&E and Enable are allocated 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. The Company adopted this method in January 1996 as a result of a recommendation by the OCC Staff. The Company believes this method provides a reasonable basis for allocating common expenses.

Accounting Records

The accounting records of OG&E are maintained in accordance with the Uniform System of Accounts prescribed by the FERC and adopted by the OCC and the APSC. Additionally, OG&E, as a regulated utility, is subject to accounting principles for certain types of rate-regulated activities, which provide that certain incurred 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.

Certain prior year amounts have been reclassified to conform with the current year presentation.

OG&E records certain incurred costs and obligations as regulatory assets or liabilities if, based on regulatory orders or other available evidence, it is probable that the costs or obligations 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)*	**2015**	2014
Regulatory Assets		
Current		
Oklahoma demand program rider under recovery (A)	**$ 36.6**	$ 19.7
Fuel clause under recoveries	**—**	68.3
Other (A)(B)	**9.9**	10.2
Total Current Regulatory Assets	**$ 46.5**	$ 98.2
Non-Current		
Benefit obligations regulatory asset	**$ 242.2**	$ 261.1
Income taxes recoverable from customers, net	**56.7**	56.1
Smart Grid	**43.6**	43.9
Deferred storm expenses	**27.6**	17.5
Unamortized loss on reacquired debt	**14.8**	16.1
Other (B)	**17.3**	15.7
Total Non-Current Regulatory Assets	**$ 402.2**	$ 410.4
Regulatory Liabilities		
Current		
Fuel clause over recoveries	**$ 61.3**	$ —
Crossroads wind farm rider over recovery (C)	**2.9**	10.3
Smart Grid rider over recovery (C)	**2.0**	12.5
Other (C)	**2.6**	1.6
Total Current Regulatory Liabilities	**$ 68.8**	$ 24.4
Non-Current		
Accrued removal obligations, net	**$ 254.9**	$ 248.1
Pension tracker	**17.7**	14.9
Total Non-Current Regulatory Liabilities	**$ 272.6**	$ 263.0

(A) Included in Other Current Assets on the Consolidated Balance Sheets.
(B) Prior year amount of $1.1 million reclassified from Non-Current Other assets to Current Other assets.
(C) Included in Other Current Liabilities on the Consolidated Balance Sheets.

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

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 allowed 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.

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 and prior service cost. 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)*	**2015**	2014
Pension Plan and Restoration of Retirement Income Plan		
Net loss	**$ 214.1**	$ 196.7
Prior service cost	**—**	0.6
Postretirement Benefit Plans		
Net loss	**34.2**	83.6
Prior service cost	**(6.1)**	(19.8)
Total	**$ 242.2**	$ 261.1

The following amounts in the benefit obligations regulatory asset at December 31, 2015 are expected to be recognized as components of net periodic benefit cost in 2016:

(In millions)	
Pension Plan and Restoration of Retirement Income Plan	
Net loss	**$ 13.1**
Prior service cost	**—**
Postretirement Benefit Plans	
Net loss	**2.0**
Prior service cost	**6.1**
Total	**$ 21.2**

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 defers annual Oklahoma storm-related operation and maintenance expenses in excess of $2.7 million and includes in expense any Oklahoma storm-related operation and maintenance expenses up to $2.7 million. OG&E expects to recover the amounts deferred each year over a five-year period in accordance with historical practice.

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 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 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. 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 analog electric meters, which have been replaced by smart meters and were accumulated during the smart grid deployment and have been included in the Smart Grid asset in the regulatory assets and liabilities table above. These costs are expected to be recovered in base rates in OG&E's next general rate case.

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

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.

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, income taxes, contingency reserves, asset retirement obligations and depreciable lives of property, plant and equipment. For the electric utility segment, significant judgment is also exercised in the determination 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 investments 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

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 is a reduction to Accounts Receivable on the Consolidated Balance Sheets and is included in the Other Operation and Maintenance Expense on the Consolidated Statements of Income. The allowance for uncollectible accounts receivable was $1.4 million and $1.6 million at December 31, 2015 and 2014, respectively.

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 $119.3 million and $66.7 million at December 31, 2015 and 2014, respectively. Effective May 1, 2014, the gas storage services agreement with Enable was terminated. As a result of this contract termination, approximately 5.3 Bcf of cushion gas owned by OG&E and stored on the Enable system is being directed to OG&E's power plants over a five year period during peak time of June 1 to August 31 at a rate of 11,500 MMBtu/day for a total of 1.06 Bcf per year. In 2014, approximately $11.0 million of cushion gas was reclassified from Plant-in-Service to Other Deferred Assets and an additional $2.7 million was reclassified to current Fuel Inventories on the Balance Sheets. As of December 31, 2015, the balance of cushion gas in Other Deferred Assets is approximately $5.4 million.

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 Statements of Income.

December 31, 2015 *(In millions)*	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
McClain Plant (A)	**77%**	**$ 220.4**	**$ 62.8**	**$ 157.6**
Redbud Plant (A)(B)	**51%**	**$ 487.5**	**$ 101.2**	**$ 386.3**

(A) Construction work in progress was $1.6 million and $1.3 million for the McClain and Redbud Plants, respectively.
(B) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $39.8 million.

December 31, 2014 *(In millions)*	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
McClain Plant (A)	77%	$ 207.7	$ 46.6	$ 161.1
Redbud Plant (A)(B)	51%	$ 484.1	$ 81.8	$ 402.3

(A) Construction work in progress was $0.5 million and $0.4 million for the McClain and Redbud Plants, respectively.
(B) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $34.3 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, 2015 *(In millions)*	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
OGE Energy (holding company)			
Property, plant and equipment	**$ 139.0**	**$ 112.7**	**$ 26.3**
OGE Energy property, plant and equipment	**139.0**	**112.7**	**26.3**
OG&E			
Distribution assets	**3,728.8**	**1,152.8**	**2,576.0**
Electric generation assets (A)	**3,837.4**	**1,407.0**	**2,430.4**
Transmission assets (B)	**2,454.2**	**440.7**	**2,013.5**
Intangible plant	**81.0**	**38.0**	**43.0**
Other property and equipment	**356.4**	**123.2**	**233.2**
OG&E property, plant and equipment	**10,457.8**	**3,161.7**	**7,296.1**
Total property, plant and equipment	**$ 10,596.8**	**$ 3,274.4**	**$ 7,322.4**

(A) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $39.8 million.
(B) This amount includes a plant acquisition adjustment of $3.3 million and accumulated amortization of $0.5 million.

December 31, 2014 *(In millions)*	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
OGE Energy (holding company)			
Property, plant and equipment	$ 151.7	$ 113.3	$ 38.4
OGE Energy property, plant and equipment	151.7	113.3	38.4
OG&E			
Distribution assets	3,559.5	1,086.7	2,472.8
Electric generation assets (A)	3,620.1	1,345.1	2,275.0
Transmission assets (B)	2,370.0	417.8	1,952.2
Intangible plant	67.6	31.1	36.5
Other property and equipment	330.0	125.0	205.0
OG&E property, plant and equipment	9,947.2	3,005.7	6,941.5
Total property, plant and equipment	$ 10,098.9	$ 3,119.0	$ 6,979.9

(A) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $34.3 million.
(B) This amount includes a plant acquisition adjustment of $3.3 million and accumulated amortization of $0.4 million.

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

Year ended December 31 *(In millions)*	**2015**	2014
OGE Energy (holding company)	**$ 2.4**	$ 4.5
OG&E	**34.3**	33.6
Total	**$ 36.7**	$ 38.1

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

Year ended December 31 *(In millions)*	**2015**	2014	2013
OGE Energy (holding company)	**$ 2.0**	$ 4.3	$ 6.4
OG&E	**6.9**	5.2	4.0
Enogex LLC	**—**	—	0.8
Total	**$ 8.9**	$ 9.5	$ 11.2

Depreciation and Amortization

The provision for depreciation, which was 2.9 percent and 2.8 percent of the average depreciable utility plant for 2015 and 2014, respectively, 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 2016, the provision for depreciation is projected to be 2.9 percent of the average depreciable utility plant. Amortization of intangible assets is computed using the straight-line method. Of the remaining amortizable intangible plant balance at December 31, 2015, 96.4 percent will be amortized over nine years with the remaining 3.6 percent of the intangible plant balance at December 31, 2015 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 is being amortized over a 27 year life and $3.3 million for certain transmission substation facilities in OG&E's service territory, which are being amortized over a 37 to 59 year period.

Investment in Unconsolidated Affiliate

The Company'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, the Company 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. The Company accounts for its 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. The Company's maximum exposure to loss related to Enable is limited to the Company's equity investment in Enable as presented on the Company's Consolidated Balance Sheet at December 31, 2015. 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 Enable 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 Enable 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 three to 74 years.

The following table summarizes changes to the Company's asset retirement obligations during the years ended December 31, 2015 and 2014.

(In millions)	**2015**	2014
Balance at January 1	**$ 58.6**	$ 55.2
Accretion expense	**2.6**	2.5
Revisions in estimated cash flows (A)	**1.6**	1.7
Additions (B)	**0.9**	—
Liabilities settled (C)	**(0.4)**	(0.8)
Balance at December 31	**$ 63.3**	$ 58.6

(A) Assumptions changed related to the estimated cost of removal for one of OG&E's generating facilities.
(B) OG&E recorded an asset retirement obligation for $0.9 million for the ash pond located at the Muskogee generating facility.
(C) In 2015, asset retirement obligations were settled for the asbestos abatement at one of OG&E's generating facilities.

Allowance for Funds Used During Construction

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 8.1 percent, 6.9 percent and 8.3 percent for the years ended December 31, 2015, 2014 and 2013, respectively. The increase in the allowance for funds used during construction rates in 2015 was primarily due to short-term debt not being used to finance construction projects, which caused the equity portion of allowance for funds used during construction to increase.

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 recognizes revenue from electric sales when power is delivered to customers. 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. OG&E accrues an estimate of the revenues for electric sales delivered since the latest billings. 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.

The Company deconsolidated the results of operations for Enogex LLC as of May 1, 2013. Prior to this date, operating revenues for gathering, processing, transportation and storage services for Enogex LLC were 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 were reversed in the following month and customers were billed on actual volumes and contracted prices. Gas sales were calculated on current-month nominations and contracted prices. Operating revenues associated with the production of NGLs were estimated based on current-month estimated production and contracted prices. These amounts were reversed in the following month and the customers were billed on actual production and contracted prices.

Enogex LLC recognized revenue from natural gas gathering, processing, transportation and storage services to third parties as services were provided. Revenue associated with NGLs was recognized when the production was sold.

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

Enogex LLC engaged in asset management and hedging activities related to the purchase and sale of natural gas and NGLs. Contracts utilized in these activities generally included purchases and sales for physical delivery, over-the-counter forward swap and options contracts and exchange traded futures and options.

SPP Purchases and Sales

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. On March 1, 2014, the SPP implemented FERC-approved regional day ahead and real-time markets for energy and operating services, as well as associated transmission congestion rights. Collectively the three markets operate together under the global name, SPP Integrated Marketplace. OG&E represents owned and contracted generation assets and customer load in the SPP Integrated Marketplace for the sole benefit of its customers. OG&E has not participated in the SPP Integrated Marketplace for any speculative trading activities. OG&E records the SPP Integrated Marketplace transactions as sales or purchases per FERC Order 668, which requires that purchases and sales be recorded on a net basis for each settlement period of the SPP Integrated Marketplace. These results are reported as Operating Revenues or Cost of Goods Sold in its Consolidated Financial Statements. OG&E revenues, expenses, assets and liabilities may be adversely affected by changes in the organization, operating and regulation by the FERC or the SPP.

Fuel Adjustment Clauses

The actual cost of fuel used in electric generation and certain purchased power costs 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 in the Consolidated Statements of Income.

Accrued Vacation

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

Accumulated Other Comprehensive Income (Loss)

The following tables summarize changes in the components of accumulated other comprehensive loss attributable to OGE Energy during 2014 and 2015. All amounts below are presented net of tax.

	Pension Plan and Restoration of Retirement Income Plan			Postretirement Benefit Plans		
(In millions)	Net loss	Prior service cost	Settlement cost	Net loss	Prior service cost	Total
Balance at December 31, 2013	$ (27.4)	$ 0.1	$ —	$ (5.8)	$ 5.1	$ (28.0)
Other comprehensive income (loss) before reclassifications	(11.1)	—	—	(3.1)	—	(14.2)
Amounts reclassified from accumulated other comprehensive income (loss)	1.7	—	—	0.9	(1.8)	0.8
Net current period other comprehensive income (loss)	(9.4)	—	—	(2.2)	(1.8)	(13.4)
Balance at December 31, 2014	$ (36.8)	$ 0.1	$ —	$ (8.0)	$ 3.3	$ (41.4)
Other comprehensive income (loss) before reclassifications	**(9.5)**	**—**	**—**	**9.3**	**—**	**(0.2)**
Amounts reclassified from accumulated other comprehensive income (loss)	**2.5**	**—**	**4.6**	**1.2**	**(1.8)**	**6.5**
Net current period other comprehensive income (loss)	**(7.0)**	**—**	**4.6**	**10.5**	**(1.8)**	**6.3**
Balance at December 31, 2015	**$ (43.8)**	**$ 0.1**	**$ 4.6**	**$ 2.5**	**$ 1.5**	**$ (35.1)**

The following table summarizes significant amounts reclassified out of accumulated other comprehensive loss by the respective line items in net income during the years ended December 31, 2015 and 2014.

Details about Accumulated Other Comprehensive Income (Loss) Components	Amount Reclassified from Accumulated Other Comprehensive Income (Loss)		Affected Line Item in the Statement Where Net Income is Presented
	Year Ended December 31,		
(In millions)	**2015**	2014	
Losses on cash flow hedges			
Interest rate swap	**$ —**	$ (0.3)	Interest expense
	—	(0.3)	Total before tax
	—	(0.1)	Tax benefit
	$ —	$ (0.2)	Net of tax
Amortization of defined benefit pension and restoration of retirement income plan items			
Actuarial losses	**$ (4.7)**	$ (3.0)	(A)
(Settlement) curtailment cost	**(7.5)**	0.2	(A)
	(12.2)	(2.8)	Total before tax
	(5.1)	(1.1)	Tax benefit
	$ (7.1)	$ (1.7)	Net of tax
Amortization of postretirement benefit plan items			
Actuarial losses	**$ (2.0)**	$ (1.4)	(A)
Prior service cost	**2.9**	2.9	(A)
	0.9	1.5	Total before tax
	0.3	0.6	Tax expense
	$ 0.6	$ 0.9	Net of tax
Total reclassifications for the period	**$ (6.5)**	$ (1.0)	Net of tax

(A) These accumulated other comprehensive income (loss) components are included in the computation of net periodic benefit cost (see Note 12 for additional information).

The amounts in accumulated other comprehensive loss at December 31, 2015 that are expected to be recognized into earnings in 2016 are as follows:

(In millions)	
Pension Plan and Restoration of Retirement Income Plan	
Net loss	**$ (4.8)**
Postretirement Benefit Plans	
Net loss	**—**
Prior service cost	**(2.6)**
Total, net of tax	**$ (7.4)**

Environmental Costs

Accruals for environmental costs are recognized when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated. Costs are charged to expense or deferred as a regulatory asset based on expected recovery from customers in future rates, if they relate to the remediation of conditions caused by past operations or if they are not expected to mitigate or prevent contamination from future operations. Where environmental expenditures relate to facilities currently in use, such as pollution control equipment, the costs may be capitalized and depreciated over the future service periods. Estimated remediation costs are recorded at undiscounted amounts, independent of any insurance or rate recovery, based on prior experience, assessments and current technology. Accrued obligations are regularly adjusted as environmental assessments and estimates are revised, and remediation efforts proceed. For sites where OG&E 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 $10.0 million and $7.5 million in accrued environmental liabilities at December 31, 2015 and 2014, respectively, which are included in the asset retirement obligations table.

2. Accounting Pronouncements

Revenue from Contracts with Customers. In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers (Topic 606)". The new guidance was intended to be effective for fiscal years beginning after December 15, 2016. On July 9, 2015, the FASB decided to delay the effective date of the new revenue standard by one year. Reporting entities may choose to adopt the standard as of the original effective date. The deferral results in the new revenue standard being effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017. The standard permits the use of either the retrospective or cumulative effect transition method. The Company has yet to select a transition method or determine the impact on its consolidated financial statements, however, the impact is not expected to be material.

Consolidation. In February 2015, the FASB issued ASU 2015-02, "Consolidation (Topic 810)". The amendments in ASU 2015-02 affect reporting entities that are required to evaluate whether they should consolidate certain legal entities. The new standard modifies the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities along with eliminating the presumption that a general partner should consolidate a limited partnership. The new standard is effective for fiscal years beginning after December 15, 2015. The Company does not believe the new standard will result in the consolidation of any non-consolidated entities.

Simplifying the Presentation of Debt Issuance Costs. In April 2015, the FASB issued ASU 2015-03, "Interest - Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs". The amendments in ASU 2015-03 require that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability consistent with debt discounts. The amendments in this ASU are effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. The Company will reflect the impact of this ASU in the first quarter of 2016. The Company does not believe the new standard will have a material effect on its financial statements.

Intangibles-Goodwill and Other-Internal Use Software. In April 2015, the FASB issued ASU 2015-05, "Intangibles-Goodwill and Other-Internal Use Software (Subtopic 350-40)". The amendments in ASU 2015-05 provide guidance to customers about whether a cloud computing arrangement includes a software license. The absence of a software license requires accounting for the arrangement as a service contract. For public business entities, the amendments in this ASU are effective for financial statements issued for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years. The Company will reflect the impact of this ASU in the first quarter of 2016 and does not believe the new standard will have a material effect on its financial statements.

Fair Value Measurement. In May 2015, the FASB issued ASU 2015-07 “Fair Value Measurement (Topic 820): Disclosures for Investments in Certain Entities That Calculate Net Asset Value per Share (or Its Equivalent)” (ASU 2015-07). ASU 2015-07 removes the requirement to categorize within the fair value hierarchy all investments for which fair value is measured using the net asset value per share practical expedient. It also eliminates certain disclosures for investments measured at fair value using the net asset value per share practical expedient. The guidance is effective for fiscal years beginning after December 15, 2015, and interim periods within those fiscal years and requires retrospective presentation. Adoption of this new standard is applicable to the Company's benefit plans and will not impact the Company's Pension Plan's Statement of Net Assets Available for Benefits or Statement of Changes in Net Assets Available for Benefits.

Income Taxes. In November 2015, the FASB issued ASU 2015-17 “Income Taxes (Topic 740)”. The amendments in ASU 2015-17 require that deferred tax liabilities and assets be classified as non-current in the statements of financial position. The classification change for all deferred taxes as non-current simplifies entities' processes as it eliminates the need to separately identify the net current and net non-current deferred tax asset or liability. For public business entities, the amendments in this ASU are effective for financial statements issued for annual periods beginning after December 15, 2016, and interim periods within those annual periods. Because ASU 2015-17 simplifies balance sheet presentation, the Company has elected to prospectively adopt the accounting standard for 2015.

3. Investment in Unconsolidated Affiliate and Related Party Transactions

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

Pursuant to the Master Formation Agreement, the Company 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. 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.

The general partner of Enable is equally controlled by CenterPoint and OGE Energy, who each have 50 percent management ownership. Based on the 50/50 management ownership, with neither company having control, effective May 1, 2013, the Company deconsolidated its interest in Enogex Holdings and began accounting for its interest in Enable using the equity method of accounting.

In April 2014, Enable completed an initial public offering of 25,000,000 common units resulting in Enable becoming a publicly traded Master Limited Partnership. At December 31, 2015, the Company owned approximately 111.0 million limited partner units, or 26.3 percent, of which 68.2 million limited partner units were subordinated.

CenterPoint and the Company 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 the initial public offering. See Note 1 for more information regarding incentive distributions.

Distributions received from Enable were $139.3 million and $143.7 million during the years ended December 31, 2015 and 2014, respectively.

Related Party Transactions

Operating costs charged and related party transactions between the Company and its affiliate, Enable, since its formation on May 1, 2013 are discussed below. Prior to May 1, 2013, operating costs charged and related party transactions between the Company and Enogex Holdings were eliminated in consolidation. The Company's interest in Enogex Holdings was deconsolidated on May 1, 2013.

On May 1, 2013, the Company and Enable entered into a Services Agreement, Employee Transition Agreement, and other agreements whereby the Company agreed to provide certain support services to Enable such as accounting, legal, risk management and treasury functions for an initial term ending on April 30, 2016. The support services automatically extend year-to-year at the end of the initial term, unless terminated by Enable with at least 90 days’ notice. Enable may terminate the initial support services at any time with 180 days' notice if approved by the board of Enable's general partner. As of December 31, 2015, Enable terminated all support services except IT, payroll and benefits. Under these agreements, the Company charged operating costs to Enable of $12.0 million and $16.8 million for December 31, 2015 and 2014, respectively. The Company charges operating costs to OG&E and Enable based on several factors. Operating costs directly related to OG&E and Enable are assigned as such. Operating costs incurred for the benefit of OG&E and Enable are allocated either as overhead based primarily on labor costs or using the "Distrigas" method. Effective April 1, 2014, Enable’s general partner, the Company and CenterPoint agreed to reduce certain governance related costs billed to Enable for transition services.

Additionally, the Company agreed to provide seconded employees to Enable to support its operations for an initial term ending on December 31, 2014. The Company did not transfer any employees to Enable at the formation of the partnership or any time through December 31, 2014. In October 2014, CenterPoint, the Company and Enable agreed to continue the secondment to Enable for 192 employees that participate in the Company's defined benefit and retirement plans, beyond December 31, 2014. The remaining seconded employees were terminated from the Company on December 31, 2014 and were offered employment by Enable. The Company billed Enable for reimbursement of $32.1 million and $104.8 million in 2015 and 2014, respectively, under the Transitional Seconding Agreement for employment costs incurred on or after May 1, 2013.

The Company had accounts receivable from Enable of $1.7 million and $5.6 million as of December 31, 2015 and 2014, respectively, for amounts billed for transitional services, including the cost of seconded employees.

Enable reimbursed the Company for Mr. Delaney's services as interim President and Chief Executive Officer for the months of June through November, 2015. Enable paid Mr. Delaney directly for his services for the period from December 1, 2015 to December 31, 2015.

OG&E entered into a new contract with Enable to provide transportation services effective May 1, 2014 which eliminated the natural gas storage services. This transportation agreement grants Enable the responsibility of delivering natural gas to OG&E’s generating facilities and performing an imbalance service. With this imbalance service, in accordance with the cash-out provision of the contract, OG&E purchases gas from Enable when Enable’s deliveries exceed OG&E’s pipeline receipts. Enable purchases gas from OG&E when OG&E’s pipeline receipts exceed Enable’s deliveries. The following table summarizes related party transactions between OG&E and Enable during the years ended December 31, 2015, 2014 and the eight months ended December 31, 2013.

	Year Ended December 31,		
(In millions)	**2015**	2014	2013
Operating Revenues:			
Electricity to power electric compression assets	**$ 13.8**	$ 13.3	$ 7.7
Cost of Sales:			
Natural gas transportation services	**$ 35.0**	$ 34.9	$ 23.2
Natural gas storage services	**—**	4.4	8.6
Natural gas purchases/(sales)	**7.6**	8.7	14.8

Summarized Financial Information of Enable

Summarized unaudited financial information for 100 percent of Enable is presented below for the years ended December 31, 2015 and 2014 and for the eight months ended December 31, 2013.

Balance Sheet	December 31,	
(In millions)	**2015**	2014
Current assets	**$ 381**	$ 438
Non-current assets	**10,857**	11,399
Current liabilities	**615**	671
Non-current liabilities	**3,092**	2,344

Income Statement	Year Ended December 31,		
(In millions)	**2015**	2014	2013
Operating revenues	**$ 2,418**	$ 3,367	$ 2,123
Cost of natural gas and natural gas liquids	**1,097**	1,914	1,241
Operating income (loss)	**(712)**	586	322
Net income (loss)	**(752)**	530	289

The formation of Enable was considered a business combination, and CenterPoint was the acquirer of Enogex Holdings for accounting purposes. Under this method, the fair value of the consideration paid by CenterPoint 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 Enable's equity of $2.2 billion. Due to the contribution of Enogex LLC to Enable meeting the requirements of being in substance real estate and the recording the initial investment at historical cost, the effects of the amortization and depreciation expense associated with the fair value adjustments on Enable's results of operations have been eliminated in the Company's recording of its equity in earnings of Enable.

The Company recorded equity in earnings of unconsolidated affiliates of $15.5 million and $172.6 million for the years ended December 31, 2015 and 2014, respectively. Equity in earnings of unconsolidated affiliates includes OGE Energy's share of Enable earnings adjusted for the amortization of the basis difference of OGE Energy's original investment in Enogex LLC and its underlying equity in net assets of Enable. The basis difference is the result of the initial contribution of Enogex LLC to Enable in May 2013, and subsequent issuances of equity by Enable, including the initial public offering in April 2014 and the issuance of common units for the acquisition of CenterPoint's 24.95 percent interest in SESH. 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, as described above.

The difference between OGE Energy's investment in Enable and its underlying equity in the net assets of Enable was $783.5 million as of December 31, 2015.

The following table reconciles OGE Energy's equity in earnings of its unconsolidated affiliates for the years ended December 31, 2015 and 2014.

	Year Ended December 31,	
(In millions)	**2015**	2014
OGE's share of Enable Net Income (Loss)	**$ (16.0)**	$ 143.1
Amortization of basis difference	**13.5**	14.0
Elimination of Enogex Holdings fair value and other adjustments	**18.0**	15.5
Equity in earnings of unconsolidated affiliates	**$ 15.5**	$ 172.6

Enable tests its goodwill for impairment annually on October 1, or more frequently if events or changes in circumstances indicate that the carrying value of goodwill may not be recoverable. Goodwill is assessed for impairment by comparing the fair value of the reporting unit with its book value, including goodwill. Subsequent to the completion of the October 1, 2014 annual goodwill impairment test and previous interim assessment as of December 31, 2014, the crude oil and natural gas industry was impacted by further commodity price declines, which consequently resulted in decreased producer activity in certain regions in which Enable operates. Based on the decline in producer activity and the forecasted impact on future periods, in addition to an increase in the weighted average cost of capital, Enable determined that the impact on its forecasted operating profits and cash flows for its gathering and processing and transportation and storage segments for the next five years would be significantly reduced. As a result, when Enable performed the first step of its annual goodwill impairment analysis as of October 1, 2015, it determined that the carrying value of the gathering and processing and transportation and storage segments exceeded fair value. Enable completed the second step of the goodwill impairment analysis comparing the implied fair value for those reporting units to the carrying amount of that goodwill and determined that goodwill for those units was completely impaired in the amount of $1,086.4 million as of September 30, 2015.

Accordingly, the Company recorded a $108.4 million pre-tax charge in the third quarter of 2015 for its share of the goodwill impairment, as adjusted for the basis differences.

4. Fair Value Measurements

The classification of the Company's fair value measurements requires judgment regarding the degree to which market data is 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 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.

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.

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 had no financial instruments measured at fair value on a recurring basis at December 31, 2015 and 2014, 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 with the exception of the Tinker Debt which fair value was based on calculating the net present value of the monthly payments discounted by the Company's current borrowing rate and is classified as Level 3 in the fair value hierarchy. The Company's long-term debt is recorded at the carrying amount. The following table summarizes the fair value and carrying amount of the Company's long-term debt at December 31, 2015 and 2014.

	2015		2014	
December 31 *(In millions)*	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Long-Term Debt				
OG&E Senior Notes	**$ 2,510.2**	**$ 2,754.6**	$ 2,509.7	$ 2,957.7
OG&E Industrial Authority Bonds	**135.4**	**135.4**	135.4	135.4
OG&E Tinker Debt	**10.0**	**9.2**	10.2	10.3
OGE Energy Senior Notes	**100.0**	**99.9**	100.0	99.9

5. 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 who 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.

Income Statement Presentation Related to Derivative Instruments

The Company had no derivative instruments included in its Consolidated Statements of Income in 2015 or 2014. The following tables present the effect of derivative instruments on the Company's Consolidated Statements 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)

6. Stock-Based Compensation

In 2013, the Company adopted, and its shareholders approved, the Stock Incentive Plan. The Stock Incentive Plan replaced the 2008 Plan and no further awards will be granted under the 2008 Plan. Under the 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 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, 2015, 2014 and 2013 related to the Company's performance units and restricted stock.

Year ended December 31 *(In millions)*	**2015**	2014	2013
Performance units			
Total shareholder return	**$ 7.6**	$ 8.3	$ 8.4
Earnings per share	**0.7**	3.7	2.3
Total performance units	**8.3**	12.0	10.7
Restricted stock	**0.1**	—	0.4
Total compensation expense	**8.4**	12.0	11.1
Less: Amount paid by unconsolidated affiliates	**0.5**	3.6	3.1
Net compensation expense	**$ 7.9**	$ 8.4	$ 8.0
Income tax benefit	**$ 3.1**	$ 3.3	$ 3.1

The Company has issued new shares to satisfy stock option exercises, restricted stock grants and payouts of earned performance units. In 2015, 2014 and 2013, there were 82,046 shares, 494,637 shares and 548,344 shares, respectively, of new common stock issued pursuant to the Company's Stock Incentive Plan related to exercised stock options, restricted stock grants (net of forfeitures) and payouts of earned performance units. In 2015, there were 1,070 shares of restricted stock returned to the Company to satisfy tax liabilities.

Performance Units

Under the 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 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, 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. 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 were not accrued or paid for awards prior to February 2014, and were therefore not included in the fair value calculation. Beginning with the February 2014 performance unit awards, dividends are accrued on a quarterly basis pending achievement of payout criteria, and were therefore included in the fair value calculations. 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.

	2015	2014	2013
Number of units granted	**264,454**	219,106	316,162
Fair value of units granted	**$ 31.02**	$ 34.80	$ 25.89
Expected dividend yield	**2.6%**	2.5%	2.8%
Expected price volatility	**16.9%**	20.0%	20.0%
Risk-free interest rate	**0.91%**	0.67%	0.37%
Expected life of units (in years)	**2.85**	2.86	2.84

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.

	2015	2014	2013
Number of units granted	**88,156**	73,037	74,570
Fair value of units granted	**$ 33.99**	$ 34.81	$ 26.73

Restricted Stock

Under the 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 on all restricted stock awards prior to July 2014, and therefore included in the fair value calculation. For all awards after July 2014, dividends will only be paid on any restricted stock awards that vest, accordingly dividends are no longer included in the fair value calculations. 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.

	2015	2014	2013
Shares of restricted stock granted	**958**	7,037	5,940
Fair value of restricted stock granted	**$ 26.11**	$ 35.71	$ 29.71

A summary of the activity for the Company's performance units and restricted stock at December 31, 2015 and changes in 2015 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 12/31/14	892,991		297,687		12,501	
Granted	**264,454 (A)**		**88,156 (A)**		**958**	
Converted	**(343,395) (B)**	**$ 0.2**	**(114,366) (B)**	**$ 4.9**	**N/A**	
Vested	**N/A**		**N/A**		**(4,772)**	**$ 0.1**
Forfeited	**(89,992)**		**(30,007)**		**(1,064)**	
Units/Shares Outstanding at 12/31/15	**724,058**	**$ —**	**241,470**	**$ —**	**7,623**	**$ 0.3**
Units/Shares Fully Vested at 12/31/15	**327,115**	**$ —**	**109,154**	**$ —**		

(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 performance units that vested at December 31, 2014 which were settled in February 2015.

A summary of the activity for the Company's non-vested performance units and restricted stock at December 31, 2015 and changes in 2015 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 12/31/14	556,844		$ 29.38	185,737		$ 29.90		12,501	$ 32.65	
Granted	**264,454**	**(A)**	**$ 31.02**	**88,156**	**(A)**	**$ 33.99**		**958**	**$ 26.11**	
Converted	**(7,248)**	**(B)**	**$ 28.95**	**(2,416)**	**(B)**	**$ 28.95**		**N/A**	**N/A**	
Vested	**(327,115)**		**$ 25.89**	**(109,154)**		**$ 26.73**		**(4,772)**	**$ 32.33**	
Forfeited	**(89,992)**		**$ 31.48**	**(30,007)**		**$ 32.95**		**(1,064)**	**$ 25.87**	
Units/Shares Non-Vested at 12/31/15	**396,943**		**$ 32.83**	**132,316**		**$ 34.30**		**7,623**	**$ 29.68**	
Units/Shares Expected to Vest	**390,820**	**(C)**		**130,274**	**(C)**			**7,623**		

(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) Units paid out under terms of plan to member on long-term disability.
(C) There is no intrinsic value of the performance units based on total shareholder return and earnings per share.

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)*	**2015**	2014	2013
Performance units			
Total shareholder return	**$ 8.5**	$ 9.5	$ 8.2
Earnings per share	**—**	3.8	4.9
Restricted stock	**0.2**	0.2	0.7

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, 2015	Unrecognized Compensation Cost *(in millions)*	Weighted Average to be Recognized *(in years)*
Performance units		
Total shareholder return	**$ 6.7**	**1.68**
Earnings per share	**2.4**	**1.69**
Total performance units	**9.1**	
Restricted stock	**0.1**	**1.60**
Total	**$ 9.2**	

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 had a contractual life of 10 years and none are outstanding.

A summary of the activity for the Company's exercised stock options in 2013 is shown in the following table.

Year ended December 31 *(In millions)*	2013
Intrinsic value (A)	$ 1.4
Cash received from stock options exercised	0.4

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

7. 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)*	**2015**	2014	2013
NON-CASH INVESTING AND FINANCING ACTIVITIES			
Power plant long-term service agreement	**$ 2.3**	$ —	$ 9.7
Investment in Enable (Note 3)	**—**	—	1,248.6
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash paid during the period for			
Interest (net of interest capitalized) (A)	**$ 145.4**	$ 150.8	$ 151.1
Income taxes (net of income tax refunds)	**(3.4)**	0.2	(1.1)

(A) Net of interest capitalized of $4.2 million, $2.4 million and $5.4 million in 2015, 2014 and 2013, respectively.

8. Income Taxes

The items comprising income tax expense are as follows:

Year ended December 31 *(In millions)*	**2015**	2014	2013
Provision (Benefit) for Current Income Taxes			
Federal	**$ —**	$ —	$ —
State	**(5.2)**	(4.5)	4.3
Total Provision (Benefit) for Current Income Taxes	**(5.2)**	(4.5)	4.3
Provision for Deferred Income Taxes, net			
Federal	**98.8**	160.0	154.4
State	**4.5**	18.2	(26.4)
Total Provision for Deferred Income Taxes, net	**103.3**	178.2	128.0
Deferred Federal Investment Tax Credits, net	**(0.7)**	(0.9)	(2.0)
Total Income Tax Expense	**$ 97.4**	$ 172.8	$ 130.3

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 2012 or state and local tax examinations by tax authorities for years prior to 2011. 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 tax rates to the effective income tax rate:

Year ended December 31	**2015**	2014	2013
Statutory Federal tax rate	**35.0 %**	35.0 %	35.0 %
Federal renewable energy credit (A)	**(8.9)**	(6.7)	(7.2)
Remeasurement of state deferred tax liabilities	**(0.8)**	0.4	(4.1)
401(k) dividends	**(0.7)**	(0.5)	(0.5)
Federal investment tax credits, net	**(0.2)**	(0.2)	(0.4)
Income attributable to noncontrolling interest	**—**	—	(0.3)
State income taxes, net of Federal income tax benefit	**0.1**	1.2	0.4
Uncertain tax positions	**0.7**	0.5	1.5
Amortization of net unfunded deferred taxes	**0.9**	0.6	0.6
Other	**0.3**	0.1	(0.1)
Effective income tax rate	**26.4 %**	30.4 %	24.9 %

(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. As discussed in Note 2, the Company early adopted for the year ended December 31, 2015, ASU 2015-17, Balance Sheet Classification of Deferred Taxes, which requires all deferred tax liabilities and assets, and any related valuation allowance, to be classified as non-current on the balance sheet. The Company's adoption was applied prospectively, and as such, the 2014 presentation of deferred taxes were not retroactively adjusted. The components of Deferred Income Taxes at December 31, 2015 and 2014, respectively, were as follows:

December 31 *(In millions)*	2014
Current Deferred Income Tax Assets	
Net operating losses	$ 158.4
Accrued liabilities	15.6
Federal tax credits	12.4
Accrued vacation	4.4
Uncollectible accounts	0.6
Total Current Deferred Income Tax Assets	$ 191.4

December 31 (In millions)	**2015**	2014
Non-Current Deferred Income Tax Liabilities, net		
Accelerated depreciation and other property related differences	**$ 2,016.0**	$ 1,936.8
Investment in Enable Midstream Partners	**623.4**	641.8
Company pension plan	**13.7**	34.6
Income taxes refundable to customers, net	**22.0**	21.7
Regulatory asset	**32.7**	24.7
Bond redemption-unamortized costs	**4.8**	5.3
Derivative instruments	**1.5**	1.8
Federal tax credits	**(184.4)**	(139.0)
State tax credits	**(106.7)**	(98.6)
Net operating losses	**(94.6)**	(19.8)
Postretirement medical and life insurance benefits	**(56.2)**	(56.4)
Regulatory liabilities	**(46.3)**	(58.0)
Asset retirement obligations	**(22.5)**	(21.4)
Accrued liabilities	**(14.0)**	—
Accrued vacation	**(3.2)**	—
Deferred Federal investment tax credits	**(0.9)**	(0.4)
Uncollectible accounts	**(0.5)**	—
Other	**(6.6)**	(4.8)
Non-Current Deferred Income Tax Liabilities, net	**$ 2,178.2**	$ 2,268.3

As of December 31, 2015, the Company has classified $13.2 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, 2015, 2014, and 2013.

(In millions)	**2015**	2014	2013
Balance at January 1	**$ 10.5**	$ 7.8	$ —
Tax positions related to current year:			
Additions	**2.7**	2.7	2.7
Tax positions related to prior years:			
Additions	**—**	—	5.1
Balance at December 31	**$ 13.2**	$ 10.5	$ 7.8

Where applicable, the Company classifies income tax-related interest and penalties as interest expense and other expense, respectively. During the year ended December 31, 2015, 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 $13.2 million as of December 31, 2015.

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 2015, OG&E recorded an additional reserve for this item of $4.2 million ($2.7 million after the federal tax benefit) related to the same Oklahoma investment tax credits generated in the current year 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.

Other

The Company sustained Federal and state tax operating losses through 2013 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 2015. 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 generated 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	$ 695.5	$ 25.6	2030
Federal operating loss	197.3	69.0	2030
Federal tax credits	184.4	184.4	2029
State tax credits			
Oklahoma investment tax credits	127.8	83.0	N/A
Oklahoma capital investment board credits	7.3	7.3	N/A
Oklahoma zero emission tax credits	24.3	16.4	2020

The Company has a Federal tax operating loss primarily caused by numerous extensions of accelerated tax bonus depreciation provision which allowed the Company to record current income tax deductions for the cost of certain property placed into service. During 2013, the Company began to utilize these net operating losses.

On December 18, 2015, the Protecting Americans from Tax Hikes Act was signed into law. Among other things, the law included an extension of bonus depreciation for 2015, 2016 and 2017 at a rate of 50 percent. The law reduces the bonus depreciation to 40 percent and 30 percent in 2018 and 2019, respectively. The impact of the new law was reflected in the Company's 2015 Consolidated Financial Statements as an increase in Deferred Tax Liabilities with a corresponding increase in Deferred Tax Assets related to the net operating loss. With this extension of bonus depreciation, the Company's utilization of net operating losses will continue into 2016.

The Company has generated excess tax benefits of $28.3 million related to its equity based compensation plan which have not been recognized during the time it has been in a net operating loss position. This balance is available to offset future taxable income in addition to the net operating loss balances presented above. The tax benefit and the credit to additional paid-in capital related to these payments will be recorded at a future date when the deduction reduces current taxes payable.

9. Common Equity

Automatic Dividend Reinvestment and Stock Purchase Plan

The Company issued 217,370 shares of common stock under its Automatic Dividend Reinvestment and Stock Purchase Plan in 2015 and received proceeds of $7.2 million. The Company may, from time to time, issue additional shares under its Automatic Dividend Reinvestment and Stock Purchase Plan or purchase shares traded on the open market. At December 31, 2015, there were 4,774,442 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 and restricted stock. Basic and diluted earnings per share for the Company were calculated as follows:

(In millions)	**2015**	2014	2013
Net Income	**$ 271.3**	$ 395.8	$ 387.6
Average Common Shares Outstanding			
Basic average common shares outstanding	**199.6**	199.2	198.2
Effect of dilutive securities:			
Contingently issuable shares (performance and restricted stock units)	**—**	0.7	1.2
Diluted average common shares outstanding	**199.6**	199.9	199.4
Basic Earnings Per Average Common Share	**$ 1.36**	$ 1.99	$ 1.96
Diluted Earnings Per Average Common Share	**$ 1.36**	$ 1.98	$ 1.94

Dividend Restrictions

The Company’s Certificate of Incorporation places restrictions on the amount of common stock dividends it can pay when preferred stock is outstanding. As there is no preferred stock outstanding, that restriction did not place any effective limit on the Company’s ability to pay dividends to its shareholders. Pursuant to the leverage restriction in the Company’s revolving credit agreement, the Company must maintain a percentage of debt to total capitalization at a level that does not exceed 65 percent. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization, which results in the restriction of approximately $387.7 million of the Company’s retained earnings from being paid out in dividends. Accordingly, approximately $1.9 billion of the Company’s retained earnings as of December 31, 2015 are unrestricted for the payment of dividends.

The Company depends on receipts from its equity investment in Enable and dividends from OG&E to pay dividends to its shareholders. Enable’s partnership agreement requires that it distribute all “available cash”, as defined as cash on hand at the end of a quarter after the payment of expenses and the establishment of cash reserves, and cash on hand resulting from working capital borrowings made after the end of the quarter. Pursuant to the Federal Power Act, OG&E is restricted from paying dividends from its capital accounts. Dividends are paid from retained earnings. Pursuant to the leverage restriction in OG&E’s revolving credit agreement, OG&E must also maintain a percentage of debt to total capitalization at a level that does not exceed 65 percent. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization, which results in the restriction of approximately $411.0 million of OG&E’s retained earnings from being paid out in dividends. Accordingly, approximately $1.7 billion of OG&E’s retained earnings as of December 31, 2015 are unrestricted for the payment of dividends.

10. Long-Term Debt

A summary of the Company's long-term debt is included in the Consolidated Statements of Capitalization. At December 31, 2015, 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)
0.05%	-	0.13%	Garfield Industrial Authority, January 1, 2025	$	47.0
0.06%	-	0.19%	Muskogee Industrial Authority, January 1, 2025		32.4
0.05%	-	0.14%	Muskogee Industrial Authority, June 1, 2027		56.0
Total (redeemable during next 12 months)				$	135.4

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

Long-Term Debt Maturities

Maturities of the Company's long-term debt during the next five years consist of $110.2 million, $225.2 million, $250.1 million, $250.1 million and $0.1 million in years 2016, 2017, 2018, 2019 and 2020, respectively.

The Company has previously incurred costs related to debt refinancing. 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 in the Consolidated Balance Sheets and are being amortized over the life of the respective debt.

11. 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 agreement. As of December 31, 2015, the Company had no short-term debt compared to a balance of $98.0 million at December 31, 2014, at a weighted-average interest rate of 0.41 percent. The following table provides information regarding the Company's revolving credit agreements and available cash at December 31, 2015.

Entity		Aggregate Commitment		Amount Outstanding (A)	Weighted-Average Interest Rate	Maturity	
		(In millions)					
OGE Energy (B)	$	750.0	$	—	—% (D)	December 13, 2018	(E)
OG&E (C)		400.0		1.9	0.95% (D)	December 13, 2018	(E)
Total	$	1,150.0	$	1.9	0.95%		

(A) Includes direct borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit at December 31, 2015.
(B) This bank facility is available to back up the Company's commercial paper borrowings and to provide revolving credit borrowings. This bank facility can also be used as a letter of credit facility.
(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

contained an option, which could be exercised up to two times, to extend the term for an additional year. In the third quarter of 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 from December 13, 2016 to December 13, 2017. In the second quarter of 2014, the Company and OG&E utilized their second extension to extend the maturity of their respective credit facility from December 13, 2017 to December 13, 2018. As of December 31, 2015, commitments of approximately $16.3 million and $8.7 million of the Company's and OG&E's credit facilities, respectively, however, were not extended and, unless the non-extending lender is replaced in accordance with the terms of the credit facility, such commitments will expire December 13, 2017.

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 $800.0 million in short-term borrowings at any one time for a two-year period beginning January 1, 2015 and ending December 31, 2016.

12. Retirement Plans and Postretirement Benefit Plans

Pension Plan and Restoration of Retirement Income Plan

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. 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 2015 and 2014, the Company did not make any contributions to its Pension Plan. The Company has not determined whether it will need to make any contributions to the Pension Plan in 2016. Any contribution to the Pension Plan during 2016 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. The Company 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.

As discussed in Note 3, CenterPoint, the Company and Enable agreed to continue the secondment to Enable of 192 employees that participate in the Company's defined benefit and retirement plans beyond December 31, 2014, while 277 employees that participated in the Retirement Plan and 59 employees entitled to life insurance benefits only were terminated. As a result, the Company incurred a curtailment that reduced the pension expense charged to Enable by $0.2 million for the year ended December 31, 2014.

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 2015, 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, the Company recorded pension settlement charges of $16.2 million in the third quarter and $5.5 million in the fourth quarter of 2015, of which $14.0 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.

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 2015 and 2014. 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 Sheets. 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. 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, 2015 was $610.9 million and $24.6 million, respectively. The accumulated postretirement benefit obligation for the Pension Plan and the Restoration of Retirement Income Plan at December 31, 2014 was $688.4 million and $18.7 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:

	Pension Plan		Restoration of Retirement Income Plan		Postretirement Benefit Plans	
December 31 *(In millions)*	**2015**	2014	**2015**	2014	**2015**	2014
Change in Benefit Obligation						
Beginning obligations	**$ 725.0**	$ 658.1	**$ 19.7**	$ 14.0	**$ 280.9**	$ 258.2
Service cost	**16.1**	15.3	**1.3**	1.1	**1.5**	3.1
Interest cost	**26.1**	28.1	**0.7**	0.6	**10.3**	11.4
Plan curtailments	**—**	(0.7)	**—**	—	**—**	(0.6)
Plan settlements	**(60.7)**	—	**—**	—	**—**	—
Participants' contributions	**—**	—	**—**	—	**3.4**	3.4
Actuarial (gains) losses	**(11.3)**	79.3	**4.0**	4.1	**(55.1)**	19.5
Benefits paid	**(15.2)**	(55.1)	**(0.6)**	(0.1)	**(15.7)**	(14.1)
Ending obligations	**$ 680.0**	$ 725.0	**$ 25.1**	$ 19.7	**$ 225.3**	$ 280.9
Change in Plans' Assets						
Beginning fair value	**$ 679.8**	$ 654.9	**$ —**	$ —	**$ 59.6**	$ 61.4
Actual return on plans' assets	**(22.2)**	80.0	**—**	—	**(0.5)**	1.8
Employer contributions	**—**	—	**0.6**	0.1	**8.5**	7.1
Plan settlements	**(60.7)**	—	**—**	—	**—**	—
Participants' contributions	**—**	—	**—**	—	**3.4**	3.4
Benefits paid	**(15.2)**	(55.1)	**(0.6)**	(0.1)	**(15.7)**	(14.1)
Ending fair value	**$ 581.7**	$ 679.8	**$ —**	$ —	**$ 55.3**	$ 59.6
Funded status at end of year	**$ (98.3)**	**$ (45.2)**	**$ (25.1)**	**$ (19.7)**	**$ (170.0)**	**$ (221.3)**

Net Periodic Benefit Cost

	Pension Plan			Restoration of Retirement Income Plan			Postretirement Benefit Plans		
Year ended December 31 *(In millions)*	**2015**	2014	2013	**2015**	2014	2013	**2015**	2014	2013
Service cost	**$ 16.1**	$ 15.3	$ 19.0	**$ 1.3**	$ 1.1	$ 1.2	**$ 1.5**	$ 3.1	$ 4.3
Interest cost	**26.1**	28.1	26.7	**0.7**	0.6	0.5	**10.3**	11.4	10.3
Expected return on plan assets	**(46.0)**	(45.3)	(48.4)	**—**	—	—	**(2.4)**	(2.4)	(2.5)
Amortization of net loss	**18.0**	14.3	26.5	**0.6**	0.2	0.4	**13.9**	12.3	21.5
Amortization of unrecognized prior service cost (A)	**0.4**	1.7	1.8	**0.1**	0.2	0.3	**(16.5)**	(16.5)	(16.5)
Curtailment	**—**	(0.2)	—	**—**	—	—	**—**	—	—
Settlement	**21.7**	—	22.4	**—**	—	—	**—**	—	—
Total net periodic benefit cost	**36.3**	13.9	48.0	**2.7**	2.1	2.4	**6.8**	7.9	17.1
Less: Amount paid by unconsolidated affiliates	**4.2**	3.2	5.9	**0.1**	0.1	0.1	**1.3**	1.3	1.5
Net periodic benefit cost (B)	**$ 32.1**	$ 10.7	$ 42.1	**$ 2.6**	$ 2.0	$ 2.3	**$ 5.5**	$ 6.6	$ 15.6

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

(B) In addition to the $40.2 million, $19.3 million and $60.0 million of net periodic benefit cost recognized in 2015, 2014 and 2013, respectively, the Company recognized the following:

- an increase in pension expense in 2015, 2014 and 2013 of $12.8 million, $11.2 million and $5.8 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);
- an increase in postretirement medical expense in 2015, 2014 and 2013 of $5.8 million, $5.2 million and $0.6 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 2015 and 2013 of $14.0 million and $17.0 million related to pension settlement charges of $21.7 million and $22.4 million, respectively, in accordance with the Oklahoma pension tracker regulatory liability (see Note 1); and
- a deferral of pension expense in 2015 of $1.9 million related to the Arkansas jurisdictional portion of the pension settlement charge of $21.7 million.

(In millions)	**2015**	2014	2013
Capitalized portion of net periodic pension benefit cost	**$ 5.0**	$ 3.4	$ 6.4
Capitalized portion of net periodic postretirement benefit cost	**1.9**	2.0	4.5

Rate Assumptions

	Pension Plan and Restoration of Retirement Income Plan			Postretirement Benefit Plans		
Year ended December 31	**2015**	2014	2013	**2015**	2014	2013
Discount rate	**4.00%**	3.80%	4.60%	**4.25%**	3.80%	4.60%
Rate of return on plans' assets	**7.50%**	7.50%	8.00%	**4.00%**	4.00%	4.00%
Compensation increases	**4.20%**	4.20%	4.20%	**N/A**	N/A	N/A
Assumed health care cost trend:						
Initial trend	**N/A**	N/A	N/A	**6.10%**	7.85%	8.35%
Ultimate trend rate	**N/A**	N/A	N/A	**4.50%**	4.48%	4.48%
Ultimate trend year	**N/A**	N/A	N/A	**2026**	2028	2028

N/A - not applicable

The overall expected rate of return on plan assets assumption was 7.5 percent in both 2015 and 2014, which was used 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.

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 6.1 percent in 2016 with the rates trending downward to 4.5 percent by 2026. 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)*	**2015**	2014	2013
Effect on aggregate of the service and interest cost components	**$ —**	$ —	$ —
Effect on accumulated postretirement benefit obligations	**0.2**	0.1	0.1

ONE-PERCENTAGE POINT DECREASE			
Year ended December 31 *(In millions)*	**2015**	2014	2013
Effect on aggregate of the service and interest cost components	**$ 0.1**	$ 0.1	$ 0.1
Effect on accumulated postretirement benefit obligations	**0.7**	0.7	0.6

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 at least 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	Duration blended Barclays Aggregate & Long Government/Credit
Interest Rate Sensitive Fixed Income	Duration blended Barclays Aggregate & Long Government/Credit
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 managers are 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. A portfolio may invest up to 25 percent of the portfolio's market value in private placement, including 144A securities with or without registration rights and allow for futures to be traded in the portfolio. 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 $100.0 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 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, 2015 and 2014. There were no Level 3 investments held by the Pension Plan at December 31, 2015 and 2014.

(In millions)	**December 31, 2015**	**Level 1**	**Level 2**
Common stocks			
U.S. common stocks	**$ 189.0**	**$ 189.0**	**$ —**
Foreign common stocks	**19.1**	**19.1**	**—**
U.S. Government obligations			
U.S. treasury notes and bonds (A)	**158.9**	**158.9**	**—**
Mortgage-backed securities	**2.2**	**—**	**2.2**
Bonds, debentures and notes (B)			
Corporate fixed income and other securities	**140.2**	**—**	**140.2**
Mortgage-backed securities	**12.3**	**—**	**12.3**
Commingled fund (C)	**24.4**	**—**	**24.4**
Other	**6.9**	**—**	**6.9**
Foreign government bonds	**5.6**	**—**	**5.6**
U.S. municipal bonds	**4.9**	**—**	**4.9**
Interest-bearing cash	**11.5**	**11.5**	**—**
Money market fund	**11.7**	**—**	**11.7**
Preferred stocks (foreign)	**0.3**	**0.3**	**—**
Forward contracts			
Receivable (foreign currency)	**0.1**	**—**	**0.1**
Payable (foreign currency)	**(0.1)**	**—**	**(0.1)**
Total Plan investments	**$ 587.0**	**$ 378.8**	**$ 208.2**
Receivable from broker for securities sold	**—**		
Interest and dividends receivable	**3.5**		
Payable to broker for securities purchased	**(8.8)**		
Total Plan assets	**$ 581.7**		

(In millions)	December 31, 2014	Level 1	Level 2
Common stocks			
U.S. common stocks	$ 201.4	$ 201.4	$ —
Foreign common stocks	31.3	31.3	—
U.S. Government obligations			
U.S. treasury notes and bonds (A)	203.2	203.2	—
Mortgage-backed securities	20.6	—	20.6
Bonds, debentures and notes (B)			
Corporate fixed income and other securities	167.1	—	167.1
Mortgage-backed securities	19.3	—	19.3
Commingled fund (C)	25.1	—	25.1
Common/collective trust (D)	29.9	—	29.9
Foreign government bonds	7.2	—	7.2
U.S. municipal bonds	3.5	—	3.5
Interest-bearing cash	0.2	0.2	—
Preferred stocks (foreign)	1.2	1.2	—
Forward contracts			
Receivable (foreign currency)	11.3	—	11.3
Payable (foreign currency)	(15.6)	—	(15.6)
Total Plan investments	$ 705.7	$ 437.3	$ 268.4
Receivable from broker for securities sold	3.2		
Interest and dividends receivable	3.9		
Payable to broker for securities purchased	(33.0)		
Total Plan assets	$ 679.8		

(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 postretirement benefit costs to expense 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, 2015 and 2014. There were no Level 2 investments held by the postretirement benefit plans at December 31, 2015 and 2014.

(In millions)	**December 31, 2015**	**Level 1**	**Level 3**
Group retiree medical insurance contract (A)	**$ 46.8**	**$ —**	**$ 46.8**
Mutual funds investment			
U.S. equity investments	**7.8**	**7.8**	**—**
Money market funds investment	**0.7**	**0.7**	**—**
Total Plan investments	**$ 55.3**	**$ 8.5**	**$ 46.8**

(In millions)	December 31, 2014	Level 1	Level 3
Group retiree medical insurance contract (A)	$ 51.0	$ —	$ 51.0
Mutual funds investment			
U.S. equity investments	8.5	8.5	—
Money market funds investment	0.1	0.1	—
Total Plan investments	$ 59.6	$ 8.6	$ 51.0

(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)*		**2015**
Group retiree medical insurance contract		
Beginning balance	**$**	**51.0**
Interest income		**0.9**
Dividend income		**0.6**
Realized losses		**—**
Administrative expenses and charges		**(0.1)**
Net unrealized losses related to instruments held at the reporting date		**(1.1)**
Claims paid		**(4.5)**
Ending balance	**$**	**46.8**

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
2016	$	14.6
2017		14.6
2018		14.7
2019		14.7
2020		14.8
After 2020		72.4

The following table summarizes the benefit payments the Company expects to pay related to OGE Energy's 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
2016	$	66.2
2017		50.6
2018		52.2
2019		54.7
2020		58.9
After 2020		275.7

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 $1.5 million and $1.2 million at December 31, 2015 and 2014, 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; (ii) a contribution made on a non Roth after-tax basis; or (iii) a Roth contribution. 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. For employees hired or rehired on or after December 1, 2009, 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.

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 $11.6 million, $15.2 million and $14.2 million in 2015, 2014 and 2013, 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 prior participant elections, 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 2015, 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 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. As of December 31, 2015, there are no employees participating in the supplemental executive retirement plan.

13. Report of Business Segments

The Company reports its operations in two business segments: (i) the electric utility segment, which is engaged in the generation, transmission, distribution and sale of electric energy, and (ii) natural gas midstream operations segment.

As discussed in Note 3, in connection with the formation of Enable, effective May 1, 2013, OGE Energy deconsolidated its interest in Enogex Holdings and began accounting for its interest in Enable using the equity method of accounting. Accordingly, for periods through April 30, 2013, amounts reported for the natural gas midstream operations segment reflect the operating results of Enogex Holdings. Equity in earnings of unconsolidated affiliates in the natural gas midstream operations segment reflects OGE Energy's equity interest in Enable since May 1, 2013. Investment in unconsolidated affiliates in the natural gas midstream operations segment represents OGE Energy's investment in Enable.

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.

The following tables summarize the results of the Company's business segments for the years ended December 31, 2015, 2014 and 2013.

2015	Electric Utility	Natural Gas Midstream Operations	Other Operations	Eliminations	Total
(In millions)					
Operating revenues	$ **2,196.9**	$ **—**	$ **—**	$ **—**	$ **2,196.9**
Cost of sales	**865.0**	**—**	**—**	**—**	**865.0**
Other operation and maintenance	**444.5**	**7.5**	**(0.4)**	**—**	**451.6**
Depreciation and amortization	**299.9**	**—**	**8.0**	**—**	**307.9**
Taxes other than income	**87.1**	**—**	**4.1**	**—**	**91.2**
Operating income (loss)	**500.4**	**(7.5)**	**(11.7)**	**—**	**481.2**
Equity in earnings of unconsolidated affiliates (A)	**—**	**15.5**	**—**	**—**	**15.5**
Other income (expense)	**20.0**	**0.4**	**0.9**	**(0.3)**	**21.0**
Interest expense	**146.7**	**—**	**2.6**	**(0.3)**	**149.0**
Income tax expense (benefit)	**104.8**	**(1.0)**	**(6.4)**	**—**	**97.4**
Net income (loss)	$ **268.9**	$ **9.4**	$ **(7.0)**	$ **—**	$ **271.3**
Investment in unconsolidated affiliates	$ **—**	$ **1,194.4**	$ **—**	$ **—**	$ **1,194.4**
Total assets	$ **8,541.8**	$ **1,439.5**	$ **175.1**	$ **(559.0)**	$ **9,597.4**
Capital expenditures	$ **551.6**	$ **—**	$ **(3.8)**	$ **—**	$ **547.8**

(A) In September 2015, the Company recorded a $108.4 million pre-tax charge for its share of the goodwill impairment, as adjusted for the basis difference. See Note 3 for further discussion of Enable's goodwill impairment.

2014	Electric Utility	Natural Gas Midstream Operations	Other Operations	Eliminations	Total
(In millions)					
Operating revenues	$ 2,453.1	$ —	$ —	$ —	$ 2,453.1
Cost of sales	1,106.6	—	—	—	1,106.6
Other operation and maintenance	453.2	1.2	(14.8)	—	439.6
Depreciation and amortization	270.8	—	10.6	—	281.4
Taxes other than income	84.5	—	4.2	—	88.7
Operating income (loss)	538.0	(1.2)	—	—	536.8
Equity in earnings of unconsolidated affiliates	—	172.6	—	—	172.6
Other income (expense)	7.1	—	0.7	(0.2)	7.6
Interest expense	141.5	—	7.1	(0.2)	148.4
Income tax expense (benefit)	111.6	69.1	(7.9)	—	172.8
Net income (loss)	$ 292.0	$ 102.3	$ 1.5	$ —	$ 395.8
Investment in unconsolidated affiliates	$ —	$ 1,318.2	$ —	$ —	$ 1,318.2
Total assets	$ 8,266.2	$ 1,461.2	$ 129.2	$ (328.8)	$ 9,527.8
Capital expenditures	$ 565.4	$ —	$ 10.8	$ (6.9)	$ 569.3

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
Other income (expense)	10.1	8.9	(2.3)	(0.5)	16.2
Interest expense	129.3	10.6	8.1	(0.5)	147.5
Income tax expense (benefit)	113.5	26.9	(10.6)	0.5	130.3
Net income (loss)	292.6	106.5	(5.9)	0.6	393.8
Less: Net income attributable to noncontrolling interests	—	6.6	—	(0.4)	6.2
Net income attributable to OGE Energy	$ 292.6	$ 99.9	$ (5.9)	$ 1.0	$ 387.6
Investment in unconsolidated affiliates	$ —	$ 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

14. 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 the Company's noncancellable operating lease. Future minimum payments for noncancellable operating leases are as follows:

Year ended December 31 *(In millions)*	2016	2017	2018	2019	2020	After 2020	Total
Operating lease obligations							
Railcars	$ 4.2	$ 3.5	$ 2.4	$ 23.0	$ —	$ —	$ 33.1
Wind farm land leases	2.4	2.5	2.5	2.5	2.9	46.3	59.1
Noncancellable operating lease	0.8	0.8	0.7	—	—	—	2.3
Total operating lease obligations	$ 7.4	$ 6.8	$ 5.6	$ 25.5	$ 2.9	$ 46.3	$ 94.5

Payments for operating lease obligations were $7.7 million, $6.7 million and $8.8 million for the years ended December 31, 2015, 2014 and 2013, respectively.

OG&E Railcar Lease Agreement

OG&E has several noncancellable operating leases with purchase options, covering approximately 1,400 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 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.

On October 14, 2014, OG&E signed a separate three-year lease effective December 2014 for 131 railcars to replace railcars that have been taken out of service or destroyed.

On December 17, 2015, OG&E renewed the lease agreement effective February 1, 2016. At the end of the new lease term, which is February 1, 2019, 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 $20.1 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.

OG&E Wind Farm Land Lease Agreements

OG&E has operating leases related to land 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.

Noncancellable Operating Lease

On August 29, 2012, the Company 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.

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)	2016	2017	2018	2019	2020	Total
Other purchase obligations and commitments						
Cogeneration capacity and fixed operation and maintenance payments	$ 79.8	$ 77.0	$ 74.0	$ 66.6	$ 54.7	$ 352.1
Expected cogeneration energy payments	58.3	42.7	55.2	57.6	55.1	268.9
Minimum fuel purchase commitments	299.6	127.5	40.7	11.7	—	479.5
Expected wind purchase commitments	58.6	58.8	57.0	55.8	56.6	286.8
Long-term service agreement commitments	2.5	2.6	43.2	2.8	2.9	54.0
Mustang Modernization expenditures	103.4	12.9	17.7	—	—	134.0
Environmental compliance plan expenditures	150.5	119.9	50.8	4.1	—	325.3
Total other purchase obligations and commitments	$ 752.7	$ 441.4	$ 338.6	$ 198.6	$ 169.3	$ 1,900.6

Public Utility Regulatory Policy Act of 1978

At December 31, 2015, OG&E has a QF contract with Oklahoma Cogeneration LLC which expires on August 31, 2019 and a QF contract with AES-Shady Point, Inc. which expires on January 15, 2023. 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 MWs AES-Shady Point, Inc. QF contract and the 120 MWs Oklahoma Cogeneration LLC QF contract, OG&E purchases 100 percent of the electricity generated by the QFs.

For the years ended December 31, 2015, 2014 and 2013, OG&E made total payments to cogenerators of $124.0 million, $129.4 million and $134.8 million, respectively, of which $69.5 million, $72.3 million and $74.4 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 has coal contracts for purchases through December 2017. As a participant in the SPP Integrated Marketplace, OG&E now purchases a relatively small percentage of its natural gas supply through long-term agreements. Alternatively, OG&E relies on a combination of call natural gas agreements, whereby OG&E has the right but not the obligation to purchase a defined quantity of natural gas, combined with day and intra-day purchases to meet the demands of the SPP Integrated Marketplace.

OG&E Wind Purchase Commitments

OG&E's current wind power portfolio includes the following, in addition to the 120 MW Centennial, 101 MW OU Spirit and 228 MW Crossroads wind farms owned by OG&E: (i) 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, (ii) access to up to 152 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 2031, (iii) 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 2031 and (iv) 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, 2015, 2014 and 2013.

Year ended December 31 *(In millions)*	**2015**	2014	2013
CPV Keenan	**$ 26.7**	$ 28.1	$ 30.9
Edison Mission Energy	**19.7**	21.3	20.6
FPL Energy	**3.2**	3.6	3.3
NextEra Energy	**7.0**	7.8	7.2
Total wind power purchased	**$ 56.6**	$ 60.8	$ 62.0

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. In May 2013, a new contract was signed that is expected to run for the earlier of 128,000 factored-fired hours or 4,800 factored-fired starts. On December 30, 2015, the McClain LTSA was amended to define the terms and conditions for the exchange of spare rotors between OG&E and General Electric International, Inc. 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 2028. The contract requires payments based on both a fixed and variable cost component, depending on how much the Redbud Plant is used.

Enable Gas Transportation Agreement

OG&E contracts with Enable for gas transportation services. On March 17, 2014, OG&E entered into a new five year firm no-notice load following gas transportation contract with Enable effective May 1, 2014.

Environmental Laws and Regulations

The activities of OG&E are subject to numerous stringent and complex Federal, state and local laws and regulations governing environmental protection. These laws and regulations can change, restrict or otherwise impact OG&E's business activities in many ways including the handling or disposal of waste material, future construction activities to avoid or mitigate harm to threatened or endangered species and requiring the installation and operation of emissions 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. OG&E believes that its operations are in substantial compliance with current Federal, state and local environmental standards.

Environmental regulation can increase the cost of planning, design, initial installation and operation of OG&E's 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 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.

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.

On July 8, 2013, the U.S. Department of Justice filed a complaint against OG&E in United States District Court for the Western District of Oklahoma 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 intervened in this proceeding. On August 30, 2013, the government filed a Motion for Summary Judgment and on September 6, 2013, OG&E filed a Motion to Dismiss the case. On January 15, 2015, U.S. District Judge Timothy DeGuisti dismissed the complaints filed by the EPA and the Sierra Club. The Court held that it lacked subject matter jurisdiction over plaintiffs' claims because plaintiffs failed to present an actual "case or controversy" as required by Article III of the Constitution. The court also ruled in the alternative that, even if plaintiffs had presented a case or controversy, it would have nonetheless "decline[d] to exercise jurisdiction." The EPA and the Sierra Club did not file an appeal of the Court's ruling.

On August 12, 2013, the Sierra Club filed a separate complaint against OG&E in the United States District Court for the Eastern District of Oklahoma alleging that OG&E projects at Muskogee Unit 6 in 2008 were made without obtaining a prevention of significant deterioration permit and that the plant had exceeded emissions limits for opacity and particulate matter. The Sierra Club seeks a permanent injunction preventing OG&E from operating the Muskogee generating plant. On March 4, 2014, the Eastern District dismissed the prevention of significant deterioration permit claim based on the statute of limitations, but allowed the opacity and particulate matter claims to proceed. To obtain the right to appeal this decision, the Sierra Club subsequently withdrew a Notice of Intent to Sue for additional Clean Air Act violations and asked the Eastern District to dismiss its remaining claims with prejudice. On August 27, 2014, the Eastern District granted the Sierra Club's request. The Sierra Club has filed a Notice of Appeal with the 10th Circuit where oral argument was held on March 18, 2015.

At this time, OG&E continues to believe that it has acted in compliance with the Federal Clean Air Act, and OG&E expects to vigorously defend against the claims that have been asserted. If OG&E does not prevail in the remainder of the proceedings, the EPA and the Sierra Club could seek to require OG&E to install additional pollution control equipment, including dry scrubbers, baghouses and selective catalytic reduction systems with capital costs in excess of $1.1 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. Due to the uncertain and preliminary nature of this litigation, OG&E cannot provide a range of reasonably possible loss in this case.

Air Quality Control System

On September 10, 2014, OG&E executed a contract for the design, engineering and fabrication of two circulating dry scrubber systems to be installed at Sooner Units 1 and 2. OG&E entered into an agreement on February 9, 2015, to install the dry scrubber systems. The dry scrubbers are part of OG&E's ECP and scheduled to be completed by 2019. More detail regarding the ECP can be found under the "Pending Regulatory Matters" in Note 15.

Clean Power Plan

On October 23, 2015, the EPA published the final Clean Power Plan that established standards of performance for CO_2 emissions from existing fossil-fuel-fired power plants along with state-specific CO_2 reduction standards expressed as both rate-based (lbs/MWh) and mass-based (tons/yr) goals. The 2030 rate-based reduction requirement for all existing generating units in Oklahoma has decreased from a proposed 43 percent reduction to 32 percent in the final rule. The mass-based approach for existing units calls for a 24 percent reduction by 2030 in Oklahoma. The Clean Power Plan requires that states submit to the EPA plans for achieving the state-specific CO_2 reduction goals by September 6, 2016 or submit an extension request for up to two years. The compliance period was to begin in 2022, and emission reductions were to be phased in by 2030. The EPA also proposed a federal compliance plan to implement the Clean Power Plan in the event that an approvable state plan was not submitted to the EPA by the required deadline.

A number of states have filed lawsuits against the Clean Power Plan. On February 9, 2016, the U.S. Supreme Court issued orders staying implementation of the Clean Power Plan pending resolution of challenges to the rule. The company is unable to determine what impact the lawsuits will ultimately have on the Clean Power Plan or what impact the stay in implementation will have; however, if the Clean Power Plan survives judicial review and is implemented as written, it 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. Significant uncertainties would remain with regards to potential implementation in Oklahoma (and the federal plan that would be imposed by the EPA for states that do not submit approvable plans), including whether states would elect an emissions standards approach versus a state measures approach, whether and what type of emissions trading would be allowed, and available cost mitigation options. Due to the pending litigation and the uncertainties in the state approaches, the ultimate timing and impact of these standards on our operations cannot be determined with certainty at this time.

Siemens Contract

On June 15, 2015 OG&E entered into a contract with Siemens Energy Inc. for the purchase, design and engineering of seven simple-cycle gas turbine generators for $170.3 million to be completed by June 1, 2018.

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 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 current available information, 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.

15. 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 2015, 86 percent of OG&E's electric revenue was subject to the jurisdiction of the OCC, eight percent to the APSC and six percent to the FERC.

The OCC issued an order in 1996 authorizing OG&E to reorganize into a subsidiary of the Company. The order required that, among other things, (i) the Company permit the OCC access to the books and records of the Company and its affiliates relating to transactions with OG&E, (ii) the Company employ accounting and other procedures and controls to protect against subsidization of non-utility activities by OG&E's customers and (iii) the Company refrain from pledging OG&E assets or income for affiliate transactions. In addition, the Energy Policy Act of 2005 enacted the Public Utility Holding Company Act of 2005, which in turn granted to the FERC access to the books and records of the Company and its affiliates as the FERC deems relevant to costs incurred by OG&E or necessary or appropriate for the protection of utility customers with respect to the FERC jurisdictional rates.

Completed Regulatory Matters

Fuel Adjustment Clause Review for Calendar Year 2013

The OCC routinely reviews the costs recovered from customers through OG&E's fuel adjustment clause. On July 31, 2014, the OCC Staff filed an application to review OG&E's fuel adjustment clause for calendar year 2013, including the prudence of OG&E's electric generation, purchased power and fuel procurement costs. On May 21, 2015, the ALJ recommended that the OCC find that OG&E's 2013 electric generation, purchased power and fuel procurement processes and costs were prudent, accurate and properly applied to customer billing statements. OG&E received an order to that effect from the OCC on June 17, 2015.

Oklahoma Demand Program Rider

On January 6, 2016, the OCC approved OG&E's 2016 through 2018 demand portfolio programs. The order stipulates recovery of program costs, lost revenues and incentives resulting from those programs, through the Demand Program Rider.

Pending Regulatory Matters

Set forth below is a list of various proceedings pending before state or federal regulatory agencies. Unless stated otherwise, OG&E cannot predict when the regulatory agency will act or what action the regulatory agency will take. OG&E's financial results are dependent in part on timely and adequate decisions by the regulatory agencies that set OG&E's rates.

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 along with the corresponding process for allocating the costs of such expansions. Order No. 1000 requires individual regions to determine whether a previously-approved project is subject to reevaluation and is therefore governed by the new rule.

Order No. 1000 directs public utility transmission providers to remove from the FERC-jurisdictional tariff and agreement 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 or to 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's pre-Order No. 1000 tariff included 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 previous transmission projects in Oklahoma. On May 29, 2013, the Governor of Oklahoma 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 kV that interconnect to those incumbent owners' existing facilities.

The SPP has submitted compliance filings implementing Order No. 1000's requirements. In response, the FERC issued an order on the SPP filings that required the SPP to remove certain right of first refusal language from the SPP Tariff and the SPP Membership Agreement. On December 15, 2014, OG&E filed an appeal in the District of Columbia Court of Appeals challenging the FERC's order requiring the removal of the right of first refusal language from the SPP Membership Agreement. The court has not yet acted on OG&E's appeal.

The Company cannot, at this time, determine the precise impact of Order No. 1000 on OG&E. The Company has no reason to believe that the implementation of Order No. 1000 will impact those transmission projects for which OG&E has received a notice to proceed from the SPP.

Oklahoma Demand Program Rider Review - SmartHours Program

In July 2012, OG&E filed an application with the OCC to recover certain costs associated with Demand Programs through the Demand Program Rider, including the lost revenues associated with the SmartHours program. The SmartHours program is designed to incentivize participating customers to reduce on-peak usage or shift usage to off-peak hours during the months of May through October, by offering lower rates to those customers in the off-peak hours of those months. Lost revenues are created by the difference in the standard rates and the lower incentivized rates. Non-SmartHours program customers benefit from the reduction of on-peak usage by SmartHours customers by the reduction of more costly on-peak generation and the delay in adding new on-peak generation.

In December 2012, the OCC issued an order approving the recovery of costs associated with the Demand Programs, including the lost revenues associated with the SmartHours program, subject to the Oklahoma PUD staff review.

In March 2014, the Oklahoma PUD staff began their review of the Demand Program cost, including the lost revenues associated with the SmartHours program. In November 2014, OG&E believed that it had reached an agreement with the Oklahoma PUD staff on the methodology to be used to calculate lost revenues associated with the SmartHours program and the amount of lost revenue for 2013, which totaled $10.1 million. The agreement also included utilizing the same methodology for calculating lost revenues for 2014, which resulted in lost revenues for 2014 of $11.6 million.

In January 2015, OG&E implemented rates that began recovering the 2013 lost revenues, in accordance with the agreement that it believed had been reached with the Oklahoma PUD staff.

In April 2015, the Oklahoma PUD staff filed an application, seeking an order from the OCC, for determining the proper methodology for calculating lost revenues pursuant to OG&E’s Demand Program Rider, primarily affecting the SmartHours program lost revenues. In the application, the Oklahoma PUD staff recommends the OCC approve the Oklahoma PUD staff methodology for calculating lost revenues associated with the SmartHours program, which differs from the methodology that OG&E believes it agreed upon and which would result in recovery of lost revenue for 2013 of $4.9 million, a reduction of $5.2 million from the amount recorded by OG&E for 2013.

OG&E believes the methodology agreed to in November 2014 is consistent with the 2012 OCC order and it is probable that OG&E will recover the $10.1 million of lost revenues associated with 2013, the $11.6 million associated with 2014 and the $14.9 million associated with 2015. A hearing was held on June 30, 2015 and July 1, 2015. OG&E is unable to predict when it will receive a ruling from the OCC.

Environmental Compliance Plan

On August 6, 2014, OG&E filed an application with the OCC for approval of its plan to comply with the EPA's MATS and Regional Haze FIP while serving the best long-term interests of customers in light of future environmental uncertainties. The application sought approval of the ECP and for a recovery mechanism for the associated costs. The ECP includes installing dry scrubbers at Sooner Units 1 and 2 and the conversion of Muskogee Units 4 and 5 to natural gas. The application also asks the OCC to predetermine the prudence of its Mustang Modernization Plan which calls for replacing OG&E's soon-to-be retired Mustang steam turbines in late 2017 with 400 MWs of new, efficient combustion turbines at the Mustang site in 2018 and 2019 and approval for a recovery mechanism for the associated costs. OG&E estimates the total capital cost associated with its environmental compliance plan to be approximately $1.1 billion. The OCC hearing on OG&E's application before an ALJ began on March 3, 2015 and concluded on April 8, 2015. Multiple parties advocating a variety of positions intervened in the proceeding.

On June 8, 2015, the ALJ issued his report on OG&E's application. While the ALJ in his report agreed that the installation of dry scrubbers at Sooner Units 1 and 2 and the conversion of Muskogee Units 4 and 5 to natural gas pursuant to OG&E's ECP is the best approach, the ALJ's report included several recommendations. OG&E filed exceptions to the ALJ's report and on July 21, 2015, Commissioner Bob Anthony issued his deliberation statement that was consistent with many parts of the ALJ's report, including the ALJ's support of OG&E's ECP, the ALJ's recommendation to pre-approve certain estimated costs of the environmental recovery plan, and the ALJ's recommendation to defer all other cost recovery issues until the next general rate case.

On December 2, 2015, OG&E received an order from the OCC denying, by a two to one vote, its plan to comply with the environmental mandates of the Federal Clean Air Act, Regional Haze and MATS. The OCC also denied OG&E's request for pre-approval of its Mustang Modernization Plan, revised depreciation rates for both the retirement of the Mustang units and the replacement combustion turbines and pre-approval of early retirement and replacement of generating units at its Mustang site, including cost recovery through a rider.

On December 11, 2015, OG&E filed a motion requesting modification of the OCC order for the purposes of approving only the ECP. OG&E did not seek modification to any other provisions of the OCC order, including cost recovery. OG&E also agreed that it would not implement a rider for recovery of the costs of the ECP until and unless authorized by the OCC in a subsequent proceeding. On December 23, 2015, the OCC rejected, by a two to one vote, a proposal by Commissioner Dana Murphy to grant OG&E's December 11, 2015 motion.

On February 12, 2016, OG&E filed an application requesting the OCC to issue an order approving the installation of dry scrubbers at the Sooner facility, on or before May 2, 2016. The application states that if the application is not approved by May 2, 2016, OG&E will decide at that time whether to cancel the dry scrubber equipment and installation contracts and make plans to convert the Sooner coal units to natural gas. As of December 31, 2015, OG&E had incurred $94.8 million of construction work in progress on the dry scrubbers. OG&E estimates another $35.0 million of in-process expenditures will be incurred prior to May 1, 2016. Additionally, if the request is not approved, OG&E expects to seek recovery in subsequent proceedings for the expenditures incurred for the dry scrubber project and reasonable stranded costs associated with the discontinuance of the Sooner coal units.

Fuel Adjustment Clause Review for Calendar Year 2014

On July 28, 2015, the OCC staff filed an application to review OG&E's fuel adjustment clause for calendar year 2014, 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 September 2, 2015. A hearing is scheduled to be held on April 7, 2016.

Integrated Resource Plans

In August 2015, OG&E initiated the process to update its IRP pursuant to the OCC rules. After engaging interested stakeholders in August and September, OG&E finalized the 2015 IRP and submitted it to the OCC on October 1, 2015. The 2015 IRP updated certain assumptions contained in the IRP submitted in 2014, but did not make any material changes to the ECP and other parts of the action plan contained in the IRP submitted in 2014.

Oklahoma Rate Case Filing

On December 18, 2015, OG&E filed a general rate case with the OCC requesting a rate increase of $92.5 million and a 10.25 percent return on equity based on a June 30, 2015 test year. OG&E primarily seeks to recover $1.6 billion of electric infrastructure additions since its last general rate case in Oklahoma, the impact of the expiration of OG&E's wholesale contracts and increased operating costs such as vegetation management.

Arkansas Rate Case Filing

OG&E intends to file a general rate case with the APSC by August 15, 2016.

16. 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	**2015**	**$ 480.1**	**$ 549.9**	**$ 719.8**	**$ 447.1**	**$ 2,196.9**
	2014	$ 560.4	$ 611.8	$ 754.7	$ 526.2	$ 2,453.1
Operating income	**2015**	**$ 56.4**	**$ 127.2**	**$ 250.8**	**$ 46.8**	**$ 481.2**
	2014	$ 61.8	$ 141.8	$ 248.1	$ 85.1	$ 536.8
Net income	**2015**	**$ 43.2**	**$ 87.5**	**$ 111.2**	**$ 29.4**	**$ 271.3**
	2014	$ 49.3	$ 100.8	$ 187.3	$ 58.4	$ 395.8
Basic earnings per average common share attributable	**2015**	**$ 0.22**	**$ 0.44**	**$ 0.55**	**$ 0.15**	**$ 1.36**
to OGE Energy common shareholders (A)	2014	$ 0.25	$ 0.51	$ 0.94	$ 0.29	$ 1.99
Diluted earnings per average common share	**2015**	**$ 0.22**	**$ 0.44**	**$ 0.55**	**$ 0.15**	**$ 1.36**
attributable to OGE Energy common shareholders (A)	2014	$ 0.25	$ 0.50	$ 0.94	$ 0.29	$ 1.98

(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.(the Company) as of December 31, 2015 and 2014, 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, 2015. 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 26.3 percent interest at December 31, 2015. The Company’s investment in Enable constituted 12.4 percent and 13.8 percent of the Company’s assets as of December 31, 2015 and 2014, respectively, and the Company’s equity earnings in the net income of Enable constituted 4.2 percent, 30.4 percent and 19.4 percent of the Company’s income before income taxes for the years ended December 31, 2015, 2014 and 2013, respectively. 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, 2015 and 2014, and the consolidated results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, 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, 2015, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 26, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
February 26, 2016

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

None.

Item 9A. Controls and Procedures.

The Company maintains a set of disclosure controls and procedures designed to ensure that information required to be disclosed by the Company in reports that it files or submits under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the Securities and Exchange Commission rules and forms. In addition, the disclosure controls and procedures ensure that information required to be disclosed is accumulated and communicated to management, including the chief executive officer and chief financial officer, allowing timely decisions regarding required disclosure. As of the end of the period covered by this report, based on an evaluation carried out under the supervision and with the participation of the Company's management, including the chief executive officer and chief financial officer, of the effectiveness of the Company's disclosure controls and procedures (as such term is defined in Rules 13a-15(e) and 15(d)-15(e) under the Securities Exchange Act of 1934), the chief executive officer and chief financial officer have concluded that the Company's disclosure controls and procedures are effective.

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

Management's Report on Internal Control Over Financial Reporting

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

The Company's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2015. 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 (2013). Based on our assessment, we believe that, as of December 31, 2015, 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/ Sean Trauschke	/s/ Scott Forbes
Sean Trauschke, Chairman of the Board, President and Chief Executive Officer	Scott Forbes, Controller and Chief Accounting Officer

/s/ Stephen E. Merrill

Stephen E. Merrill
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, 2015, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 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, 2015, 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, 2015 and 2014, 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, 2015 of OGE Energy Corp. and our report dated February 26, 2016 expressed an unqualified opinion thereon.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
February 26, 2016

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 "Investors", "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 preliminary proxy statement with the Securities and Exchange Commission on or about February 26, 2016. 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, 2015, 2014 and 2013
- Consolidated Statements of Comprehensive Income for the years ended December 31, 2015, 2014 and 2013
- Consolidated Statements of Cash Flows for the years ended December 31, 2015, 2014 and 2013
- Consolidated Balance Sheets at December 31, 2015 and 2014
- Consolidated Statements of Capitalization at December 31, 2015 and 2014
- Consolidated Statements of Changes in Stockholders' Equity for the years ended December 31, 2015, 2014 and 2013
- 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 over Financial Reporting)

(ii) The financial statements and Notes to Consolidated 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).
2.10	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, 2013 (File No. 1-12579) and incorporated by reference herein).
3.02	Copy of Amended OGE Energy Corp. By-laws dated November 30, 2015. (Filed as Exhibit 3.01 to OGE Energy's Form 8-K filed November 30, 2015 (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	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).
4.07	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).
4.08	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).
4.09	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).
4.10	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).
4.11	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).
4.12	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).
4.13	Supplemental Indenture No. 14 dated as of March 15, 2014 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 March 25, 2014 (File No. 1-1097) and incorporated by reference herein).
4.14	Supplemental Indenture No. 15 dated as of December 1, 2014 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 December 11, 2014 (File No. 1-1097) and incorporated by reference herein).
4.15	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).
4.16	Supplemental Indenture No. 2 dated as of November 24, 2014 between OGE Energy and UMB Bank, N.A, as trustee, creating the Senior Notes. (Filed as Exhibit 4.01 to OGE Energy's Form 8-K filed November 24, 2014 (File No. 1-12579) 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).

10.09*	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*	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).
10.15*	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).
10.16*	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).
10.17*	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).
10.18*	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).
10.19*	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).
10.20*	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).
10.21*	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).
10.22*	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).
10.23	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).
10.24*	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).
10.25*	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).
10.26	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).
10.27	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).
10.28	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).
10.29	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).
10.30*	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).

10.31*	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).
10.32*	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).
10.33*	Director Compensation.
10.34*	Executive Officer Compensation.
10.35	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).
10.36	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).
10.37	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).
10.38	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).
10.39*	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).
10.40*	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).
10.41	Letter of extension dated as of July 29, 2013 for OGE Energy'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).
10.42	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).
10.43*	Amendment No. 4 to the OGE Energy'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).
10.44*	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).
10.45*	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).
10.46*	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).
10.47	Seconded Amended and Restated Limited Liability Company Agreement of Enable GP, LLC as amended as of April 16, 2014 (Filed as exhibit 10.01 to OGE Energy's Form 8-K filed April 22, 2014 (File No. 1-12579) and incorporated by reference herein).
10.48	Second Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP dated April 16, 2014 (Filed as Exhibit 3.1 to Enable Midstream Partners, LP Form 8-K (File No. 1-36413) and incorporated by reference herein).
10.49	Letter of extension dated as of June 24, 2014 for OGE Energy'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 and Union Bank, N.A., as Co-Documentation Agents (Filed as Exhibit 10.01 to OGE Energy's Form 8-K filed June 25, 2014 (File No. 1-12579) and incorporated by reference herein).
10.50	Letter of extension dated as of June 24, 2014 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 and Union Bank, N.A., as Co-Documentation Agents (Filed as Exhibit 10.02 to OGE Energy's Form 8-K filed June 25, 2014 (File No. 1-12579) and incorporated by reference herein).

10.51	Letter of extension dated as of September 8, 2014 for OGE Energy'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 (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q filed November 5, 2014 (File No. 1-12579) and incorporated by reference herein).
10.52	Letter of extension dated as of June 24, 2014 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 and Union Bank, N.A., as Co-Documentation Agents (Filed as Exhibit 10.02 to OGE Energy's Form 8-K filed June 25, 2014 (File No. 1-12579) and incorporated by reference herein).
10.53*	Form of Performance Unit Agreement under OGE Energy's 2013 Stock Incentive Plan.
10.54*	Form of Restricted Stock Agreement under OGE Energy's 2013 Stock Incentive Plan.
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 for the Financial Statements of Enable Midstream Partners, LP.
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, 2015.
99.07	Financial Statements of Enable Midstream Partners, LP as of and for the three years ended December 31, 2013 (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed November 12, 2014 (File No. 1-12579) and incorporated by reference herein).
99.08	Copy of the Report of Administrative Law Judge dated June 8, 2015. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed June 12, 2015 (File No. 1-12579) and incorporated by reference herein).
99.09	Copy of OCC Order relating to OG&E's environmental compliance plan application (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed December 7, 2015 (File No. 1-12579) and incorporated by reference herein).
99.10	Copy of OG&E's Motion for Rehearing on its environmental compliance plan application (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed December 15, 2015 (File No. 1-12579) and incorporated by reference herein).
99.11	Copy of OG&E's Application with the OCC for general rate case (Filed and Exhibit 99.02 to OGE Energy's Form 8-K filed December 23, 2015 (File No. 1-12579) and incorporated by reference herein).
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Schema Document.
101.PRE	XBRL Taxonomy Presentation Linkbase Document.
101.LAB	XBRL Taxonomy Label Linkbase Document.
101.CAL	XBRL Taxonomy Calculation Linkbase Document.
101.DEF	XBRL Definition Linkbase Document.

* Represents executive compensation plans and arrangements.

OGE ENERGY CORP.

SCHEDULE II - Valuation and Qualifying Accounts

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Deductions (A)	Balance at End of Period
	(In millions)			
Balance at December 31, 2013				
Reserve for Uncollectible Accounts	$ 2.6	$ 2.5	$ 3.2	$ 1.9
Balance at December 31, 2014				
Reserve for Uncollectible Accounts	$ 1.9	$ 2.3	$ 2.6	$ 1.6
Balance at December 31, 2015				
Reserve for Uncollectible Accounts	**$ 1.6**	**$ 2.4**	**$ 2.6**	**$ 1.4**

(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 26th day of February, 2016.

OGE ENERGY CORP.
(Registrant)

By /s/ Sean Trauschke
Sean Trauschke
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/ Sean Trauschke Sean Trauschke	Principal Executive Officer and Director;	February 26, 2016
/s/ Stephen E. Merrill Stephen E. Merrill	Principal Financial Officer;	February 26, 2016
/s/ Scott Forbes Scott Forbes	Principal Accounting Officer.	February 26, 2016
Frank A. Bozich	Director;	
James H. Brandi	Director;	
Luke R. Corbett	Director;	
John D. Groendyke	Director;	
David L. Hauser	Director;	
Kirk Humphreys	Director;	
Robert O. Lorenz	Director;	
Judy R. McReynolds	Director;	
Sheila G. Talton	Director;	
/s/ Sean Trauschke By Sean Trauschke (attorney-in-fact)		February 26, 2016

Exhibit 10.33

OGE Energy Corp.
Director Compensation

Compensation of non-officer directors of the Company in 2015 included an annual retainer fee of $146,600, of which $51,600 was payable in cash in monthly installments and $95,000 was deposited in the director's account under the Company's Deferred Compensation Plan in December 2015 and converted to 3,859 common stock units based on the closing price of the Company's Common Stock on December 8, 2015. 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 $20,000 cash retainer in 2015. The chairman of the Audit Committee received an additional $15,000 cash retainer in 2015. The chairmen of the Compensation and Nominating and Corporate Governance Committees received an additional $10,000 annual cash retainer in 2015. Each member of the Audit Committee also received an additional annual retainer of $5,000 and the Chair of the Audit Committee received a meeting fee of $2,000 for significant meetings (wither in person or by phone) with management to address Committee matters. These amounts represent the total fees paid to directors in their capacities as directors of the Company and OG&E in 2015.

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 in 2015 were 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 2015, 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.

Exhibit 10.34

OGE Energy Corp.
Executive Officer Compensation

Executive Compensation

In December 2015, 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 2016. 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 2016 annual bonus targets and long-term awards are dependent on achievement of specified corporate goals established by the Compensation Committee and no officer is assured of any payout.

Salary

The Compensation Committee established the base salaries for its senior executive group. The salaries for 2016 for the OGE Energy officers who are expected to be named in the Summary Compensation Table in OGE Energy's 2016 Proxy Statement are as follows:

Executive Officer	2016 Base Salary
Sean Trauschke, Chairman, President and Chief Executive Officer	$840,000
Stephen E. Merrill, Chief Financial Officer	$440,000
E. Keith Mitchell, Chief Operating Officer of OG&E	$484,100
Jean C. Leger, Jr., Vice President - Utility Operations of OG&E	$353,806
Paul Renfrow, Vice President - Public Affairs and Corporate Administration	$354,900

Establishment of 2016 Annual Incentive Awards

As stated above, at its December 2015 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 2016 corporate goals to receive from 0 percent to 150 percent of such targeted amount. For 2016, the targeted amount ranged from 65 percent to 100 percent of the approved 2016 base salary for the executive officers in the above table.

Establishment of Long-Term Awards

At its December 2015 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. For 2016, the targeted amount ranged from 110 percent to 270 percent of the approved 2016 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 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. As of December 31, 2015, there are no employees participating in the supplemental executive retirement plan.

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; (ii) a contribution made on a non Roth after-tax basis; or (iii) a Roth contribution. 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. For employees hired or rehired on or after December 1, 2009, 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.

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 prior participant elections, 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 2015, 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 Plan Administration 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 Plan Administration 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 some instances the 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 2015 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 10.53

OGE ENERGY CORP.
FORM OF PERFORMANCE UNIT AGREEMENT
UNDER THE 2013 STOCK INCENTIVE PLAN

OGE Energy Corp. (the "Company") hereby awards, at target, to __________ (the "Participant") __ Performance Units pursuant to the OGE Energy Corp. 2013 Stock Incentive Plan (the "Plan"), the definitions and provisions of which are incorporated herein by reference.

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

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

2. Performance Goal Condition. The Performance Units are contingently awarded subject to the condition that the number of Performance Units, if any, earned by the Participant upon the expiration of the Award Cycle is dependent (in the manner hereinafter set forth) on the performance of the Company's total shareholder return relative to the total shareholder return of all of the companies (the "S&P Companies") comprising the Standard and Poor's 1500 Utilities Index as of __________ and __________ (or their successors from a merger or other combination with another company listed in such Index, but excluding any company subject to a Business Combination, as hereinafter defined on __________). Total shareholder return ("TSR") for any company, including the Company, shall include both price appreciation (depreciation) and cash dividends, shall be calculated in the same manner that Standard and Poor's calculated total return as of __________ and shall be measured by the company's total return that shareholders receive over the Award Cycle by investment at the first day of the Award Cycle.

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

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

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

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

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

For purposes of determining whether any of the S&P Companies is subject to a Business Combination on __________, a company shall be deemed subject to a Business Combination on __________, if such company is: (i) the subject of a tender offer or exchange offer by a third party seeking to acquire more than 20% of the outstanding voting securities of such company or (ii) a party to a merger, consolidation, share exchange or reorganization agreement or an agreement providing for the sale or disposition of all or substantially all of its assets.

3. Payout. Subject to Section 9 of the Plan, as soon as practicable following the end of the Award Cycle, the Committee shall evaluate the actual performance of the Performance Goal set forth in Section 2 hereof, shall certify in writing the extent to which such Performance Goal and other material terms of this award have been satisfied and shall determine the number, if any, of Performance Units that have been earned (the "Earned Performance Units"). The Committee shall then cause to be issued to the Participant (or, in the event of the Participant's death, to the Participant's beneficiary under the Plan) no later than __________: (i) a certificate for shares of Common Stock equal in number to the Earned Performance Units (disregarding any fraction) plus a cash payment equal to the amount of dividends that would have been declared during the Award Cycle on such number of shares of Common Stock being issued pursuant to this Section 3.

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

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

6. Taxes and Other Matter.

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

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

7. Other Condition. The award of Performance Units evidenced by this Agreement shall be subject to your acceptance of this Agreement.

OGE ENERGY CORP.

BY: ______________________________

Chairman of the Board and
Chief Executive Officer

ACCEPTED AND AGREED TO this _________ day of ______________________________

____
Participant

OGE ENERGY CORP.
FORM OF PERFORMANCE UNIT AGREEMENT
UNDER THE 2013 STOCK INCENTIVE PLAN

OGE Energy Corp. (the "Company") hereby awards, at target, to __________ (the "Participant") __ Performance Units pursuant to the OGE Energy Corp. 2013 Stock Incentive Plan (the "Plan"), the definitions and provisions of which are incorporated herein by reference.

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

1. Performance Units and Award Cycle. Each Performance Unit represents and is equal to the value of one share of Company Common Stock. Subject to the provisions of the Plan, the Performance Units awarded to the Participant may not be sold, assigned, transferred, pledged, hypothecated or otherwise encumbered or disposed of during the award cycle established with respect thereto beginning on January 1, 2015 and ending on December 31, 2017 (the "Award Cycle").

2. Performance Goal Condition. The Performance Units are contingently awarded subject to the condition that the number of Performance Units, if any, earned by the Participant upon the expiration of the Award Cycle is dependent (in the manner hereinafter set forth) on Utility EPS Growth during the Award Cycle. Utility EPS Growth shall mean the amount obtained by multiplying one-third times the percentage increase or decrease in Utility EPS for the year ended December 31, 2017 as compared to $1.46 for the year ended December 31, 2014. Utility EPS shall mean the sum of: (x) the Net Income as shown on the Statement of Income of Oklahoma Gas and Electric Company for the year ended December 31, 2017 plus (y) the Net Income of OGE Transmission Company as shown on the Statement of Income of OGE Transmission Company for the year ended December 31, 2017, divided by the same number of outstanding shares of common stock used in calculating consolidated diluted earnings per average common share from continuing operations of OGE Energy Corp., as reported on the Consolidated Statement of Income of OGE Energy Corp. for the year ended December 31, 2017. For purposes of the foregoing, all percentages shall be calculated to the nearest one-hundredth of one percent. The number of Performance Units earned for the Award Cycle shall be determined in accordance with the following chart:

UTILITY'S AVERAGE EARNINGS PER SHARE GROWTH	PERCENT OF TARGET PERFORMANCE UNITS EARNED
7.0%	200%
6.3%	180%
5.6%	160%
4.9%	140%
4.2%	120%
3.5%	100%
3.0%	87.5%
2.5%	75%
2.0%	62.5%
1.5%	50%
Below 1.5%	0%

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

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

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

3. Payout. Subject to Section 9 of the Plan, as soon as practicable following the end of the Award Cycle, the Committee shall evaluate the actual performance of the Performance Goal set forth in Section 2 hereof, shall certify in writing the extent to which such Performance Goal and other material terms of this award have been satisfied and shall determine the number, if any, of Performance Units that have been earned (the "Earned Performance Units"). The Committee shall then cause to be issued to the Participant (or, in the event of the Participant's death, to the Participant's beneficiary under the Plan) no later than March 15, 2018: (i) a certificate for shares of Common Stock equal in number to the Earned Performance Units (disregarding any fraction) plus a cash payment equal to the amount of dividends that would have been declared during the Award Cycle on such number of shares of Common Stock being issued pursuant to this Section 3.

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

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

6. Taxes and Other Matter.

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

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

7. Other Condition. The award of Performance Units evidenced by this Agreement shall be subject to your acceptance of this Agreement.

OGE ENERGY CORP.

BY: ____

Chairman of the Board and
Chief Executive Officer

ACCEPTED AND AGREED TO this _________ day of ______________________________

____
Participant

Exhibit 10.54

OGE ENERGY CORP.
FORM OF RESTRICTED STOCK UNITS AGREEMENT
UNDER THE 2013 STOCK INCENTIVE PLAN

OGE Energy Corp. (the "Company") hereby awards to [_________] (the "Participant") [________] Restricted Stock Units (the “Units”) pursuant to the OGE Energy Corp. 2013 Stock Incentive Plan (the "Plan"), the definitions and provisions of which are incorporated herein by reference.

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

1. Restrictions on Transfer and Restriction Periods.

(a) During the respective periods hereinafter described in Section 1(b) (the Restriction Periods”), the Units may not be sold, assigned, transferred, pledged, or otherwise encumbered by the Participant and shall be subject to a risk of forfeiture, except as hereinafter provided.

(b) The restrictions described above shall commence on the date of this Agreement (the “Grant Date”) and, except as provided in Section 1(d) or Section 2, shall lapse with respect to one-third (33.3%) of the Units on the first anniversary of the Grant Date, one-third (33.3%) of the Units on the second anniversary of the Grant Date and with respect to the remaining Units on the third anniversary of the Grant Date.

(c) The number of shares of Common Stock covered by this award is equal to the number of Units.

(d) Absent a prior forfeiture, each Unit subject to this Agreement shall vest and shall represent the right to receive one share of Common Stock, and related dividends as described below, upon the expiration of the Restriction Period applicable to such Unit or, if earlier, upon a Change of Control as defined in the Plan or upon a waiver of the restrictions applicable to such Unit as described below in Section 2. The date on which a Unit vests is hereinafter referred to as the "Vesting Date."

2. Termination of Service.

If the Participant has a Termination of Employment (as defined on the Plan), all Units which are then subject to the restrictions imposed by Section 1 shall be forfeited and of no further effect; provided, however, that if the Participant ceases employment by reason of Retirement (as defined in the Plan) or involuntary termination, the Compensation Committee (the “Compensation Committee”) of the Company’s Board of Directors may waive all remaining restrictions.

3. Vesting and Payout of Units.

As soon as practicable following the Vesting Date for one or more Units (the "Vested Units"), the Company shall cause to be delivered to the Participant: (i) a number of shares of Common Stock (less the number of shares, if any, withheld pursuant to Section 6(b) below) equal to the number of Vested Units in such manner as the Committee may deem appropriate, including book-entry or other electronic registration or issuance of one or more stock certificates and (ii) a lump sum cash payment equal to the amount of dividends that would have been declared, during the period from Grant Date through the Vesting Date(s), on the number of shares of Common Stock being issued under the preceding clause (i) of this Section 3.

4. Participant’s Rights.

The Participant acknowledges and agrees that the Units do not evidence, and do not entitle the Participant to, any rights of a shareholder of the Company.

5. Acceptance of Award.

By execution of this Agreement, the Participant accepts the award, acknowledges receipt of a copy of the Plan (a copy of which is attached as Annex I), and represents that the Participant is familiar with the terms and provisions thereof and agrees to be bound thereby. Participant further agrees to accept as binding, conclusive and final all decisions or interpretations of the Compensation Committee with respect to any questions arising under the Plan and this Agreement.

6. Taxes and Other Matters.

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

(b) Participant may elect to satisfy Participant's minimum tax withholding requirements upon expiration or lapsing of a Restriction Period, in whole or in part, by having the Company withhold shares of Common Stock having a fair market value equal to all or a portion of the amount so required to be withheld. The value of the shares to be withheld is to be based upon the same price of the shares that is utilized to determine the amount of withholding tax that the Participant owes. All elections under this Section 6(b) shall be (i) irrevocable and (ii) made electronically through the Company Stock Plan Services Administrator.

7. Other Condition.

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

Dated this __________ day of ______________________________.

OGE ENERGY CORP.

BY: ______________________________
Chairman of the Board and
Chief Executive Officer

ACCEPTED AND AGREED TO this __________ day of ______________________________

____
Participant

Exhibit 12.01

OGE Energy Corp.
Ratio of Earnings to Fixed Charges

Year ended December 31 *(In millions)*	**2015**	2014	2013	2012	2011
Earnings:					
Pre-tax income (A)	**$ 353.2**	$ 396.0	$ 422.2	$ 520.1	$ 524.3
Add: Fixed charges	**156.3**	153.9	157.2	174.4	161.8
Distributions received from equity method investment	**139.3**	143.7	51.7	—	—
Subtotal	**648.8**	**693.6**	**631.1**	**694.5**	**686.1**
Subtract:					
Allowance for borrowed funds used during construction	**4.2**	2.4	3.4	3.5	10.4
Other capitalized interest	**—**	—	2.0	4.5	8.7
Total earnings	**644.6**	691.2	625.7	686.5	667.0
Fixed Charges:					
Interest on long-term debt	**147.8**	144.6	147.6	163.4	154.8
Interest on short-term debt and other interest charges	**5.4**	6.2	5.3	8.7	5.2
Calculated interest on leased property	**3.1**	3.1	4.3	2.3	1.8
Total fixed charges	**$ 156.3**	$ 153.9	$ 157.2	$ 174.4	$ 161.8
Ratio of Earnings to Fixed Charges	**4.12**	4.49	3.98	3.94	4.12

(A) Excludes amounts attributable to income or loss from equity method investment.

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. 333-200178) 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 26, 2016, 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, 2015.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
February 26, 2016

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 on Form S-3ASR (No. 333-200178) and Registration Statement on Form S-3ASR (No. 333-188309), of our report dated February 17, 2016 relating to the combined and consolidated financial statements of Enable Midstream Partners, LP 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), appearing in this Annual Report on Form 10-K of OGE Energy Corp. for the year ended December 31, 2015.

/s/ Deloitte & Touche LLP

Houston, Texas
February 26, 2016

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, 2015; 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 SEAN TRAUSCHKE, STEPHEN E. MERRILL 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 25th day of February, 2016.

Sean Trauschke, Chairman, Principal Executive Officer and Director	/s/ Sean Trauschke
Frank A. Bozich, Director	/s/ Frank A. Bozich
James H. Brandi, Director	/s/ James H. Brandi
Luke R. Corbett, Director	/s/ Luke R. Corbett
John D. Groendyke, Director	/s/ John D. Groendyke
David L. Hauser, Director	/s/ David L. Hauser
Kirk Humphreys, Director	/s/ Kirk Humphreys
Robert O. Lorenz, Director	/s/ Robert O. Lorenz
Judy R. McReynolds, Director	/s/ Judy R. McReynolds
Sheila G. Talton, Director	/s/ Sheila G. Talton
Stephen E. Merrill, Principal Financial Officer	/s/ Stephen E. Merrill
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 25th day of February, 2016.

/s/ Kelly Hamilton-Coyer

By: Kelly Hamilton-Coyer

Notary Public

My commission expires:
July 6, 2017

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 26, 2016

/s/ Sean Trauschke

Sean Trauschke

Chairman of the Board, President and Chief Executive Officer

Exhibit 31.01

CERTIFICATIONS

I, Stephen E. Merrill, 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 26, 2016

/s/ Stephen E. Merrill

Stephen E. Merrill
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, 2015, 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 26, 2016

/s/ Sean Trauschke
Sean Trauschke
Chairman of the Board, President and Chief Executive Officer

/s/ Stephen E. Merrill
Stephen E. Merrill
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 Notes 14 and 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 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 Board of Directors of Enable GP, LLC and
Unitholders of Enable Midstream Partners, LP
Oklahoma City, Oklahoma

We have audited the accompanying consolidated balance sheets of Enable Midstream Partners, LP and subsidiaries (the "Partnership") as of December 31, 2015 and 2014, 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, 2015. 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. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, 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, 2015 and 2014, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, 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.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Partnership's internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 17, 2016 expressed an unqualified opinion on the Partnership's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 17, 2016

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of Enable GP, LLC and
Unitholders of Enable Midstream Partners, LP
Oklahoma City, Oklahoma

We have audited the internal control over financial reporting of Enable Midstream Partners, LP and subsidiaries (the "Partnership") as of December 31, 2015, based on criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Partnership'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 Partnership'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 by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel 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 the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the 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, the Partnership maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the combined and consolidated financial statements as of and for the year ended December 31, 2015 of the Partnership and our report dated February 17, 2016 expressed an unqualified opinion on those financial statements and included an explanatory paragraph regarding basis of presentation.

/s/ DELOITTE & TOUCHE LLP

Houston, Texas
February 17, 2016

ENABLE MIDSTREAM PARTNERS, LP
COMBINED AND CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31,		
	2015	2014	2013
	(In millions, except per unit data)		
Revenues (including revenues from affiliates (Note 14)):			
Product sales	$ 1,334	$ 2,300	$ 1,566
Service revenue	1,084	1,067	923
Total Revenues	2,418	3,367	2,489
Cost and Expenses (including expenses from affiliates (Note 14)):			
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	1,097	1,914	1,313
Operation and maintenance	419	420	358
General and administrative	103	107	71
Depreciation and amortization	318	276	212
Impairments (Note 8, Note 11)	1,134	8	12
Taxes other than income taxes	59	56	54
Total Cost and Expenses	3,130	2,781	2,020
Operating (Loss) Income	(712)	586	469
Other Income (Expense):			
Interest expense (including expenses from affiliates (Note 14))	(90)	(70)	(67)
Equity in earnings of equity method affiliates	29	20	15
Interest income—affiliated companies	—	—	9
Other, net	2	(1)	—
Total Other Income (Expense)	(59)	(51)	(43)
(Loss) Income Before Income Taxes	(771)	535	426
Income tax expense (benefit)	—	2	(1,192)
Net (Loss) Income	$ (771)	$ 533	$ 1,618
Less: Net (loss) income attributable to noncontrolling interest	(19)	3	3
Net (Loss) Income attributable to Enable Midstream Partners, LP	$ (752)	$ 530	$ 1,615
Limited partners' interest in net (loss) income attributable to Enable Midstream Partners, LP (Note 4)	$ (752)	530	$ 289
Basic and diluted (loss) earnings per common limited partner unit (Note 4)	$ (1.78)	$ 1.29	$ 0.74
Basic and diluted (loss) earnings per subordinated limited partner unit (Note 4)	$ (1.78)	$ 1.28	$ —
Basic and diluted weighted average number of outstanding common limited partner units (Note 4)	214	264	390
Basic and diluted weighted average number of outstanding subordinated limited partner units (Note 4)	208	148	—

See Notes to the Combined and Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
COMBINED AND CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Net (loss) income	$ (771)	$ 533	$ 1,618
Comprehensive (loss) income	(771)	533	1,618
Less: Comprehensive (loss) income attributable to noncontrolling interest	(19)	3	3
Comprehensive (loss) income attributable to Enable Midstream Partners, LP	$ (752)	$ 530	$ 1,615

See Notes to the Combined and Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED BALANCE SHEETS

	December 31, 2015	December 31, 2014
	(In millions, except units)	
Current Assets:		
Cash and cash equivalents	$ 4	$ 12
Accounts receivable	245	254
Accounts receivable—affiliated companies	21	27
Inventory	53	63
Gas imbalances	23	45
Other current assets	35	37
Total current assets	381	438
Property, Plant and Equipment:		
Property, plant and equipment	11,293	10,464
Less accumulated depreciation and amortization	1,162	882
Property, plant and equipment, net	10,131	9,582
Other Assets:		
Intangible assets, net	333	357
Goodwill	—	1,068
Investment in equity method affiliates	344	348
Other	49	44
Total other assets	726	1,817
Total Assets	$ 11,238	$ 11,837
Current Liabilities:		
Accounts payable	$ 248	$ 275
Accounts payable—affiliated companies	9	38
Short-term debt	236	253
Taxes accrued	30	23
Gas imbalances	25	13
Other	67	69
Total current liabilities	615	671
Other Liabilities:		
Accumulated deferred income taxes, net	8	9
Notes payable—affiliated companies	363	363
Regulatory liabilities	18	16
Other	20	27
Total other liabilities	409	415
Long-Term Debt	2,683	1,928
Commitments and Contingencies (Note 15)		
Partners' Capital:		
Common units (214,541,422 issued and outstanding at December 31, 2015 and 214,417,908 issued and outstanding at December 31, 2014, respectively)	3,714	4,353
Subordinated units (207,855,430 issued and outstanding at December 31, 2015 and December 31, 2014, respectively)	3,805	4,439
Total partners' capital attributable to Enable Midstream Partners, LP Partners' Capital	7,519	8,792
Noncontrolling interest	12	31
Total Partners' Capital	7,531	8,823
Total Liabilities and Partners' Capital	$ 11,238	$ 11,837

See Notes to the Combined and Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
COMBINED AND CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Cash Flows from Operating Activities:			
Net (loss) income	$ (771)	$ 533	$ 1,618
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depreciation and amortization	318	276	212
Deferred income taxes	(1)	1	(1,194)
Impairments	1,134	8	12
Loss on sale/retirement of assets	5	—	2
Equity in earnings of equity method affiliates, net of distributions	5	3	9
Equity based compensation	9	13	—
Amortization of debt costs and discount (premium)	(2)	(1)	—
Changes in other assets and liabilities:			
Accounts receivable, net	9	52	(81)
Accounts receivable—affiliated companies	6	1	(4)
Inventory	10	7	(6)
Gas imbalance assets	22	(35)	2
Income taxes receivable	—	—	19
Other current assets	2	17	15
Other assets	(4)	5	(1)
Accounts payable	—	(138)	62
Accounts payable—affiliated companies	(29)	(2)	3
Gas imbalance liabilities	12	—	—
Other current liabilities	6	29	(2)
Other liabilities	(5)	—	(18)
Net cash provided by operating activities	726	769	648
Cash Flows from Investing Activities:			
Capital expenditures	(869)	(837)	(573)
Acquisitions, net of cash acquired	(80)	—	—
Proceeds from sale of assets	3	13	—
Decrease in notes receivable—affiliated companies	—	—	434
Return of investment in equity method affiliates	8	198	—
Investment in equity method affiliates	(8)	(189)	—
Other, net	—	—	(1)
Net cash used in investing activities	(946)	(815)	(140)
Cash Flows from Financing Activities:			
Repayment of long term debt	—	(1,500)	—
Proceeds from long term debt, net of issuance costs	450	1,635	1,046
Proceeds from revolving credit facility	585	122	1,126
Repayment of revolving credit facility	(275)	(495)	(754)
Increase (decrease) in short-term debt	(17)	253	—
Decrease of notes payable—affiliated companies	—	—	(1,542)
Repayment of advance with affiliated companies	—	—	(136)
Capital contributions from partners	—	464	43
Distributions to partners	(531)	(529)	(183)
Net cash provided by (used in) financing activities	212	(50)	(400)
Net Increase (Decrease) in Cash and Cash Equivalents	(8)	(96)	108
Cash and Cash Equivalents at Beginning of Period	12	108	—
Cash and Cash Equivalents at End of Period	$ 4	$ 12	$ 108

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									
	Common Units		Subordinated Units		Parent Net Investment	Accumulated Other Comprehensive Loss	Total Enable Midstream Partners, LP Partners' Capital	Noncontrolling Interest	Total Partners' Capital
	Units	Value	Units	Value	Value	Value	Value	Value	Value
					(In millions)				
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 5)	—	—	—	—	(295)	6	(289)	—	(289)
Balance as of April 30, 2013	—	$ —	—	$ —	$ 4,252	$ —	$ 4,252	$ 6	$ 4,258
Conversion to a limited partnership	227	4,252	—	—	(4,252)	—	—	—	—
Issuance of units upon acquisition of Enogex on May 1, 2013	163	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	390	$ 8,148	—	$ —	$ —	$ —	$ 8,148	$ 33	$ 8,181
Conversion to subordinated units	(208)	(4,372)	208	4,372	—	—	—	—	—
Net income	—	349	—	181	—	—	530	3	533
Issuance of Offering common units	25	464	—	—	—	—	464	—	464
Issuance of common units upon interest acquisition of SESH	6	161	—	—	—	—	161	—	161
Distributions to partners	—	(410)	—	(114)	—	—	(524)	(5)	(529)
Equity based compensation	1	13	—	—	—	—	13	$ —	13
Balance as of December 31, 2014	214	$ 4,353	208	$ 4,439	$ —	$ —	$ 8,792	$ 31	$ 8,823
Net loss	—	(379)	—	(373)	—	—	(752)	(19)	(771)
Issuance of common units upon interest acquisition of SESH	—	1	—	—	—	—	1	—	1
Distributions to partners	—	(270)	—	(261)	—	—	(531)	—	(531)
Equity based compensation	—	9	—	—	—	—	9	—	$ 9
Balance as of December 31, 2015	214	$ 3,714	208	$ 3,805	$ —	$ —	$ 7,519	$ 12	$ 7,531

See Notes to the Combined and Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
NOTES TO THE COMBINED AND CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Organization

Enable Midstream Partners, LP (Partnership) is a Delaware 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 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 reportable segments: (i) Gathering and Processing, which primarily provides natural gas gathering, processing and fractionation services and crude oil gathering for our producer customers, and (ii) Transportation and Storage, which provides interstate and intrastate natural gas pipeline transportation and storage services primarily to natural gas producers, utilities and industrial customers. The natural gas gathering and processing assets are located in five states and serve natural gas production in the Anadarko, Arkoma and Ark-La-Tex basins. This segment also includes a 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.

The Partnership is controlled equally by CenterPoint Energy and OGE Energy, who each have 50% of the management rights of Enable GP. Enable GP was established by CenterPoint Energy and OGE Energy to govern the Partnership and has no other operating activities. Enable GP is governed by a board made up of an equal number of representatives designated by each of CenterPoint Energy and OGE Energy, along with the Partnership's Chief Executive Officer and the independent board members CenterPoint Energy and OGE Energy mutually agreed 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, respectively. CenterPoint Energy and OGE Energy also own a 40% and 60% interest, respectively, in the incentive distribution rights held by Enable GP.

At December 31, 2015, CenterPoint Energy held approximately 55.4% of the limited partner interests in the Partnership, or 94,151,707 common units and 139,704,916 subordinated units, and OGE Energy held approximately 26.3% of the limited partner interests in the Partnership, or 42,832,291 common units and 68,150,514 subordinated units. 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 (Enable GP) on an annual or continuing basis and may not remove Enable GP without at least a 75% vote by all unitholders, including all units held by the Partnership's limited partners, and Enable GP and its affiliates, voting together as a single class.

Upon conversion to a limited partnership on May 1, 2013, the Partnership's earnings are generally no longer subject to income tax (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiary, Enable Midstream Services) 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 and taxes associated with the Partnership's corporate subsidiary, Enable Midstream Services). See Note 16 for further discussion of the Partnership's income taxes.

Prior to May 1, 2013, the financial statements of the Partnership include EGT, MRT and the non-rate regulated natural gas gathering, processing and treating operations, which were under common control by CenterPoint Energy, and a 50% interest in SESH. Through the Partnership's 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 notes payable—affiliated companies 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 9. 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 Enable GP. 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 formation of the Partnership and the acquisition of Enogex. See Note 3 for further discussion of the acquisition of Enogex. For the period from May 1, 2013 through May 29, 2014, the financial statements reflect a 24.95% interest in SESH. For the period of May 30, 2014 through June 29, 2015, the financial statements reflect a 49.90% interest in SESH. On June 12, 2015, CenterPoint Energy exercised its put right with respect to a 0.1% interest in SESH. Pursuant to the put right, on June 30, 2015, CenterPoint Energy contributed its remaining 0.1% interest in SESH to the Partnership in exchange for 25,341 common units representing limited partner interests in the Partnership. As of December 31, 2015, the Partnership owned a 50% interest in SESH. See Note 9 for further discussion of SESH.

In addition, as of December 31, 2015 and 2014, as a result of the acquisition of Enogex on May 1, 2013, the Partnership held a 50% ownership interest in Atoka. At December 31, 2015 and 2014, the Partnership consolidated Atoka in its Combined and Consolidated Financial Statements as EOIT acted as the managing member of Atoka and had control over the operations of Atoka.

On April 16, 2014, the Partnership completed the Offering of 25,000,000 common units, representing limited partner interests in the Partnership, at a price to the public of $20.00 per common unit. The Partnership received net proceeds of $464 million from the sale of the common units, after deducting underwriting discounts and commissions, the structuring fee and offering expenses. In connection with the Offering, underwriters exercised their option to purchase 3,750,000 additional common units, which were fulfilled with units held by ArcLight. As a result, the Partnership did not receive any proceeds from the sale of common units pursuant to the exercise of the underwriters' option to purchase additional common units. The exercise of the underwriters' option to purchase additional common units did not affect the total number of units outstanding or the amount of cash needed to pay the minimum quarterly distribution on all outstanding units. The Partnership retained the net proceeds of the Offering for general partnership purposes, including the funding of expansion capital expenditures, and to pre-fund demand fees expected to be incurred over the next three years relating to certain expiring transportation and storage contracts. In connection with the Offering, 139,704,916 of CenterPoint Energy's common units and 68,150,514 of OGE Energy's common units were converted into subordinated units.

Basis of Presentation

The accompanying combined and consolidated financial statements and related notes of the Partnership have been prepared pursuant to the rules and regulations of the SEC and GAAP. 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.

The 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 the Partnership’s historical 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.

For a description of the Partnership’s reportable segments, see Note 18.

Use of Estimates

The preparation of financial statements in conformity with GAAP 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.

Revenue Recognition

The Partnership generates the majority of its revenues from midstream energy services, including natural gas gathering, processing, transportation and storage and crude oil gathering. The Partnership performs these services under various contractual arrangements, which include fee-based contract arrangements and arrangements pursuant to which it purchases and resells commodities in connection with providing the related service and earns a net margin for its fee. While the Partnership's transactions vary in form, the essential element of each transaction is the use of its assets to transport a product or provide a processed product to a customer. The Partnership reflects revenue as Product sales and Service revenue on the Combined and Consolidated Statements of Income as follows:

Product sales: Product sales represent the sale of natural gas, NGLs, crude oil and condensate where the product is purchased and used in connection with providing the Partnership's midstream services.

Service revenue: Service revenue represents all other revenue generated as a result of performing the Partnership's midstream services.

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 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 and crude oil gathering 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 $17 million and $18 million of deferred revenues on the Consolidated Balance Sheets at December 31, 2015 and 2014, 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 years ended December 31, 2015, 2014 and 2013, one third party purchased approximately 18%, 21% and 30%, respectively, of the NGLs delivered off our system, which accounted for approximately $108 million, $235 million and $232 million, or 4%, 7% and 9%, respectively, of total revenue. Other than revenues from affiliates discussed in Note 14, there are no other revenue concentrations with individual customers in the years ended December 31, 2015, 2014, and 2013.

Natural Gas and Natural Gas Liquids Purchases

Cost of natural gas and natural gas liquids represents cost of our natural gas and natural gas liquids purchased exclusive of depreciation, Operation and maintenance and General and administrative expenses and consists primarily of product and fuel costs. 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 Consolidated Balance Sheets and in Cost of natural gas and natural gas liquids, excluding Depreciation and amortization on the Combined and Consolidated Statements of Income.

Operation and Maintenance and General and Administrative Expense

Operation and maintenance expense represents the cost of our service related revenues and consists primarily of labor expenses, lease costs, utility costs, insurance premiums and repairs and maintenance expenses directly related with the operations of assets. General and administrative expense represents cost incurred to manage the business. This expense includes cost of general corporate services, such as treasury, accounting, legal, information technology and human resources and all other expenses necessary or appropriate to the conduct of business. Any Operation and maintenance expense and General and administrative expense associated with product sales is immaterial.

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, 2015 or 2014.

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.

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

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 taxes associated with the Partnership's corporate subsidiary, Enable Midstream Services) and are taxable at the individual partner level. For more information, see Note 16.

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 Consolidated Balance Sheets have $4 million and $12 million of cash and cash equivalents as of December 31, 2015 and 2014, 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 at least quarterly, 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, 2015 and 2014.

Inventory

Materials and supplies inventory is valued at cost and is subsequently recorded at the lower of cost or market. During the years ended December 31, 2014 and 2013, the Partnership recorded write-downs to market value related to materials and supplies inventory disposed or identified as excess or obsolete of $9 million and $2 million, respectively. There were no material write-downs related to materials and supplies inventory for the year ended December 31, 2015. 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 Consolidated Balance Sheets when installed.

Natural gas inventory is held, through the Transportation and Storage 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 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 years ended December 31, 2015, 2014 and 2013, the Partnership recorded write-downs to market value related to natural gas and natural gas liquids inventory of $13 million, $4 million and $4 million, respectively. The cost of gas associated with sales of natural gas and natural gas liquids inventory is presented in Cost of natural gas and natural gas liquids, excluding depreciation and amortization on the Combined and Consolidated Statements of Income.

	December 31,	
	2015	2014
	(In millions)	
Materials and supplies	$ 34	$ 39
Natural gas and natural gas liquids inventories	19	24
Total	$ 53	$ 63

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 natural gas 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. Newly constructed plant is added to plant balances at cost which includes contracted services, direct labor, materials, overhead, transportation costs and capitalized interest. Replacements of units of property are capitalized as plant. For assets that belong to a common plant account, the replaced plant is removed from plant balances and charged to Accumulated Depreciation. For assets that do not belong to a common plant account, the replaced plant is removed from plant balances with the related accumulated depreciation and the remaining balance net of any salvage proceeds is recorded as a loss in the Consolidated Statements of Income as Operation and Maintenance Expense. The Partnership expenses repair and maintenance costs as incurred. Repair, removal and maintenance costs are included in the Consolidated Statements of Income as Operation and Maintenance Expense.

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. For more information, see Note 11.

The Partnership assesses its goodwill for impairment annually on October 1st, or more frequently if events or changes in circumstances indicate that the carrying value of goodwill may not be recoverable. Goodwill is assessed for impairment 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 segment level at the operating segment level. For more information, see Note 8.

Regulatory Assets and Liabilities

The Partnership applies the guidance for accounting for regulated operations to portions of the Transportation and Storage 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, 2015 and 2014, these removal costs of $18 million and $16 million, respectively, are classified as regulatory liabilities in the 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. Capitalized interest represents the approximate net composite interest cost of borrowed funds used for construction. Interest and AFUDC are capitalized as a component of projects under construction and will be amortized over the assets' estimated useful lives. During the years ended December 31, 2015, 2014 and 2013, the Partnership capitalized interest and AFUDC of $10 million, $8 million and $7 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, financial futures and swaps to mitigate the impact of changes in commodity prices on its operating results and cash flows. Such derivatives are recognized in the Partnership's Consolidated Balance Sheets at their fair value unless the Partnership elects hedge accounting or 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.

Equity Based Compensation

The Partnership awards equity based compensation to officers, directors and employees under the Long Term Incentive Plan. All equity based awards to officers, directors and employees under the Long Term Incentive Plan, including grants of phantom units, performance units, and restricted units are recognized in the Combined and Consolidated Statements of Income based on their fair values. The fair value of the phantom units and restricted units are based on the closing market price of the Partnership's common unit on the grant date. The fair value of the performance units is estimated on the grant date using a lattice-based valuation model that factors in information, including the expected distribution 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 phantom unit and restricted unit awards is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over a vesting period. The vesting of the performance unit awards is also contingent upon the probable outcome of the market condition. Depending on forfeitures and actual vesting, the compensation expense recognized related to the awards could increase or decrease.

Reverse Unit Split

On March 25, 2014, the Partnership effected a 1 for 1.279082616 reverse unit split. All unit and per unit amounts presented within the combined and consolidated financial statements reflect the effects of the reverse unit split.

Second Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP

On April 16, 2014, in connection with the closing of the Offering of the Partnership, the Partnership amended and restated its First Amended and Restated Agreement of Limited Partnership to remove certain provisions that expired upon completion of the Offering. Following the Offering, ArcLight no longer has 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.

(2) New Accounting Pronouncements

Revenue from Contracts with Customers

In May 2014, FASB issued ASU No. 2014-09, "Revenue from Contracts with Customers," which supersedes the revenue recognition requirements in "Revenue Recognition (Topic 605)," and requires entities to recognize revenue in a way that depicts the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled to in exchange for those goods or services. ASU 2014-09 is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016, and is to be applied retrospectively, with early application not permitted.

In August 2015, FASB issued ASU No. 2015-14, "Revenue from Contracts with Customers (Topic 606)—Deferral of the Effective Date," which deferred the effective date of ASU 2014-09 by one year to December 15, 2017 for annual reporting periods beginning after that date. The FASB also proposed permitting early adoption of the standard, but not before the original effective date of December 15, 2016. The Partnership is currently evaluating the impact, if any, the adoption of this standard will have on our Combined and Consolidated Financial Statements and related disclosures.

Consolidation

In February 2015, FASB issued ASU No. 2015-02, “Consolidation,” to improve consolidation guidance for certain types of legal entities. The guidance modifies the evaluation of whether limited partnerships and similar legal entities are variable interest entities (VIEs) or voting interest entities, eliminates the presumption that a general partner should consolidate a limited partnership, affects the consolidation analysis of reporting entities that are involved with VIEs, particularly those that have fee arrangements and related party relationships, and provides a scope exception from consolidation guidance for certain money market funds. These provisions are effective for annual reporting periods beginning after December 15, 2015, and interim periods within those annual periods, with early adoption permitted. These provisions may also be adopted retrospectively in previously issued financial statements for one or more years with a cumulative-effect adjustment to partners’ capital as of the beginning of the first year restated. The Partnership does not expect the adoption of this standard will have a material impact on our Combined and Consolidated Financial Statements and related disclosures.

Presentation of Debt Issuance Costs

In April 2015, FASB issued ASU No. 2015-03, "Simplifying the Presentation of Debt Issuance Costs." This standard amends existing guidance to require the presentation of debt issuance costs in the balance sheet as a deduction from the carrying amount of the related debt liability instead of a deferred charge. It is effective for annual reporting periods beginning after December 15, 2015, but early adoption is permitted. As of December 31, 2015 and 2014, the Partnership had unamortized debt expense of $12 million and $13 million, respectively, which would have been classified as a reduction of long-term debt in our Consolidated Balance Sheets had we adopted this standard in the fourth quarter of 2015. The Partnership will adopt ASU No. 2015-03 in the first quarter of 2016 and it will be applied retrospectively to each period presented in the Combined and Consolidated Financial Statements.

In August 2015, the FASB issued ASU No. 2015-15, "Interest—Imputation of Interest: Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements—Amendments to SEC Paragraphs Pursuant to Staff Announcement at June 18, 2015 EITF Meeting." This ASU adds SEC paragraphs pursuant to the SEC Staff Announcement at the June 18, 2015, Emerging Issues Task Force meeting about the presentation and subsequent measurement of debt issuance costs associated with line-of-credit arrangements to this topic. Given the absence of authoritative guidance within ASU 2015-03 for debt issuance costs related to line-of-credit arrangements, the SEC staff would not object to an entity deferring and presenting debt issuance costs as an asset and subsequently amortizing the deferred debt issuance costs ratably over the term of the line-of-credit arrangement, regardless of whether there are any outstanding borrowings on the line-of-credit arrangement. The Partnership has elected to continue to carry debt issuance costs related to line-of-credit arrangements as an asset and amortize the deferred debt issuance costs over the term of the related line-of-credit arrangement. The Partnership will adopt the amendment in the first quarter of 2016 and has determined the adoption of ASU No. 2015-15 will have no impact on our Combined and Consolidated Financial Statements and related disclosures.

Customer's Accounting for Fees Paid in a Cloud Computing Arrangement

In April 2015, the FASB issued ASU No. 2015-05, "Customer's Accounting for Fees Paid in a Cloud Computing Arrangement." This standard provides guidance to customers about whether a cloud computing arrangement includes a software license. If a cloud computing arrangement includes a software license, the customer should account for the software license element of the arrangement consistent with the acquisition of other software licenses. If a cloud computing arrangement does not include a software license, the customer should account for the arrangement as a service contract. The new guidance does not change the accounting for a customer's accounting for service contracts. ASU No. 2015-05 is effective for interim and annual reporting periods beginning after December 15, 2015. The Partnership will adopt the amendment in the first quarter of 2016 and has determined the adoption of ASU No. 2015-05 will have no impact on our Combined and Consolidated Financial Statements and related disclosures.

Simplifying the Measurement of Inventory

In July 2015, the FASB issued ASU No. 2015-11, "Simplifying the Measurement of Inventory." Under this ASU, inventory will be measured at the “lower of cost and net realizable value,” and options that currently exist for “market value” will be eliminated. The ASU defines net realizable value as the “estimated selling prices in the ordinary course of business, less reasonably predictable costs of completion, disposal, and transportation.” No other changes were made to the current guidance on inventory measurement. ASU 2015-11 is effective for interim and annual periods beginning after December 15, 2016. Early application is permitted and should be applied prospectively. The Partnership will adopt ASU No. 2015-11 in the first quarter of 2016 and has determined the amendment will have no impact to our Combined and Consolidated Financial Statements and related disclosures.

Simplifying the Accounting for Measurement-Period Adjustments

In September 2015, the FASB issued ASU No. 2015-16, "Business Combinations—Simplifying the Accounting for Measurement-Period Adjustments." Under this ASU, acquirers are required to record, in the same period's financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. Acquirers are required to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. ASU 2015-16 is effective for interim and annual periods beginning after December 15, 2016. The amendments in this update should be applied prospectively to adjustments to provisional amounts that occur after the effective date with earlier application permitted for financial statements that have not been issued. This amendment has no impact to our current Combined and Consolidated Financial Statements, but could affect future disclosures.

Balance Sheet Classification of Deferred Taxes

In November 2015, the FASB issued ASU No. 2016-17, "Income Taxes—Balance Sheet Classification of Deferred Taxes." This ASU eliminates the requirement to present deferred tax liabilities and assets as current and non-current in a classified balance sheet. Instead, all deferred tax assets and liabilities will be classified as non-current. ASU 2015-17 is effective for all interim and annual periods beginning after December 16, 2015 and early application is permitted. The amendments in this update may be applied either prospectively to all deferred tax liabilities and assets or retrospectively to all periods presented. The Partnership does not expect the adoption of this standard will have a material impact on our Combined and Consolidated Financial Statements and related disclosures.

(3) Acquisitions

Monarch

On April 22, 2015, Enable entered into an agreement with Monarch Natural Gas, LLC, pursuant to which the Partnership agreed to acquire approximately 106 miles of gathering pipeline, approximately 5,000 horsepower of associated compression, right-of-ways and certain other midstream assets that provide natural gas gathering services in the Greater Granite Wash area of Texas. The transaction closed on May 1, 2015. The aggregate purchase price for this transaction was approximately $80 million, which was funded from cash generated from operations and borrowings under our Revolving Credit Facility.

The acquisition was accounted for as a business combination. During the third quarter of 2015, the Partnership, with the assistance of a third-party valuation expert, finalized the purchase price allocation as of May 1, 2015.

Purchase price allocation (in millions):		
Property, plant and equipment	$	51
Intangibles		10
Goodwill		19
Total	$	80

The Partnership recognized intangible assets related to customer relationships. The acquired intangible assets will be amortized on a straight-line basis over the estimated customer contract life of approximately 15 years. Goodwill recognized from the acquisition primarily relates to the value created from additional growth opportunities and greater operating leverage in the Anadarko Basin. See Note 8 for further information related to the Partnership's goodwill impairment. The Partnership incurred less than $1 million of acquisition costs associated with this transaction, which are included in General and administrative expense in the Combined and Consolidated Statements of Income.

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 was 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.

On May 1, 2013, in accordance with the MFA, CenterPoint Energy, OGE Energy, and ArcLight received 227,508,825 common units, 110,982,805 common units, and 51,527,730 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, for OGE Energy only, 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 were the historical and current year forecasted cash flows and market multiple. The primary inputs for the income approach were forecasted cash flows and the discount rate. The primary inputs for the cost approach were costs for similar assets and ages of the assets. All fair value measurements of assets acquired and liabilities assumed were based on a combination of inputs that were not observable in the market and thus represented 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.

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 the 100% interest in Enogex as of May 1, 2013 and is reconciled to the consideration transferred by the Partnership:

	Amounts Recognized as of May 1, 2013
	(In millions)
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 the Partnership included in the Partnership's Combined and Consolidated Statement of Income for the period from May 1, 2013 through December 31, 2013, before eliminations, are as follows (in millions):

Revenues	$ 1,406
Operating income	92
Net income	77
Net income attributable to Enable Midstream Partners, LP	74

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 pro forma results of operations in the combined entity had the acquisition of Enogex been completed on January 1, 2012 are as follows:

	Year ended December 31,	
	2013	2012
	(In millions)	
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 consolidated 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) Earnings Per Limited Partner Unit

Limited partners' interest in net (loss) income attributable to the Partnership and basic and diluted earnings per unit reflect net (loss) income attributable to the Partnership for periods subsequent to its formation as a limited partnership on May 1, 2013, as no limited partner units were outstanding prior to this date.

Basic and diluted earnings per limited partner unit is calculated by dividing the limited partners' interest in net (loss) income by the weighted average number of limited partner units outstanding during the period. Any common units issued during the period are included on a weighted average basis for the days in which they were outstanding. The dilutive effect of the unit-based awards discussed in Note 17 was less than $0.01 per unit during the years ended December 31, 2015 and 2014.

The following table illustrates the Partnership's calculation of earnings (loss) per unit for common and subordinated limited partner units:

	Year Ended December 31,		
	2015	2014	2013
	(In millions, except per unit data)		
Net (loss) income attributable to Enable Midstream Partners, LP	$ (752)	$ 530	$ 1,615
Less general partner interest in net (loss) income	—	—	—
Limited partner interest in net (loss) income attributable to Enable Midstream Partners, LP	$ (752)	$ 530	$ 1,615
Net (loss) income allocable to common units	$ (381)	$ 339	$ 289
Net (loss) income allocable to subordinated units	(371)	191	—
Limited partner interest in net (loss) income attributable to Enable Midstream Partners, LP	$ (752)	$ 530	$ 289
Basic and diluted weighted average number of outstanding limited partner units			
Common units	214	264	390
Subordinated units	208	148	—
Total	422	412	390
Basic and diluted (loss) earnings per limited partner unit			
Common units	$ (1.78)	$ 1.29	$ 0.74
Subordinated units	$ (1.78)	$ 1.28	$ —

(5) Enable Midstream Partners, LP Parent Net Equity and Partners' Capital

Prior to May 1, 2013, Enable Midstream Partners, LP Parent Net Equity 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 9)		(197)
Increase in Notes payable-affiliated companies		(143)
Decrease in Notes receivable-affiliated companies		(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. On February 14, 2014, May 14, 2014 and August 14, 2014, the Partnership distributed $114 million, $155 million and $22 million to the unitholders of record as of January 1, 2014, April 1, 2014, and April 1, 2014, respectively in accordance with the Partnership's First Amended and Restated Agreement of Limited Partnership.

The Partnership's Second Amended and Restated Agreement of Limited Partnership requires that, within 45 days subsequent to the end of each quarter, the Partnership distribute all of its available cash (as defined in the Second Amended and Restated Agreement of Limited Partnership) to unitholders of record on the applicable record date. The Partnership did not make distributions for the period that began on April 1, 2014 and ended on April 15, 2014, the day prior to the closing of the Offering, other than the required distributions to CenterPoint Energy, OGE Energy, and ArcLight under the First Amended and Restated Agreement of Limited Partnership.

We paid or have authorized payment of the following quarterly cash distributions under the Second Amended and Restated Agreement of Limited Partnership during 2015 and 2014 (in millions, except for per unit amounts):

Quarter Ended	Record Date	Payment Date	Per Unit Distribution		Total Cash Distribution	
December 31, 2015 (1)	February 2, 2016	February 12, 2016	$	0.318	$	134
September 30, 2015	November 3, 2015	November 13, 2015		0.318		134
June 30, 2015	August 3, 2015	August 13, 2015		0.316		134
March 31, 2015	May 5, 2015	May 15, 2015		0.3125		132
December 31, 2014	February 4, 2015	February 13, 2015		0.30875		130
September 30, 2014	November 4, 2014	November 14, 2014		0.3025		128
June 30, 2014 (2)	August 4, 2014	August 14, 2014		0.2464		104

(1) The board of directors of Enable GP declared this $0.318 per common unit cash distribution on January 22, 2016, to be paid on February 12, 2016, to unitholders of record at the close of business on February 2, 2016.

(2) The quarterly distribution for three months ended June 30, 2014 was prorated for the period beginning immediately after the closing of the Partnership's Offering, April 16, 2014 through June 30, 2014.

General Partner Interest and Incentive Distribution Rights

Enable GP owns a non-economic general partner interest in the Partnership and thus will not be entitled to distributions that the Partnership makes prior to the liquidation of the Partnership in respect of such general partner interest. Enable GP currently holds incentive distribution rights that entitle it to receive increasing percentages, up to a maximum of 50.0%, of the cash the Partnership distributes from operating surplus in excess of $0.330625 per unit per quarter. The maximum distribution of 50.0% does not include any distributions that Enable GP or its affiliates may receive on common units or subordinated units that they own.

Subordinated Units

All subordinated units are held by CenterPoint Energy and OGE Energy. These units are considered subordinated because during the subordination period, the common units will have the right to receive distributions of available cash from operating surplus each quarter in an amount equal to $0.2875 per common unit, which amount is defined in the partnership agreement as the minimum quarterly distribution, plus any arrearages in the payment of the minimum quarterly distribution on the common units from prior quarters, before any distributions of available cash from operating surplus may be made on the subordinated units. These units are deemed “subordinated” because for a period of time, referred to as the subordination period, the subordinated units will not be entitled to receive any distributions until the common units have received the minimum quarterly distribution plus any arrearages from prior quarters. Furthermore, no arrearages will be paid on the subordinated units.

Subordination Period

The subordination period began on the closing date of the Offering and will extend until the first business day following the distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equal to or exceeding $1.15 per unit (the annualized minimum quarterly distribution) for each of the three consecutive, non-overlapping four-quarter periods immediately preceding June 30, 2017. Also, if the Partnership has paid distributions of available cash from operating surplus on each of the outstanding common units and subordinated units equal to or exceeding $1.725 per unit (150 percent of the annualized minimum quarterly distribution) and the related distribution on the incentive distribution rights, for any four-consecutive-quarter period ending on or after June 30, 2015, the subordination period will terminate.

(6) Property, Plant and Equipment

Property, plant and equipment includes the following:

	Weighted Average Useful Lives (Years)	December 31, 2015	December 31, 2014
		(In millions)	
Property, plant and equipment, gross:			
Gathering and Processing	33	$ 6,478	$ 5,560
Transportation and Storage	36	4,444	4,300
Construction work-in-progress		371	604
Total		$ 11,293	$ 10,464
Accumulated depreciation:			
Gathering and Processing		510	343
Transportation and Storage		652	539
Total accumulated depreciation		1,162	882
Property, plant and equipment, net		$ 10,131	$ 9,582

The Partnership recorded depreciation expense of $291 million, $249 million and $194 million during the years ended December 31, 2015, 2014 and 2013, respectively.

(7) Intangible Assets, Net

Prior to May 1, 2013, the Partnership did not have any intangible assets. The Partnership has $405 million as of December 31, 2015, in intangible assets associated with customer relationships due to the acquisition of Enogex and Monarch Natural Gas, LLC.

Intangible assets consist of the following:

	December 31,	
	2015	2014
	(In millions)	
Customer relationships:		
Total intangible assets	$ 405	$ 401
Accumulated amortization	72	45
Net intangible assets	$ 333	$ 356

The Partnership determined that intangible assets related to customer relationships have a weighted average useful life of 15 years. Intangible assets do not have any significant residual value or renewal options of existing terms. There are no intangible assets with indefinite useful lives.

The Partnership recorded amortization expense of $27 million, $27 million and $18 million during the years ended December 31, 2015, 2014 and 2013, respectively. The following table summarizes the Partnership's expected amortization of intangible assets for each of the next five years:

	2016	2017	2018	2019	2020
			(In millions)		
Expected amortization of intangible assets	$ 27	$ 27	$ 27	$ 27	$ 27

(8) Goodwill

For the periods ended prior to September 30, 2015, the goodwill associated with the gathering and processing reportable segment is primarily related to the acquisitions of Enogex, Waskom and Monarch. The Partnership recognized $438 million of goodwill as a result of the acquisition of Enogex, which occurred at the time of the formation of the Partnership in 2013. The $579 million of goodwill associated with the transportation and storage reportable segment is related to the original acquisitions of EGT and MRT in 1997 by predecessors of the Partnership. The Partnership tests its goodwill for impairment annually on October 1st, or more frequently if events or changes in circumstances indicate that the carrying value of goodwill may not be recoverable. Goodwill is assessed for impairment by comparing the fair value of the reporting unit with its book value, including goodwill. Subsequent to the completion of the October 1, 2014 annual test and previous interim assessment as of December 31, 2014, the crude oil and natural gas industry was impacted by further commodity price declines, which consequently resulted in decreased producer activity in certain regions in which the Partnership operates. Due to the continuing commodity price declines, the resulting decreases in forward commodity prices and forecasted producer activities, and an increase in the weighted average cost of capital, the Partnership determined that the impact on our forecasted discounted cash flows for our gathering and processing and transportation and storage reportable segments would be significantly reduced. As a result, when the Partnership performed the first step of our annual goodwill impairment analysis as of October 1, 2015, we determined that the carrying value of the gathering and processing and transportation and storage reportable segments exceeded fair value. The Partnership completed the second step of the goodwill impairment analysis by comparing the implied fair value of the reporting unit to the carrying amount of that goodwill and determined that goodwill was completely impaired in the amount of $1,087 million, which is included in Impairments on the Combined and Consolidated Statements of Income for the year ended December 31, 2015.

The change in carrying amount of goodwill in each of our reportable segments is as follows:

	Gathering and Processing	Transportation and Storage	Total
		(in millions)	
Balance as of December 13, 2013	$ 489	$ 579	$ 1,068
Balance as of December 31, 2014	489	579	1,068
Acquisition of Monarch	19	—	19
Goodwill impairment	(508)	(579)	(1,087)
Balance as of December 31, 2015	$ —	$ —	$ —

(9) 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 286-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.

For the period May 1, 2013 through May 29, 2014, the Partnership held a 24.95% interest in SESH, which is accounted for as an investment in equity method affiliates, and CenterPoint Energy indirectly owned a 25.05% interest in SESH. Pursuant to the MFA, that interest could be contributed to the Partnership 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. On May 13, 2014, CenterPoint Energy exercised its put right with respect to a 24.95% interest in SESH. Pursuant to the put right, on May 30, 2014, CenterPoint Energy contributed a 24.95% interest in SESH to the Partnership in exchange for 6,322,457 common units representing limited partner interests in the Partnership, which had a fair value of $161 million based upon the closing market price of the Partnership's common units. For the period from May 30, 2014 through June 29, 2015, the Partnership held a 49.90% interest in SESH. On June 12, 2015, CenterPoint Energy exercised its put right with respect to its remaining 0.1% interest in SESH. Pursuant to the put right, on June 30, 2015, CenterPoint Energy contributed a 0.1% interest in SESH to the Partnership in exchange for 25,341 common units representing limited partner interests in the Partnership, which had a fair value of $1 million based upon the closing market price of the Partnership's common units. Spectra Energy Partners, LP owns the remaining 50% interest in SESH. Pursuant to the terms of the SESH LLC Agreement, if, at any time, CenterPoint Energy has a right to receive less than 50% of our distributions through its limited partner interest in the Partnership and its economic interest in Enable GP, or does not have the ability to exercise certain control rights, Spectra Energy Partners, LP could have the right to purchase our interest in SESH at fair market value. As of December 31, 2015, the Partnership owned a 50% interest in SESH.

In connection with CenterPoint Energy's exercise of its put right with respect to its 24.95% interest in SESH, the parties agreed to allocate the distributions for the quarter ended June 30, 2014 on (i) the SESH interest acquired by Enable and (ii) the Enable units issued to CenterPoint Energy for the SESH interest pro rata based on the time each party held the relevant interest. On July 25, 2014, the Partnership received a $7 million distribution from SESH for the three month period ended June 30, 2014, representing the Partnership's 49.90% interest in SESH. Under the terms of the agreement, the Partnership made a payment of approximately $1 million to CenterPoint Energy related to the additional 24.95% interest during the quarter ending September 30, 2014.

On June 13, 2014, SESH made a special distribution of the proceeds of its $400 million senior note issuance, less debt issuance costs, which resulted in a $198 million return of investment to the Partnership. In August 2014, the Partnership contributed $187 million to SESH which was utilized to repay SESH's $375 million senior notes due August 2014, increasing the book value of Enable's 50% investment in SESH. The Partnership and other members of SESH intend to contribute or otherwise return the remaining special distribution to SESH as necessary for general SESH purposes, including capital expenditures associated with SESH's expansion plans.

The Partnership shares operations of SESH with Spectra Energy Partners, LP under service agreements. The Partnership is responsible for the field operations of SESH. SESH reimburses each party for actual costs incurred, which are billed based upon a combination of direct charges and allocations. During the years ended December 31, 2015, 2014 and 2013, the Partnership billed SESH $12 million, $13 million and $15 million, respectively, associated with these service agreements.

The Partnership includes equity in earnings of equity method affiliates under the Other Income (Expense) caption in the Combined and Consolidated Statements of Income for the years ended December 31, 2015, 2014 and 2013.

Investment in Equity Method Affiliates:

		(In millions)
Balance as of December 31, 2012	**$**	**405**
Distributions to CenterPoint Energy		(196)
Equity in earnings of equity method affiliate		15
Capitalized interest on investment in SESH		(2)
Distributions from equity method affiliate		(24)
Balance as of December 31, 2013		**198**
Interest acquisition of SESH		161
Return of investment from SESH refinancing		(198)
Additional investment in SESH		187
Equity in earnings of equity method affiliate		20
Contributions to equity method affiliate		3
Distributions from equity method affiliate		(23)
Balance as of December 31, 2014		**348**
Interest acquisition of SESH		1
Equity in earnings of equity method affiliate		29
Contributions to equity method affiliate		8
Distributions from equity method affiliate		(42)
Balance as of December 31, 2015	**$**	**344**

Equity in Earnings of Equity Method Affiliates:

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
SESH	$ 29	$ 20	$ 15

Distributions from Equity Method Affiliates:

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
SESH [(1)]	$ 42	$ 23	$ 24

(1) Excludes $198 million in special distributions for the return of investment in SESH for the year ended December 31, 2014.

Summarized financial information of SESH is presented below:

	December 31, 2015	December 31, 2014
	(In millions)	
Balance Sheets:		
Current assets	$ 45	$ 57
Property, plant and equipment, net	1,127	1,127
Total assets	$ 1,172	$ 1,184
Current liabilities	$ 18	$ 19
Long-term debt	397	397
Members' equity	757	768
Total liabilities and members' equity	$ 1,172	$ 1,184
Reconciliation:		
Investment in SESH	$ 344	$ 348
Less: Capitalized interest on investment in SESH	(1)	(2)
The Partnership's share of members' equity	$ 343	$ 346

	Year Ended December 31, 2015	2014	2013
	(In millions)		
Income Statements:			
Revenues	$ 115	$ 108	$ 107
Operating income	71	69	66
Net income	57	48	47

(10) Debt

The following table presents the Partnership's outstanding debt as of December 31, 2015 and 2014.

	December 31, 2015	December 31, 2014
	(In millions)	
Commercial Paper	$ 236	$ 253
Revolving Credit Facility	310	—
2015 Term Loan Facility	450	—
Notes payable—affiliated companies	363	363
2019 Notes	500	500
2024 Notes	600	600
2044 Notes	550	550
EOIT Senior Notes	250	250
Premium on long-term debt	23	28
Total debt	3,282	2,544
Less amount classified as short-term debt[1]	236	253
Less Notes payable—affiliated companies (Note 14)	363	363
Total long-term debt	$ 2,683	$ 1,928

(1) Short-term debt includes $236 million and $253 million of commercial paper as of December 31, 2015 and 2014, respectively.

Maturities of outstanding debt, excluding unamortized premiums, are as follows (in millions):

2016	$ 236
2017	363
2018	450
2019	500
2020	560
Thereafter	1,150

Revolving Credit Facility

On June 18, 2015, the Partnership amended and restated its Revolving Credit Facility to, among other things, increase the borrowing capacity thereunder to $1.75 billion and extend its maturity date to June 18, 2020. As of December 31, 2015, there were $310 million of principal advances and $3 million in letters of credit outstanding under the Revolving Credit Facility. However, as discussed below, commercial paper borrowings effectively reduce our borrowing capacity under this Revolving Credit Facility. The weighted average interest rate of the Revolving Credit Facility was 1.85% as of December 31, 2015.

The Revolving Credit Facility permits outstanding borrowings to bear interest at the 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, 2015, the applicable margin for LIBOR-based borrowings under the Revolving Credit Facility was 1.50% 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, 2015, the commitment fee under the Revolving Credit Facility was 0.20% per annum based on the Partnership’s credit ratings. The commitment fee is recorded as interest expense in the Partnership's Combined and Consolidated Statements of Income.

The Revolving Credit Facility contains a financial covenant requiring us to maintain a ratio of consolidated funded debt to consolidated EBITDA as defined under the Revolving Credit Facility as of the last day of each fiscal quarter of less than or equal to 5.00 to 1.00; provided that, for any three fiscal quarters including and following any fiscal quarter in which the aggregate value of one or more acquisitions by us or certain of our subsidiaries with a purchase price of at least $25 million in the aggregate, the consolidated funded debt to consolidated EBITDA ratio as of the last day of each such fiscal quarter during such period would be permitted to be up to 5.50 to 1.00.

The Revolving Credit Facility also contains covenants that restrict us and certain subsidiaries in respect of, among other things, mergers and consolidations, sales of all or substantially all assets, incurrence of subsidiary indebtedness, incurrence of liens, transactions with affiliates, designation of subsidiaries as Excluded Subsidiaries (as defined in the Revolving Credit Facility), restricted payments, changes in the nature of their respective businesses and entering into certain restrictive agreements. Borrowings under the Revolving Credit Facility are subject to acceleration upon the occurrence of certain defaults, including, among others, payment defaults on such facility, breach of representations, warranties and covenants, acceleration of indebtedness (other than intercompany and non-recourse indebtedness) of $100 million or more in the aggregate, change of control, nonpayment of uninsured money judgments in excess of $100 million, and the occurrence of certain ERISA and bankruptcy events, subject where applicable to specified cure periods.

Commercial Paper

The Partnership has a commercial paper program pursuant to which the Partnership is authorized to issue up to $1.4 billion of commercial paper. The commercial paper program is supported by our Revolving Credit Facility, and outstanding commercial paper effectively reduces our borrowing capacity thereunder. There was $236 million and $253 million outstanding under our commercial paper program as of December 31, 2015 and 2014, respectively. Any reduction in our credit ratings could prevent us from accessing the commercial paper markets. The weighted average interest rate for the outstanding commercial paper was 1.63% as of December 31, 2015.

Term Loan Facilities

On July 31, 2015, the Partnership entered into a Term Loan Agreement dated as of July 31, 2015, providing for an unsecured three-year $450 million term loan facility (2015 Term Loan Facility). The entire $450 million principal amount of the 2015 Term Loan Facility was borrowed by Enable on July 31, 2015. The 2015 Term Loan Facility contains an option, which may be exercised up to two times, to extend the term of the 2015 Term Loan Facility, in each case, for an additional one-year term. The 2015 Term Loan Facility provides an option to prepay, without penalty or premium, the amount outstanding, or any portion thereof, in a minimum amount of $1 million, or any multiple of $0.5 million in excess thereof. As of December 31, 2015, there was $450 million outstanding under the 2015 Term Loan Facility.

The 2015 Term Loan Facility provides that outstanding borrowings bear interest at the LIBOR and/or an alternate base rate, at the Partnership's election, plus an applicable margin. The applicable margin is based on our applicable credit ratings. As of December 31, 2015, the applicable margin for LIBOR-based borrowings under the 2015 Term Loan Facility was 1.375% based on our credit ratings. As of December 31, 2015, the weighted average interest rate of the 2015 Term Loan Facility was 1.80%.

Senior Notes

On May 27, 2014, the Partnership completed the private offering of $500 million 2.400% senior notes due 2019 (2019 Notes), $600 million 3.900% senior notes due 2024 (2024 Notes) and $550 million 5.000% senior notes due 2044 (2044 Notes), with registration rights. The Partnership received aggregate proceeds of $1.63 billion. Certain of the proceeds were used to repay the $1.05 billion senior unsecured 2013 Term Loan Facility, and certain of the proceeds were used to repay the EOIT $250 million variable rate term loan and the EOIT $200 million 6.875% senior notes due July 15, 2014, and for general corporate purposes. On July 15, 2014, the Partnership repaid the EOIT $200 million 6.875% senior notes. A wholly owned subsidiary of CenterPoint Energy has guaranteed collection of the Partnership's obligations under the 2019 Notes and 2024 Notes, on an unsecured subordinated basis, subject to automatic release on May 1, 2016.

In connection with the issuance of the 2019 Notes, 2024 Notes and 2044 Notes, the Partnership, CenterPoint Energy Resources Corp., as guarantor, and RBS Securities Inc., Merrill Lynch, Pierce, Fenner & Smith Incorporated, Credit Suisse Securities (USA) LLC, and RBC Capital Markets, LLC, as representatives of the initial purchasers, entered into a registration rights agreement whereby the Partnership and the guarantor agreed to file with the SEC a registration statement relating to a registered offer to exchange the 2019 Notes, 2024 Notes and 2044 Notes for new series of the Partnership's notes in the same aggregate principal amount as, and with terms substantially identical in all respects to, the 2019 Notes, 2024 Notes and 2044 Notes. The agreement provided for the accrual of additional interest if the Partnership did not complete an exchange offer by October 9, 2015. Because an exchange offer was not consummated by October 9, 2015, additional interest began accruing on the 2019 Notes, 2024 Notes and 2044 Notes on October 10, 2015, at a rate of 0.25% per year until the first 90-day period after such date. On December 29, 2015, the Partnership completed the exchange offer. As a result, the Partnership recognized approximately $1 million of additional interest expense during 2015.

The indenture governing the 2019 Notes, 2024 Notes and 2044 Notes contains certain restrictions, including, among others, limitations on our ability and the ability of our principal subsidiaries to: (i) consolidate or merge and sell all or substantially all of our and our subsidiaries' assets and properties; (ii) create, or permit to be created or to exist, any lien upon any of our or our principal subsidiaries' principal property, or upon any shares of stock of any principal subsidiary, to secure any debt; and (iii) enter into certain sale-leaseback transactions. These covenants are subject to certain exceptions and qualifications.

As of December 31, 2015, the Partnership's debt included EOIT's $250 million 6.25% senior notes due March 2020 (the EOIT Senior Notes). The EOIT Senior Notes have $23 million unamortized premium at December 31, 2015, resulting in an effective interest rate of 5.6%, during the year ended December 31, 2015. These senior notes do not contain any financial covenants other than a limitation on liens. This limitation on liens is subject to certain exceptions and qualifications.

Financing Costs

Unamortized debt expense of $18 million and $17 million at December 31, 2015 and 2014, respectively, is classified in Other Assets in the Consolidated Balance Sheets and is being amortized over the life of the respective debt. Unamortized premium on long-term debt of $23 million and $28 million at December 31, 2015 and 2014, respectively, is classified as either Long-Term Debt or Short-Term Debt, consistent with the underlying debt instrument, in the Consolidated Balance Sheets and is being amortized over the life of the respective debt.

The Partnership recorded a $4 million loss on extinguishment of debt in the year ended December 31, 2014 associated with the retirement of the $1.05 billion 2013 Term Loan Facility and the EOIT $250 million variable rate term loan, which is included in Other, net on the Combined and Consolidated Statements of Income.

As of December 31, 2015, the Partnership and EOIT were in compliance with all of their debt agreements, including financial covenants.

(11) Fair Value Measurements

Certain assets and liabilities are recorded at fair value in the 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 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 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 period ended December 31, 2015, there were transfers between 2 and Level 3 investments, as shown in the reconciliation below.

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, commercial paper and other such financial instruments on the 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, 2015 and 2014:

	December 31, 2015		December 31, 2014	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Long-Term Debt				
Long-term notes payable—affiliated companies (Level 2)	$ 363	$ 350	$ 363	$ 362
Revolving Credit Facility (Level 2)(1)	310	310	—	—
2015 Term Loan Facility (Level 2)	450	450	—	—
EOIT Senior Notes (Level 2)	273	280	279	282
Enable Midstream Partners, LP, 2019, 2024 and 2044 Notes (Level 2)	1,650	1,255	1,649	1,592

(1) Borrowing capacity is reduced by our borrowings outstanding under the commercial paper program. $236 million and $253 million of commercial paper was outstanding as of December 31, 2015 and 2014, respectively.

The fair value of the Partnership's Long-term notes payable—affiliated companies, Revolving Credit Facility, and 2015 Term Loan Facility, along with the EOIT Senior Notes and Enable Midstream Partners, LP, 2019, 2024 and 2044 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 years ended December 31, 2015, 2014 and 2013, the Partnership remeasured the Service Star assets at fair value. At December 31, 2015 and 2014, management reassessed the carrying value of the Service Star business line, a component of the Gathering and Processing segment which provides measurement and communication services to third parties, based upon higher than expected losses of customers during 2015 and 2014 due to decreases of crude oil and natural gas prices. 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. 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 years ended December 31, 2015, 2014 and 2013, the Partnership recognized a $10 million, $7 million and $12 million impairment, respectively. The $10 million consisted of a $9 million write-down of property, plan and equipment and a $1 million write-down of materials and supplies inventory considered either excess or obsolete. The $7 million impairment consisted of write-downs of property plant, and equipment. The $12 million impairment consisted 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, 2015, due to decreases of crude oil and natural gas prices during 2015, management reassessed the carrying value of the Partnership's investment in the Atoka assets, a component of the Gathering and Processing segment. Based on forecasted future undiscounted cash flows, management determined that the carrying value of the Atoka 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 intangible assets, the Partnership recognized a $25 million impairment during the year ended December 31, 2015. The $25 million impairment consisted of a $19 million write-down of property plant, and equipment and a $6 million write-down of intangible assets.

Additionally, during the year ended December 31, 2015, the Partnership recorded a $12 million impairment on jurisdictional pipelines in our transportation and storage segment.

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 Partnership has presented the fair values of its derivative contracts under master netting agreements using a net fair value presentation.

The following tables summarize the Partnership's assets and liabilities that are measured at fair value on a recurring basis as of December 31, 2015 and 2014:

December 31, 2015	Commodity Contracts		Gas Imbalances [(1)]	
	Assets	Liabilities	Assets [(2)]	Liabilities [(3)]
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$ 17	$ 3	$ —	$ —
Significant other observable inputs (Level 2)	10	—	17	$ 20
Unobservable inputs (Level 3)	4	—	—	$ —
Total fair value	31	3	17	$ 20
Netting adjustments	(3)	(3)	—	$ —
Total	$ 28	$ —	$ 17	$ 20

December 31, 2014	Commodity Contracts		Gas Imbalances [(1)]	
	Assets	Liabilities	Assets [(2)]	Liabilities [(3)]
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$ 33	$ 4	$ —	$ —
Significant other observable inputs (Level 2)	2	—	40	12
Unobservable inputs (Level 3)	5	—	—	—
Total fair value	40	4	40	12
Netting adjustments	(4)	(4)	—	—
Total	$ 36	$ —	$ 40	$ 12

(1) 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 EOIT 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, 2015 and 2014.

(2) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of $6 million and $4 million at December 31, 2015 and 2014, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

(3) Gas imbalance liabilities exclude fuel reserves for over retained fuel due to shippers of $5 million and $1 million at December 31, 2015 and 2014, respectively, which fuel reserves are based on the value of natural gas at the time the imbalance was created and which are not subject to revaluation at fair market value.

Changes in Level 3 Fair Value Measurements

The following tables provides a reconciliation of changes in the fair value of our Level 3 financial assets between the periods presented.

	Commodity Contracts	
	Crude oil (for condensate) financial futures/swaps	Natural gas liquids financial futures/swaps
	(In millions)	
Balance as of December 31, 2014	$ 5	$ —
Gains included in earnings	12	10
Settlements	(8)	(6)
Transfers out of Level 3[1]	(9)	—
Balance as of December 31, 2015	$ —	$ 4

(1) The Partnership utilizes WTI crude swaps to manage exposure to condensate price risk. As the over-the-counter WTI crude swap is an active market, these derivative instruments will be classified as Level 2 as of December 31, 2015.

Quantitative Information on Level 3 Fair Value Measurements

The Partnership utilizes the market approach to measure the fair value of our commodity contracts. The significant unobservable inputs used in this approach to fair value are longer dated price quotes. Our sensitivity to these longer dated forward curve prices are presented in the table below. Significant changes in any of those inputs in isolation would result in significantly different fair value measurements, depending on our short or long position in contracts.

	December 31, 2015	
Product Group	Fair Value	Forward Curve Range
	(In millions)	(Per gallon)
Natural gas liquids	$ 4	$0.339 - $0.436

(12) Derivative Instruments and Hedging Activities

The Partnership is exposed to certain risks relating to its ongoing business operations. The primary risk managed using derivative instruments is commodity price 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, NGL futures and swaps, and WTI crude futures and swaps for condensate sales are used to manage the Partnership’s NGL and condensate exposure associated with its processing agreements;
- natural gas futures and 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 Other Assets or Liabilities in the Consolidated Balance Sheets and earnings are recognized and recorded in the period in which physical delivery of the commodity occurs. Management applies normal purchases and normal sales treatment to: (i) commodity contracts for the purchase and sale of natural gas used in or produced by the Partnership's operations and (ii) commodity contracts for the purchase and sale of NGLs produced by the Partnership's gathering and processing business.

The Partnership recognizes its non-exchange traded derivative instruments as Other Assets or Liabilities in the Consolidated Balance Sheets at fair value with such amounts classified as current or long-term based on their anticipated settlement. Exchange traded transactions are settled on a net basis daily through margin accounts with a clearing broker and, therefore, are recorded at fair value on a net basis in Other Current Assets in the Consolidated Balance Sheets.

As of December 31, 2015 and 2014, the Partnership had no derivative instruments that were designated as cash flow or fair value hedges for accounting purposes.

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 seek or be forced to enter into alternative arrangements. In that event, the Partnership's financial results could be adversely affected, and the Partnership could incur losses.

Derivatives Not Designated As Hedging Instruments

Derivative instruments not designated as hedging instruments for accounting purposes 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.

Quantitative Disclosures Related to Derivative Instruments

The majority of natural gas physical purchases and sales not designated as hedges for accounting purposes are priced based on a monthly or daily index, and the fair value is subject to little or no market price risk. Natural gas physical sales volumes exceed natural gas physical purchase volumes due to the marketing of natural gas volumes purchased via the Partnership's processing contracts, which are not derivative instruments.

As of December 31, 2015 and 2014, the Partnership had the following derivative instruments that were not designated as hedging instruments for accounting purposes:

	December 31, 2015		December 31, 2014	
	Gross Notional Volume			
	Purchases	Sales	Purchases	Sales
Natural gas— TBtu(1)				
Physical purchases/sales	2	51	4	32
Financial fixed futures/swaps	1	37	5	35
Financial basis futures/swaps	4	38	7	54
Crude oil (for condensate)— MBbl(2)				
Financial futures/swaps	—	506	—	274
Natural gas liquids— MBbl(3)				
Financial futures/swaps	75	1,011	—	—

(1) As of December 31, 2015, 97.7% of the natural gas contracts have durations of one year or less and 2.3% have durations of more than one year and less than two years. As of December 31, 2014, 91.2% of the natural gas contracts had durations of one year or less, 6.5% had durations of more than one year and less than two years and 2.2% have durations of more than two years.
(2) As each of December 31, 2015 and 2014, 100% of the crude oil (for condensate) contracts have durations of one year or less.
(3) As of December 31, 2015, 100% of the natural gas liquid contracts have durations of one year or less.

Balance Sheet Presentation Related to Derivative Instruments

The fair value of the derivative instruments that are presented in the Partnership's Consolidated Balance Sheet at December 31, 2015 and 2014 that were not designated as hedging instruments for accounting purposes are as follows:

		December 31, 2015		December 31, 2014	
		Fair Value			
Instrument	Balance Sheet Location	Assets	Liabilities	Assets	Liabilities
		(In millions)			
Natural gas					
Financial futures/swaps	Other Current	$ 17	$ 3	$ 34	$ 4
Physical purchases/sales	Other Current	1	—	1	—
Crude oil (for condensate)					
Financial futures/swaps	Other Current	9	—	5	—
Natural gas liquids					
Financial futures/swaps	Other Current	4	—	—	—
Total gross derivatives (1)		$ 31	$ 3	$ 40	$ 4

(1) See Note 11 for a reconciliation of the Partnership's total derivatives fair value to the Partnership's Consolidated Balance Sheet as of December 31, 2015 and 2014.

Income Statement Presentation Related to Derivative Instruments

The following table presents the effect of derivative instruments on the Partnership's Consolidated Statements of Income for the years ended December 31, 2015, 2014 and 2013:

	Amounts Recognized in Income		
	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Natural gas financial futures/swaps gains (losses)	$ 26	$ 37	$ (1)
Natural gas physical purchases/sales gains (losses)	(9)	1	—
Crude oil (for condensate) financial futures/swaps gains (losses)	12	9	—
Natural gas liquids financial futures/swaps gains (losses)	10	2	—
Total	$ 39	$ 49	$ (1)

For derivatives not designated as hedges in the tables above, amounts recognized in income for the years ended December 31, 2015, 2014 and 2013, if any, are reported in Product Sales.

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 senior unsecured debt rating to a below investment grade rating, at December 31, 2015, the Partnership 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, 2015. In addition, the Partnership could be required to provide additional credit assurances in future dealings with third parties, which could include letters of credit or cash collateral.

(13) Supplemental Disclosure of Cash Flow Information

The following table provides information regarding supplemental cash flow information:

	Year Ended December 31, 2015	2014	2013
	(In millions)		
Supplemental Disclosure of Cash Flow Information:			
Cash Payments:			
Interest, net of capitalized interest	$ 85	$ 77	$ 65
Income taxes (refunds), net	1	1	(9)
Non-cash transactions:			
Accounts payable related to capital expenditures	52	93	43
Issuance of common units upon interest acquisition of SESH (Note 9)	1	161	—
Acquisition of Enogex	—	—	3,788

(14) Related Party Transactions

The material related party transactions with CenterPoint Energy, OGE Energy and their respective subsidiaries are summarized below. There were no material related party transactions with other affiliates.

Revenues

The Partnership's revenues from affiliated companies accounted for 7%, 6%, and 9% of revenues during the years ended December 31, 2015, 2014 and 2013, respectively. Amounts of revenues from affiliated companies included in the Partnership's Combined and Consolidated Statements of Income are summarized as follows:

	Year Ended December 31, 2015	2014	2013
	(In millions)		
Gas transportation and storage service revenue — CenterPoint Energy	$ 110	$ 112	$ 108
Natural gas product sales — CenterPoint Energy	7	22	70
Gas transportation and storage service revenue — OGE Energy (1)	37	39	32
Natural gas product sales — OGE Energy (1)	8	13	14
Total revenues — affiliated companies	$ 162	$ 186	$ 224

(1) The Partnership's contracts with OGE Energy to transport and sell natural gas to OGE Energy's natural gas-fired generation facilities and store natural gas are reflected in Partnership's Combined and Consolidated Statements of Income beginning on May 1, 2013. On March 17, 2014, the Partnership and the electric utility subsidiary of OGE Energy signed a new transportation agreement effective May 1, 2014 with a primary term through April 30, 2019. Following the primary term, the agreement will remain in effect from year to year thereafter unless either party provides notice of termination to the other party at least 180 days prior to the commencement of the succeeding annual period.

Cost of natural gas purchases

Amounts of natural gas purchased from affiliated companies included in the Partnership's Combined and Consolidated Statements of Income are summarized as follows:

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Cost of natural gas purchases — CenterPoint Energy	$ 2	$ 2	$ 4
Cost of natural gas purchases — OGE Energy	15	19	8
Total cost of natural gas purchases — affiliated companies	$ 17	$ 21	$ 12

Corporate services and seconded employee expense

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 of CenterPoint Energy and OGE Energy for all employee costs under the seconding agreements until the seconded employees transition from CenterPoint Energy and OGE Energy to the Partnership. The Partnership transitioned seconded employees from CenterPoint Energy and OGE Energy to the Partnership effective January 1, 2015, except for certain employees who are participants under OGE Energy's defined benefit and retiree medical plans, who will remain seconded to the Partnership, subject to certain termination rights of the Partnership and OGE Energy. The Partnership's reimbursement of OGE Energy for seconded employee costs arising out of OGE Energy's defined benefit and retiree medical plans is fixed at $6 million in each of 2015 and 2016, $5 million in 2017, and at actual cost subject to a cap of $5 million in 2018 and thereafter, in the event of continued secondment.

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 each of 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 Enable GP. The Partnership reimburses CenterPoint Energy and OGE Energy for these services up to annual caps, which for 2015 are $15 million and $11 million, respectively.

Amounts charged to the Partnership by affiliates for seconded employees and corporate services, included primarily in Operation and maintenance expenses and General and administrative expenses in the Partnership's Combined and Consolidated Statements of Income are as follows:

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Seconded Employee Costs - CenterPoint Energy (1)	$ —	$ 138	$ 92
Corporate Services - CenterPoint Energy	15	29	38
Seconded Employee Costs - OGE Energy (2)	35	105	78
Corporate Services - OGE Energy (2)	11	17	18
Total corporate services and seconded employees expense	$ 61	$ 289	$ 226

(1) Beginning on May 1, 2013, CenterPoint Energy assumed all employees of the Partnership and seconded such employees to the Partnership. Therefore, costs historically incurred directly by the 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 Combined and Consolidated Statements of Income beginning on May 1, 2013.

Notes payable

The Partnership has outstanding long-term notes payable—affiliated companies to CenterPoint Energy at both December 31, 2015 and 2014 of $363 million which 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%.

The Partnership recorded affiliated interest expense to CenterPoint Energy on note payable—affiliated companies of $8 million, $8 million and $34 million, respectively during the years ended December 31, 2015, 2014 and 2013, respectively.

Notes receivable

The Partnership recorded no interest income—affiliated companies from CenterPoint Energy on notes receivable—affiliated companies during the years ended December 31, 2015 and 2014 and $9 million, during the year ended December 31, 2013.

Other

In 2015, EGT relocated a portion of its pipeline in Arkansas to improve reliability and increase capacity by constructing an approximately 28.5 mile new pipeline segment and abandoning approximately 34.2 miles of existing pipelines segments. In connection with the project, EGT sold an approximately 12.4 mile pipeline segment to CenterPoint Energy's Arkansas LDC for its remaining book value of $1 million, and EGT will reimburse CenterPoint Energy's Arkansas LDC approximately $7 million dollars for cost incurred in connecting the LDC to EGT's new pipeline segment.

(15) Commitments and Contingencies

Long-Term Agreements

Long-term Agreement with XTO. In March 2013 and February 2014, Enable Bakken entered into long-term agreements with XTO to provide gathering services for certain of XTO's crude oil production through a new crude oil gathering and transportation pipeline system in North Dakota's liquids-rich Bakken Shale. Under the terms of the agreement, which includes volume commitments features or gross acreage dedication, Enable Bakken provides services to XTO over a gathering system constructed by Enable Bakken in Dunn and McKenzie Counties in North Dakota, which commenced operations in the fourth quarter of 2013, and a second gathering system constructed in Williams and Mountrail Counties in North Dakota, which commenced operations in the second quarter of 2015, with a combined capacity of up to 49,500 barrels per day. The remaining portion of the pipeline is expected to be placed in service during 2016 and 2017. As of December 31, 2015, the Partnership estimates the remaining construction costs to be $37 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,						
	2016	2017	2018	2019	2020	After 2020	Total
	(In millions)						
Noncancellable operating leases	$ 14	$ 5	$ 3	$ 1	$ —	$ —	$ 23

Total rental expense for all operating leases was $32 million, $23 million and $12 million during the years ended December 31, 2015, 2014 and 2013, respectively.

The Partnership currently occupies 162,053 square feet of office space at its executive offices under a lease that expires June 30, 2019. The lease payments are $19 million over the lease term, which began April 1, 2012. This lease has rent escalations which increase after 5 years, and will further escalate after 10 years if the lease is renewed. These lease expenses are included in General and administrative expense in the Statements of Combined and Consolidated Income.

The Partnership currently has 94 compression service agreements, of which 49 agreements are on a month-to-month basis, 22 agreements will expire in 2016, 19 agreements will expire in 2017 and 4 agreements will expire in 2018. The Partnership also has 5 gas treating lease agreements, all of which are on a month-to-month basis. These lease expenses are reflected in Operation and maintenance expense in the Statements of Combined and Consolidated Income.

Other Purchase Obligations and Commitments. In 2006, EOIT entered into a firm capacity agreement with Midcontinent Express Pipeline (MEP), which was effective beginning in 2009 for a primary term of 10 years (subject to possible extension) that gives MEP and its shippers' access to capacity on EOIT's system. The quantity of capacity subject to the MEP capacity agreement is currently 275 MMcf/d, with the quantity subject to being increased by mutual agreement pursuant to the capacity agreement.

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

	Year Ended December 31,					
	2016	2017	2018	2019	2020	Total
	(In millions)					
Other purchase obligations and commitments	$ 1	$ —	$ —	$ —	$ —	$ 1

Legal, Regulatory and Other Matters

The Partnership is involved in 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.

(16) 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 generally no longer subject to income tax (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiary, Enable Midstream Services) and are taxable at the individual partner level. The Partnership and its subsidiaries are pass-through entities for federal income tax purposes. 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 combined and consolidated financial statements. 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 and taxes associated with the Partnership's corporate subsidiary, Enable Midstream Services).

The items comprising income tax expense are as follows:

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Provision for current income taxes			
Federal	$ —	$ —	$ 1
State	1	1	1
Total provision for current income taxes	1	1	2
Provision (benefit) for deferred income taxes, net			
Federal	$ —	—	$ (1,039)
State	(1)	1	(155)
Total provision (benefit) for deferred income taxes, net	(1)	1	(1,194)
Total income tax expense (benefit)	$ —	$ 2	$ (1,192)

The following schedule reconciles the statutory Federal income tax rate to the effective income tax rate:

	Year Ended December 31,		
	2015	2014	2013
	(In millions)		
Income before income taxes	$ (771)	$ 535	$ 426
Federal statutory rate	—%	—%	35 %
Expected federal income tax expense	—	—	149
Increase in tax expense resulting from:			
State income taxes, net of federal income tax	—	2	8
Income not subject to tax	—	—	(103)
Conversion to partnership	—	—	(1,240)
Other, net	—	—	(6)
Total	—	2	(1,341)
Total income tax expense (benefit)	$ —	$ 2	$ (1,192)
Effective tax rate	—%	0.4%	(275.9)%

As a result of the conversion to a limited 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 or liability balances at December 31, 2015 and 2014 related to the Partnership.

Enable Midstream Services is subject to U.S. federal and state income taxes. Deferred income tax assets and liabilities for the operations of this corporation are recognized for temporary differences between the assets and liabilities for financial reporting and tax purposes. Changes in tax legislation are included in the relevant computations in the period in which such changes are effective.

The components of Deferred Income Taxes as of December 31, 2015 and 2014 were as follows:

	December 31,	
	2015	2014
	(In millions)	
Deferred tax assets:	$ —	$ —
Deferred tax liabilities:		
Non-current:		
Depreciation	9	9
Other	(1)	—
Total non-current deferred tax liabilities	8	9
Accumulated deferred income taxes, net	$ 8	$ 9

Uncertain Income Tax Positions

The Partnership recognizes interest and penalties as a component of income tax expense. There were no unrecognized tax benefits as of December 31, 2015, 2014 and 2013.

Tax Audits and Settlements

CenterPoint Energy’s consolidated federal income tax returns have been audited by the IRS and settled through the 2013 tax year. The federal income tax return of the Partnership has been audited through the 2013 tax year.

(17) Equity Based Compensation

Enable GP has adopted the Enable Midstream Partners, LP Long Term Incentive Plan for officers, directors and employees of the Partnership, Enable GP or affiliates, including any individual who provides services to the Partnership or Enable GP as a seconded employee, and any consultants or affiliates of Enable GP or other individuals who perform services for the Partnership.

The long term incentive plan consists of the following components: phantom units, performance units, appreciations rights, restricted units, option rights, cash incentive awards, distribution equivalent rights or other unit-based awards and unit awards. The purpose of awards under the long term incentive plan is to provide additional incentive compensation to employees providing services to the Partnership, and to align the economic interests of such employees with the interests of unitholders. The long term incentive plan will limit the number of units that may be delivered pursuant to vested awards to 13,100,000 common units, subject to proportionate adjustment in the event of unit splits and similar events. Common units cancelled, forfeited, expired or cash settled will be available for delivery pursuant to other awards. The plan is administered by the Board of Directors or a designated committee thereof.

The following table summarizes the Partnership’s compensation expense for the years ended December 31, 2015, 2014, and 2013 related to performance units, restricted units, and phantom units for the Partnership's employees and independent directors:

	Year Ended December 31,		
	2015	2014	2013
		(In millions)	
Performance units	$ 3	$ 3	$ —
Restricted units	7	10	—
Phantom units	1	2	—
Total compensation expense	$ 11	$ 15	$ —

Performance Units

The Board of Directors has authorized various grants of performance based phantom units (performance units) under the Long Term Incentive Plan pursuant to the 2014 Long Term Incentive Plan Annual Award Program, to certain employees providing services to the Partnership, including executive officers, that cliff vest three years from the grant date. The performance units provide for accelerated vesting if there is a change in control (as defined in the Enable Midstream Partners, LP Long Term Incentive Plan). Each performance unit is subject to forfeiture if the recipient terminates employment with the Partnership prior to the end of the three-year award cycle for any reason other than death, disability or retirement. In the event of death or disability, a participant will receive a payment based on the targeted achievement of the performance goals during the award cycle. In the event of retirement, a participant will receive a pro rated payment based on the target performance, rather than actual performance, of the performance goals during the award cycle.

The payment of performance units is dependent upon the Partnership's total unitholder return ranking relative to a peer group of companies over the period of January 1, 2015 through December 31, 2017 as compared to a target set at the time of the grant by the Board of Directors. Any performance units that cliff vest three years from the grant date (i.e. the three year award cycle) will be payable in the Partnership's common units. All of these performance units are classified as equity in the Partnership's 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 canceled. Payout requires approval of the Board of Directors.

The fair value of the performance units was estimated on the grant date using a lattice-based valuation model that factors in information, including the expected distribution 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. Distributions are accumulated and paid at vesting, and therefore, are not included in the fair value calculation. Due to the short trading history of the Partnership's common units, expected price volatility is based on one year of daily stock price observations, combined with the average of the two-year volatility of the peer group companies used to determine the total unitholder return ranking. 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 Partnership’s performance units. The number of performance units granted based on total unitholder return and the assumptions used to calculate the grant date fair value of the performance units based on total unitholder return are shown in the following table.

	2015	2014
Number of units granted	501,474	563,963
Fair value of units granted	$ 16.59	$ 26.12
Expected price volatility	27.6%	22.2%
Risk-free interest rate	0.99%	0.83%
Expected life of units (in years)	3.00	3.00

Restricted Units

The Board of Directors has authorized various grants of time-based restricted units (restricted units) to certain employees providing services to the Partnership that are subject to cliff vesting over various terms, not longer than four years from the grant date. Prior to vesting, each share of restricted stock is subject to forfeiture if the recipient ceases to render substantial services to the Partnership for any reason other than death, disability or retirement. During the restriction period these units may not be sold, assigned, transferred or pledged and are subject to a risk of forfeiture.

On April 16, 2014, 375,000 restricted units were granted to the Chief Executive Officer of Enable GP, of which 40% vested on August 1, 2014, 20% vested on February 1, 2015 and 40% vested on July 15, 2015. Additionally, on April 16, 2014, the Board of Directors granted 150,000 restricted units to the Chief Executive Officer of Enable GP, which 50% vested on May 29, 2015 and 50% was forfeited upon his departure. On April 16, 2014, 137,500 restricted units were granted to the Chief Financial Officer of Enable GP, which vested 45.46% on March 1, 2015 and will vest 54.54% on March 1, 2016. Additionally, on April 16, 2014, 25,000 restricted units were granted to the Chief Financial Officer of Enable GP, which vest four years from the grant date. Prior to vesting, each share of restricted stock is subject to forfeiture if the recipient ceases to render substantial services to the Partnership for any reason other than death, disability or retirement. During the restriction period these units may not be sold, assigned, transferred or pledged and are subject to a risk of forfeiture.

The fair value of the restricted units was based on the closing market price of the Partnership's common unit on the grant date. Compensation expense for the restricted units is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over a vesting period, as defined in the agreements. Distributions are paid as declared prior to vesting and, therefore, are included in the fair value calculation. After payment, distributions are not subject to forfeiture. The expected life of the restricted units is based on the non-vested period since inception of the award cycle. There are no post-vesting restrictions related to the Partnership's restricted units.

The number of restricted units granted related to the Partnership's employees and the grant date fair value are shown in the following table.

	2015	2014
Restricted units granted on April 16, 2014 to the Chief Executive Officer and Chief Financial Officer of Enable GP	—	687,500
Fair value of restricted units granted	$ —	$ 22.60
Restricted units granted to the Partnership's employees	279,677	304,901
Fair value of restricted units granted	$16.75 - $19.18	$23.56 - $25.50

Phantom Units

On April 21, 2014, 100,000 time-based phantom units (phantom units) were granted to certain employees providing services to the Partnership, including executive officers, that vested on the first anniversary of the date of grant. Prior to vesting, each share of restricted units was subject to forfeiture if the recipient ceased to render substantial services to the Partnership for any reason other than death, disability or retirement. During the restriction period these units may not be sold, assigned, transferred or pledged and were subject to a risk of forfeiture.

During 2014, the Board of Directors granted 6,718 phantom units to the independent directors of Enable GP, for their service as directors, which vested one year from the grant date.

The fair value of the phantom units was based on the closing market price of the Partnership's common unit on the grant date. Compensation expense for the phantom unit is a fixed amount determined at the grant date fair value and is recognized as services are rendered by employees over a one-year vesting period. Distributions are accumulated and paid at vesting and, therefore, are not included in the fair value calculation. The expected life of the phantom unit is based on the non-vested period since inception of the one-year award cycle. There are no post-vesting restrictions related to the Partnership's phantom unit. The number of phantom units granted and the grant date fair value are shown in the following table.

	2015	2014
Phantom units granted	9,817	106,718
Fair value of phantom units granted	$ 12.70	$23.16 - $23.70

Other Awards

During 2015, the Board of Directors granted 17,384 common units to the independent directors of Enable GP, for their service as directors, which vested immediately. The fair value of the common units was based on the closing market price of the Partnership's common unit on the grant date.

	2015
Common units granted	17,384
Fair value of common units granted	$ 11.12

Units Outstanding

A summary of the activity for the Partnership's performance units, restricted units, and phantom units as of December 31, 2015 and changes in 2015 are shown in the following table.

	Performance Units		Restricted Stock		Phantom Units		Other Awards	
	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit	Number of Units	Weighted Average Grant-Date Fair Value, Per Unit
	(In millions, except unit data)							
Units Outstanding at 12/31/2014	552,581	$ 26.12	838,068	$ 23.47	98,718	$ 23.20	—	$ —
Granted[1]	501,474	16.59	279,677	17.14	9,817	12.70	17,384	11.12
Vested	(1,254)	26.12	(400,801)	22.72	(96,718)	23.20	(17,384)	11.12
Forfeited	(238,291)	24.70	(135,172)	23.06	(2,000)	23.16	—	—
Units Outstanding at 12/31/2015	814,510	20.67	581,772	21.04	9,817	12.70	—	—
Aggregate Intrinsic Value of Units Outstanding at 12/31/2015	$ 6		$ 5		$ —		$ —	

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

A summary of the Partnership's performance, restricted, and phantom units' aggregate intrinsic value (market value at vesting date) and fair value of units vested (market value at date of grant) during the year ended December 31, 2015 are shown in the following table.

	December 31, 2015		
	Performance Units	Restricted Stock	Phantom Units
	(In millions)		
Aggregate Intrinsic Value of Units Vested	$ —	$ 10	$ 2
Fair Value of Units Vested	—	13	2

Unrecognized Compensation Cost

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

	December 31, 2015	
	Unrecognized Compensation Cost (In millions)	Weighted Average to be Recognized (In years)
Performance Units	$ 11	2.07
Restricted Units	8	1.74
Phantom Units	—	0.35
Total	$ 19	

As of December 31, 2015, there were 11,054,681 units available for issuance under the long term incentive plan.

(18) Reportable Segments

The Partnership's determination of reportable 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 reportable segments are the same as those described in the summary of significant accounting policies described in Note 1, which explain that some executive benefit costs of the Partnership prior to May 1, 2013 have not been allocated to reportable segments. The Partnership uses operating income as the measure of profit or loss for its reportable segments.

The Partnership's assets and operations are organized into two reportable segments: (i) Gathering and Processing, which primarily provides natural gas gathering, processing and fractionation services and crude oil gathering for our producer customers, and (ii) Transportation and Storage, which provides interstate and intrastate natural gas pipeline transportation and storage service primarily 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.

Financial data for reportable segments are as follows:

Year Ended December 31, 2015	Gathering and Processing	Transportation and Storage [1]	Eliminations	Total
		(In millions)		
Revenues [2]	$ 1,663	$ 1,132	$ (377)	$ 2,418
Cost of natural gas and natural gas liquids	908	565	(376)	1,097
Operation and maintenance, General and administrative	293	230	(1)	522
Depreciation and amortization	195	123	—	318
Impairments	543	591	—	1,134
Taxes other than income tax	30	29	—	59
Operating (loss) income	$ (306)	$ (406)	$ —	$ (712)
Total assets	$ 7,548	$ 4,976	$ (1,286)	$ 11,238
Capital expenditures	$ 839	$ 110	$ —	$ 949

Year Ended December 31, 2014	Gathering and Processing	Transportation and Storage [1]	Eliminations	Total
	(In millions)			
Revenues [2]	$ 2,424	$ 1,577	$ (634)	$ 3,367
Cost of natural gas and natural gas liquids	1,585	961	(632)	1,914
Operation and maintenance, General and administrative	297	232	(2)	527
Depreciation and amortization	160	116	—	276
Impairments	8	—	—	8
Taxes other than income tax	25	31	—	56
Operating income	$ 349	$ 237	$ —	$ 586
Total assets	$ 8,356	$ 5,493	$ (2,012)	$ 11,837
Capital expenditures	$ 740	$ 103	$ (6)	$ 837

Year Ended December 31, 2013	Gathering and Processing	Transportation and Storage [1]	Eliminations	Total
	(In millions)			
Revenues [2]	$ 1,740	$ 1,149	$ (400)	$ 2,489
Cost of natural gas and natural gas liquids	1,075	636	(398)	1,313
Operation and maintenance, General and administrative	222	209	(2)	429
Depreciation and amortization	117	95	—	212
Impairments	12	—	—	12
Taxes other than income tax	20	34	—	54
Operating income	$ 294	$ 175	$ —	$ 469
Total assets	$ 7,157	$ 5,717	$ (1,642)	$ 11,232
Capital expenditures	$ 431	$ 142	$ —	$ 573

(1) See Note 9 for discussion regarding ownership interest in SESH and related equity earnings included in the Transportation and Storage segment for the years ended December 31, 2015, 2014 and 2013.

(2) The Partnership had no external customers accounting for 10% or more of revenues in periods shown. See Note 14 for revenues from affiliated companies.

(19) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data for 2015 and 2014 are as follows:

	Quarters Ended			
	March 31, 2015	June 30, 2015	September 30, 2015	December 31, 2015
	(in millions, except per unit data)			
Revenues	$ 616	$ 590	$ 646	$ 566
Cost of natural gas and natural gas liquids	292	277	287	241
Operating income (loss) (1)	104	93	(975)	66
Net income (loss)	91	77	(991)	52
Net income (loss) attributable to Enable Midstream Partners, LP	91	77	(985)	65
Basic and diluted earnings (loss) per common limited partner unit	$ 0.22	$ 0.18	$ (2.33)	$ 0.15
Basic and diluted earnings (loss) per subordinated limited partner unit	$ 0.21	$ 0.18	$ (2.34)	$ 0.15

	Quarters Ended			
	March 31, 2014	June 30, 2014	September 30, 2014	December 31, 2014
	(in millions, except per unit data)			
Revenues	$ 1,002	$ 827	$ 803	$ 735
Cost of natural gas and natural gas liquids	633	478	439	364
Operating income	162	138	152	134
Net income	150	121	139	123
Net income attributable to Enable Midstream Partners, LP	149	120	139	122
Basic and diluted earnings per common limited partner unit	$ 0.38	$ 0.29	$ 0.33	$ 0.29
Basic and diluted earnings per subordinated limited partner unit	$ —	$ 0.29	$ 0.33	$ 0.29

(1) In the third quarter of 2015, the Partnership recorded a $1,087 million impairment to goodwill. For more information see Note 8.

(20) Subsequent Events

Preferred Units

On January 28, 2016, the Partnership entered into a Purchase Agreement (the Purchase Agreement) with CenterPoint Energy to issue and sell in a Private Placement an aggregate of 14,520,000 10% Series A Fixed-to-Floating Non-Cumulative Redeemable Perpetual Preferred Units (Preferred Units) for a cash purchase price of $25.00 per Preferred Unit, resulting in total gross proceeds of $363 million. The closing of the Private Placement, which is expected to occur prior to the end of the first quarter of 2016, is subject to the completion of due diligence by the CenterPoint Energy, including the review of the Partnership’s audited financial statements and this Form 10-K, and certain customary closing conditions. In connection with the Private Placement, the Partnership intends to redeem the $363 million of Notes payable—affiliated companies scheduled to mature in 2017 payable to a subsidiary of CenterPoint Energy.

Pursuant to the Purchase Agreement, in connection with the closing of the Private Placement, the General Partner will execute a Third Amended and Restated Agreement of Limited Partnership of the Partnership (the Amended Partnership Agreement) to, among other things, authorize and establish the terms of the Preferred Units and the other series of preferred units that are issuable upon conversion of the Preferred Units, in the form attached as an exhibit to the Purchase Agreement. Also, the Partnership has agreed to enter into a Registration Rights Agreement with CenterPoint Energy at the closing of the Private Placement, pursuant to which, among other things, the Partnership will give CenterPoint Energy certain rights to require the Partnership to file and maintain a registration statement with respect to the resale of the Preferred Units and any other series of preferred units or common units representing limited partnership interests in the Partnership that are issuable upon conversion of the Preferred Units.

Debt

On February 2, 2016, Standard & Poor's Ratings Services lowered its credit rating on the Partnership from an investment grade rating to a noninvestment grade rating. The short-term rating on the Partnership was also reduced from an investment grade rating to a noninvestment grade rating. As a result, we expect our access to our commercial paper program to be limited until these ratings improve. As of February 15, 2016, the Partnership repaid $214 million of commercial paper outstanding at December 31, 2015, and subsequently borrowed $355 million under the Revolving Credit Facility.

OGE Energy Corp.

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405-553-3000
www.oge.com

February 26, 2016

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, 2015, 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