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, 2018

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 every Interactive Data File required to be submitted 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 such files). ☑ Yes o No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company" and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☑	Accelerated filer o
Non-accelerated filer o	Smaller reporting company o
	Emerging growth company o

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. 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 29, 2018, 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 $7,032,567,628 based on the number of shares held by non-affiliates (199,732,111) and the reported closing market price of the common stock on the New York Stock Exchange on such date of $35.21.

At January 31, 2019, there were 199,732,315 shares of common stock, par value $0.01 per share, outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The Proxy Statement for the Company's 2019 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, 2018

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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
2017 Tax Act	Tax Cuts and Jobs Act of 2017
401(k) Plan	Qualified defined contribution retirement plan
AES	AES-Shady Point, Inc.
APSC	Arkansas Public Service Commission
ArcLight group	Bronco Midstream Holdings, LLC and Bronco Midstream Holdings II, LLC, collectively
ASC	FASB Accounting Standards Codification
ASU	FASB Accounting Standards Update
Bcf	Billion cubic feet
Btu	British thermal unit
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
CSAPR	Cross-State Air Pollution Rule
Dry Scrubber	Dry flue gas desulfurization unit with spray dryer absorber
ECP	Environmental Compliance Plan
EGT	Enable Gas Transmission, LLC, a wholly-owned subsidiary of Enable that operates a 5,900-mile interstate pipeline that provides natural gas transportation and storage services to customers principally in the Anadarko, Arkoma and Ark-La-Tex Basins in Oklahoma, Texas, Arkansas, Louisiana, Missouri and Kansas
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)
EOIT	Enable Oklahoma Intrastate Transmission, LLC, formerly Enogex LLC, a wholly-owned subsidiary of Enable that operates a 2,200-mile intrastate pipeline that provides natural gas transportation and storage services to customers in Oklahoma
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 U.S.
IRP	Integrated Resource Plan
kV	Kilovolt
LDC	Local distribution company involved in the delivery of natural gas to consumers within a specific geographic area
MATS	Mercury and Air Toxics Standards
MBbl/d	Thousand barrels per day
MMBtu	Million British thermal unit
MRT	Enable Mississippi River Transmission, LLC, a wholly owned subsidiary of Enable that operates a 1,600-mile interstate pipeline that provides natural gas transportation and storage services principally in Texas, Arkansas, Louisiana, Missouri and Illinois
Mustang Modernization Plan	The construction of seven new, efficient combustion turbines with generating capability of 462 MWs
MW	Megawatt
MWh	Megawatt-hour
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Corporation
NGLs	Natural gas liquids
NO_X	Nitrogen oxide
OCC	Oklahoma Corporation Commission
OG&E	Oklahoma Gas and Electric Company, wholly-owned subsidiary of OGE Energy
OGE Energy	Holding company

OGE Holdings	OGE Enogex Holdings LLC, wholly-owned subsidiary of OGE Energy, parent company of Enogex Holdings and 25.6 percent owner of Enable
OSHA	Federal Occupational Safety and Health Act of 1970
Pension Plan	Qualified defined benefit retirement plan
Ppb	Parts per billion
QF	Qualified cogeneration facility
QF contracts	Contracts with QFs and small power production producers
Regional Haze Rule	The EPA's Regional Haze Rule
Restoration of Retirement Income Plan	Supplemental retirement plan to the Pension Plan
SESH	Southeast Supply Header, LLC, in which Enable owns a 50 percent interest as of December 31, 2018, that operates an approximately 290-mile interstate natural gas pipeline from Perryville, Louisiana to southwestern Alabama near the Gulf Coast
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
U.S.	United States of America

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;
- the ability to obtain timely and sufficient rate relief to allow for recovery of items such as capital expenditures, fuel costs, operating costs, transmission costs and deferred expenditures;
- 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;
- the impact on demand for our services resulting from cost-competitive advances in technology, such as distributed electricity generation and customer energy efficiency programs;
- technological developments, changing markets and other factors that result in competitive disadvantages and create the potential for impairment of existing assets;
- 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;
- availability and prices of raw materials for current and future construction projects;
- the effect of retroactive pricing of transactions in the SPP markets or adjustments in market pricing mechanisms by the SPP;
- 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, safety laws or other regulations that may impact the cost of operations or restrict or change the way the Company operates its facilities;
- 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 cyberattacks and other catastrophic events;
- creditworthiness of suppliers, customers and other contractual parties;
- social attitudes regarding the utility, natural gas and power industries;
- identification of suitable investment opportunities to enhance shareholder returns and achieve long-term financial objectives through business acquisitions and divestitures;
- 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 this Form 10-K;
- 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" herein.

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, incorporated in August 1995 in the State of Oklahoma, is a holding company with investments in energy and energy services providers offering physical delivery and related services for both electricity and natural gas primarily in the south central U.S. The Company conducts these activities through two business segments: (i) electric utility and (ii) natural gas midstream operations.

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 represents the Company's investment in Enable through wholly owned subsidiaries and ultimately OGE Holdings. Enable was formed in 2013 and is primarily 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 Anadarko and Williston Basins. Enable has intrastate natural gas transportation and storage assets that are located in Oklahoma as well as interstate assets that extend from western Oklahoma and the Texas Panhandle to Louisiana, from Louisiana to Illinois and from Louisiana to Alabama. At December 31, 2018, the Company owned 111.0 million common units, or 25.6 percent, of Enable's outstanding common units.

The Company's principal executive offices are located at 321 North Harvey, P.O. Box 321, Oklahoma City, Oklahoma 73101-0321 (telephone 405-553-3000). At December 31, 2018, the Company had 2,292 employees, of which 90 are seconded to Enable. The Company's website address is *www.ogeenergy.com.* Through the Company's website under the heading "Investors," "SEC Filings," the Company makes available, free of charge, its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the 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. The Company's 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. Reports filed with the Securities and Exchange Commission are also made available on its website at *www.sec.gov*.

Company Strategy

The Company's mission, through OG&E and the Company's 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 customer's 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, with a particular focus 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;
- having 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;

- ensuring we have the necessary mix of generation resources to meet the long-term needs of our customers; and
- 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 four to six 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 Company also utilizes cash distributions from its investment in Enable to help 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 having 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 92 percent of its total electric operating revenues in 2018 from sales in Oklahoma and the remainder from sales in Arkansas. OG&E does not currently serve wholesale customers in either state.

OG&E's system control area peak demand in 2018 was 6,863 MWs on July 20, 2018. OG&E's load responsibility peak demand was 6,094 MWs on July 20, 2018. The following table shows system sales and variations in system sales for 2018, 2017 and 2016.

Year Ended December 31	**2018**	**2018 vs. 2017**	2017	2017 vs. 2016	2016
System sales - (*Millions of MWh*)	**28.1**	**6.8%**	26.3	(2.2)%	26.9

OG&E is subject to competition in various degrees from government-owned electric systems, municipally-owned electric systems, rural electric cooperatives and, in certain respects, from other private utilities, power marketers and cogenerators. Oklahoma law forbids the granting of an exclusive franchise to a utility for providing electricity.

Besides competition from other suppliers or marketers of electricity, OG&E competes with suppliers of other forms of energy. The degree of competition between suppliers may vary depending on relative costs and supplies of other forms of energy. 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 determinant of our competitiveness.

OKLAHOMA GAS AND ELECTRIC COMPANY
CERTAIN OPERATING STATISTICS

Year Ended December 31	**2018**	2017	2016
ELECTRIC ENERGY *(Millions of MWh)*			
Generation (exclusive of station use)	**18.2**	18.5	21.4
Purchased	**12.6**	11.0	9.6
Total generated and purchased	**30.8**	29.5	31.0
OG&E use, free service and losses	**(1.3)**	(1.4)	(1.1)
Electric energy sold	**29.5**	28.1	29.9
ELECTRIC ENERGY SOLD *(Millions of MWh)*			
Residential	**9.7**	8.8	9.3
Commercial	**8.1**	7.6	7.6
Industrial	**3.8**	3.6	3.6
Oilfield	**3.4**	3.2	3.2
Public authorities and street light	**3.1**	3.1	3.2
System sales	**28.1**	26.3	26.9
Integrated market	**1.4**	1.8	3.0
Total sales	**29.5**	28.1	29.9
ELECTRIC OPERATING REVENUES *(In millions)*			
Residential	**$ 901.0**	$ 884.1	$ 951.9
Commercial	**598.0**	588.3	573.7
Industrial	**196.7**	200.6	194.6
Oilfield	**153.2**	159.5	156.9
Public authorities and street light	**204.0**	208.0	204.3
Sales for resale	**0.2**	0.2	0.3
System sales revenues	**2,053.1**	2,040.7	2,081.7
Provision for rate refund	**(6.0)**	26.8	(33.6)
Integrated market	**48.7**	23.5	49.3
Transmission	**147.4**	151.2	143.0
Other	**27.1**	18.9	18.8
Total operating revenues	**$ 2,270.3**	$ 2,261.1	$ 2,259.2
ACTUAL NUMBER OF ELECTRIC CUSTOMERS *(At end of period)*			
Residential	**725,440**	719,441	712,467
Commercial	**97,685**	96,098	94,790
Industrial	**2,771**	2,795	2,831
Oilfield	**6,386**	6,415	6,469
Public authorities and street light	**17,090**	17,081	17,025
Total customers	**849,372**	841,830	833,582
AVERAGE RESIDENTIAL CUSTOMER SALES			
Average annual revenue	**$ 1,247.22**	$ 1,234.92	$ 1,342.88
Average annual use (kilowatt-hour)	**13,466**	12,324	13,105
Average price per kilowatt-hour (cents)	**9.26**	10.02	10.25

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 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 2018, 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.

For information concerning OG&E's recently completed and currently pending regulatory proceedings, see Note 15 in "Item 8. Financial Statements and Supplementary Data."

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. 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 or liabilities, which could have significant financial effects. See Note 1 in "Item 8. Financial Statements and Supplementary Data" for further discussion of OG&E's regulatory assets and liabilities.

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 alternative customer programs and rate options, as described below.

- 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 off-peak 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.
- The Renewable Energy Credit purchase program, a rate option that provides a "renewable energy" resource, is available as a voluntary option to all of OG&E's Oklahoma retail customers. OG&E's ownership and access to wind and solar resources makes the renewable option a possible choice in meeting the renewable energy needs of our conservation-minded customers.
- Load Reduction is a voluntary load curtailment program that provides OG&E's commercial and industrial 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 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 has 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. In May 2017, the APSC approved a settlement requiring OG&E to be regulated under a formula rate rider. The formula rate rider provides for an annual adjustment to rates approved by the APSC in the May 2017 settlement if the earned rate of return falls outside of a plus or minus 50 basis point dead-band around the allowed return on equity. Adjustments are limited to plus or minus four percent of revenue for each rate class for the 12 months preceding the projected year. The initial term for the formula rate rider is not to exceed five years, unless additional approval is obtained from the APSC.

OG&E offers several alternative customer programs and rate options, as described below.

- 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 off-peak times when demand for electricity is lowest.
- The Renewable Energy Credit purchase program, a tariff rate option that provides a "renewable energy" resource, 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.
- Load Reduction is a voluntary load curtailment program that provides OG&E's commercial and industrial 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

The OG&E-generated energy produced and the weighted average cost of fuel used, by type, for the last three years is presented below.

	Fuel Mix (A)			Fuel Cost *(In cents/Kilowatt-Hour)*		
Fuel	**2018**	2017	2016	**2018**	2017	2016
Natural gas	48%	39%	45%	**2.517**	2.821	2.488
Coal	45%	54%	48%	**2.025**	2.069	2.213
Renewable	7%	7%	7%	**—**	—	—
Total fuel	**100%**	**100%**	**100%**	**2.122**	2.211	2.199

(A) Fuel mix calculated as a percent of net MWhs generated.

The decrease in the weighted average cost of fuel in 2018 compared to 2017 was primarily due to lower natural gas prices. The increase in the weighted average cost of fuel in 2017 as compared to 2016 was primarily due to higher 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 participates in the SPP Integrated Marketplace. As part of the Integrated Marketplace, the SPP has 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 to determine which generating units will run at any given time for maximum cost-effectiveness within the SPP area. 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.

Of OG&E's 6,616 total MWs of generation capability reflected in the table in "Item 2. Properties," 3,631 MWs, or 54.9 percent, are from natural gas generation, 2,524 MWs, or 38.1 percent, are from coal generation, 449 MWs, or 6.8 percent, are from wind generation and 12 MWs, or 0.2 percent, are from solar generation.

Coal

OG&E's coal-fired units are designed to burn low sulfur western sub-bituminous coal. The combination of all 2018 coal had 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.

For the first quarter of 2019, OG&E has purchased 100 percent of its coal requirements. OG&E plans to fill the remainder of its 2019 coal needs through spot purchases and use of existing inventory. OG&E has no coal purchase contracts beyond December 2019. In 2018, OG&E purchased 4.6 million tons of coal from various Wyoming suppliers. See "Environmental Laws and Regulations" in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" 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 purchases its natural gas supply through short-term agreements. OG&E relies on a combination of natural gas call 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 owns the 120 MW Centennial, 101 MW OU Spirit and 228 MW Crossroads wind farms. OG&E's current wind power portfolio also includes purchased power contracts as listed in the table below.

Company	Location	Original Term of Contract	Expiration of Contract	MWs
CPV Keenan	Woodward County, OK	20 years	2030	152.0
Edison Mission Energy	Dewey County, OK	20 years	2031	130.0
NextEra Energy	Blackwell, OK	20 years	2032	60.0

Solar

In 2015, OG&E placed its first solar plant into service. The plant consists of two separate solar farms and is located in Oklahoma City on the site of the Mustang generating facility. The Mustang solar plant has a maximum capacity of 2.5 MWs and consists of almost 10,000 photovoltaic panels.

In the first quarter of 2018, OG&E placed its second solar plant, which is located near Covington, Oklahoma, into service. The Covington solar plant has a maximum capacity of 9.7 MWs and consists of almost 38,000 photovoltaic panels.

OG&E will continue to evaluate the need to add solar plants to its generation portfolio based on customer demand, cost and reliability.

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

Overview

Enable is a 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 U.S., including several unconventional shale resource plays and local and regional end-user markets in the U.S. Enable's assets and operations are organized into two reportable segments: (i) gathering and processing and (ii) transportation and storage. Enable's gathering and processing segment primarily provides natural gas gathering and processing to its producer customers and crude oil, condensate and produced water gathering services to its producer and refiner customers. Enable's transportation and storage segment provides interstate and intrastate natural gas pipeline transportation and storage services primarily to its producer, power plant, LDC and industrial end-user customers.

Gathering and Processing

Enable owns and operates substantial natural gas gathering and processing and crude oil, condensate and produced water gathering assets in five states. Enable's gathering and processing operations consist primarily of natural gas gathering and processing assets serving the Anadarko, Arkoma and Ark-La-Tex Basins, crude oil and condensate gathering assets serving the Anadarko Basin and crude oil and produced water assets serving the Williston Basin. Enable provides a variety of services to the active producers in its operating areas, including gathering, compressing, treating and processing natural gas, fractionating NGLs and gathering crude oil, condensate and produced water.

Enable generates revenues from producers in the basins in which it operates. For the year ended December 31, 2018, Enable's top ten natural gas producer customers accounted for approximately 70 percent of its natural gas gathered volumes. Enable's Anadarko Basin crude oil gathering systems gathers crude oil and condensate from producers, which are primarily delivered to one customer. The rates and terms of service on Enable's Anadarko Basin crude oil and condensate gathering system are regulated by the OCC. Enable's Williston Basin crude oil and produced water gathering systems serve one customer. The rates and terms of service on Enable's Williston Basin crude oil gathering systems, but not its produced water gathering systems, are regulated by the FERC. Enable's contracts typically provide for crude oil, condensate and produced water gathering services that are fee-based and for natural gas gathering and processing arrangements that are fee-based, or percent-of-liquids, percent-of-proceeds or keep-whole based.

Competition for Enable's gathering and processing systems is primarily a function of gathering rate, processing value, system reliability, fuel rate, system run time, construction cycle time and prices at the wellhead. Enable's gathering and processing systems compete with gatherers and processors of all types and sizes, including those affiliated with various producers, other major pipeline companies and various independent midstream entities. In the process of selling NGLs, Enable competes against other natural gas processors extracting and selling NGLs. Enable's primary competitors are other midstream companies who are active in the regions where Enable operates.

While the results of Enable's gathering and processing segment are not materially affected by seasonality, from time to time, its operations and construction of assets can be impacted by inclement weather.

Transportation and Storage

Enable owns and operates interstate and intrastate natural gas transportation and storage systems across nine states. Enable's transportation and storage systems consist primarily of its interstate systems, EGT and MRT, its intrastate system, EOIT, and its investment in SESH. Enable's transportation and storage assets transport natural gas from areas of production and interconnected pipelines to power plants, LDCs and industrial end users as well as interconnected pipelines for delivery to additional markets. Enable's transportation and storage assets also provide facilities where natural gas can be stored by customers.

Enable's interstate and intrastate natural gas transportation and storage systems generate revenue primarily by serving various LDCs, producers, utilities, power plants and industry end-users. For the year ended December 31, 2018, approximately 28 percent of EGT's service revenue was attributable to contracts with one customer, CenterPoint. All of EGT's firm transportation and storage contracts for CenterPoint's LDCs are scheduled to expire in March 2021. CenterPoint's LDCs have initiated proceedings before the state utility commissions in Arkansas and Oklahoma to consider whether contracts extending transportation and storage services with EGT would be more favorable than the expected results of competitive bidding for the same services. If the proposed contracts are approved, then the term for the transportation and storage services provided to CenterPoint's LDCs in Arkansas, Louisiana, Oklahoma and northeast Texas will be extended beyond March 2021, pursuant to the terms of the approved contracts.

For the year ended December 31, 2018, approximately 70 percent of MRT's service revenue was attributable to contracts with one customer, Spire Inc. MRT's firm transportation contracts representing 63 percent of Spire Inc.'s firm transportation capacity are scheduled to expire in July 2019, and 37 percent of Spire Inc.'s firm transportation capacity are scheduled to expire in July 2020. 32 percent of Spire Inc.'s firm storage contracts are scheduled to expire in May 2019, and 68 percent of Spire Inc.'s firm storage contracts are schedule to expire in May 2020. On August 3, 2018, the FERC approved a Certificate of Public Convenience and Necessity for the Spire STL Pipeline. The Spire STL Pipeline will be an additional interstate pipeline serving Spire Inc.'s affiliates in the St. Louis, Missouri market. Spire Inc. has indicated that it is targeting a 2019 in-service date for this pipeline. When the pipeline is placed into service, Enable anticipates that Spire Inc.'s LDC's need for firm transportation and storage capacity on MRT will decrease.

Enable's EGT, MRT and SESH transportation and storage services are typically provided under firm, fee-based transportation and storage agreements, with rates and terms of service regulated by the FERC. EOIT provides fee-based firm and interruptible transportation and storage services on both an intrastate and interstate basis.

Enable's interstate and intrastate pipelines compete with a variety of other interstate and intrastate pipelines in providing transportation and storage services within its operating areas. Enable's management views the principal elements of competition among pipelines as rates and terms, flexibility and reliability of service.

Customer demand for natural gas on EGT and MRT is usually greater during the winter, primarily due to LDC demand to serve residential and commercial natural gas requirements. Customer demand for natural gas transportation and storage services on EOIT is usually greater during the summer, primarily due to demand by natural gas-fired power plants to serve residential and commercial electricity requirements, including for OG&E. SESH is generally not impacted by seasonality.

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 the Company's business activities in many ways, including the handling or disposal of waste material, planning for future construction activities to avoid or mitigate harm to threatened or endangered species and requiring the installation and operation of emissions 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. Management believes that all of its operations are in substantial compliance with current federal, state and local environmental standards.

In the past, environmental regulation caused the Company to incur significant costs because the trend was to place more and more restrictions and limitations on the Company's activities. The Trump administration has delayed, reversed or proposed to repeal some of these regulations and generally has not sought to adopt new, more stringent regulations. Nonetheless, the Company continues to have obligations to take or complete action under previously adopted environmental rules, and 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 for environmental matters.

It is estimated that OG&E's total expenditures to comply with environmental laws, regulations and requirements for 2019 will be $50.0 million, of which $25.5 million is for capital expenditures. The amounts for OG&E include capital expenditures for the Dry Scrubbers at Sooner Units 1 and 2 and the conversion of Muskogee Units 4 and 5 to natural gas. It is estimated that OG&E's total expenditures to comply with environmental laws, regulations and requirements for 2020 will be $22.6 million, of which $0.2 million is for capital expenditures. Management continues to evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

For further discussion of environmental matters and capital expenditures related to environmental factors that may affect the Company, see "2018 Capital Requirements, Sources of Financing and Financing Activities," "Future Capital Requirements" and "Environmental Laws and Regulations" in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Executive Officers

The table below includes the names, titles and business experience for the most recent five years for those persons serving as Executive Officers of the Registrant as of February 20, 2019:

Name	Age		Current Title and Business Experience
Sean Trauschke	51	2015 - Present:	Chairman of the Board, President and Chief Executive Officer of OGE Energy Corp.
		2014 - 2015:	President of OGE Energy Corp.
		2014:	Vice President and Chief Financial Officer of OGE Energy Corp.
E. Keith Mitchell	56	2015 - Present:	Chief Operating Officer of OG&E
		2014 - 2015:	Executive Vice President and Chief Operating Officer of Enable Midstream Partners, LP
Stephen E. Merrill	54	2014 - Present:	Chief Financial Officer of OGE Energy Corp.
		2014:	Executive Vice President of Finance and Chief Administrative Officer of Enable Midstream Partners, LP
Sarah R. Stafford	37	2018 - Present:	Controller and Chief Accounting Officer of OGE Energy Corp.
		2016 - 2018:	Accounting Research Officer of OGE Energy Corp.
		2014 - 2016:	Senior Manager - Ernst & Young, LLP
Patricia D. Horn	60	2014 - Present:	Vice President - Governance and Corporate Secretary of OGE Energy Corp.
		2014:	Vice President - Governance, Environmental and Corporate Secretary of OGE Energy Corp.
Jean C. Leger, Jr.	60	2014 - Present:	Vice President - Utility Operations of OG&E
Kenneth R. Grant	54	2016 - Present:	Vice President - Sales and Marketing of OG&E
		2015:	Vice President Marketing and Product Development of OG&E
		2014 - 2015:	Managing Director Tech Solutions & Ops of OG&E
Cristina F. McQuistion	54	2017 - Present:	Vice President - Chief Information Officer of OG&E
		2016 - 2017:	Vice President - Chief Information Officer and Utility Strategy of OG&E
		2014 - 2015:	Vice President - Strategic Planning, Performance Improvement and Chief Information Officer of OG&E
		2014:	Vice President - Strategic Planning, Performance Improvement and Chief Information Officer of OGE Energy Corp. and OG&E
Kenneth A. Miller	52	2019 - Present:	Vice President - Regulatory and State Government Affairs of OG&E
		2014 - 2018:	State Treasurer of Oklahoma
Jerry A. Peace	56	2016 - Present:	Vice President - Integrated Resource Planning and Development of OG&E
		2014 - 2015:	Chief Generation Planning and Procurement Officer of OG&E
		2014:	Chief Risk Officer of OGE Energy Corp.
William H. Sultemeier	51	2017 - Present:	General Counsel of OGE Energy Corp.
		2016:	Partner - Jones Day
		2014-2015:	Shareholder - Greenberg Traurig, LLP
Charles B. Walworth	44	2014 - Present:	Treasurer of OGE Energy Corp.
		2014:	Assistant Treasurer of OGE Energy Corp.

No family relationship exists between any of the Executive Officers of the Registrant. Messrs. Trauschke, Merrill, Sultemeier, Walworth and Mses. Horn and Stafford 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 16, 2019.

Messrs. Trauschke and Merrill are members of the Board of Directors of Enable GP, LLC, the general partner of Enable.

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 addition, OG&E's jurisdictions have fuel adjustment clauses that permit OG&E to recover fuel costs through rates without a general rate case, subject to a later determination that such fuel costs were prudently incurred. If the state regulatory commissions determine that the fuel costs were not prudently incurred, recovery could be disallowed.

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 authorized 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.

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. No rules are currently in effect that require us to reduce our greenhouse gas emissions, but if such rules were to become effective, 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.

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 OG&E can handle or dispose of its wastes or requiring remedial action to mitigate pollution conditions that may be caused by its operations or that are attributable to former operators. OG&E may be unable to recover these costs from insurance or other regulatory mechanisms. 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 further discussion of environmental matters that may affect the Company, see "Environmental Laws and Regulations" in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

We may not be able to recover the costs of our substantial investment in capital improvements and additions.

OG&E has recently made substantial investments in capital improvements and additions, including the installation of environmental upgrades and retrofits. OG&E's business plan calls for extensive investment in capital improvements and additions, including 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 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 of December 31, 2018, OG&E had invested $504.3 million in the Dry Scrubbers at Sooner Units 1 and 2 and is currently seeking recovery of its investment with the OCC.

The regional power market in which OG&E operates has changing transmission regulatory structures, which may affect the transmission assets and related revenues and expenses.

OG&E currently owns and operates transmission and generation facilities as part of a vertically integrated utility. OG&E is a member of the SPP regional transmission organization and has transferred operational authority (but not ownership) of OG&E's transmission facilities to the SPP. The SPP has implemented 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 Sales in its Consolidated Financial Statements. OG&E's revenues, expenses, assets and liabilities may be adversely affected by changes in the organization, operation and regulation 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 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 consolidated financial position, 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 NERC as the national energy reliability organization. The NERC 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. One of OG&E's regulators, the NERC, has comprehensive regulations and standards related to the reliability and security of our operating systems, and is continuously developing additional mandatory compliance requirements for the utility industry. The increasing development of NERC rules and standards will increase compliance costs and our exposure for potential violations of these standards.

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, 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 generation, transmission and distribution assets are subject to operational risks that could result in unscheduled plant outages, unanticipated operation and maintenance expenses, increased purchase power costs, accidents and third-party liability.

OG&E owns and operates coal-fired, natural gas-fired, wind-powered and solar-powered generating assets. Operation of electric generation, transmission and distribution assets involves risks that can adversely affect energy output and efficiency levels or that could result in loss of human life, significant damage to property, environmental pollution and impairment of OG&E's operations. 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.

The occurrence of any of these events, if not fully covered by insurance, could have a material effect on our consolidated financial position and results of operations. Further, when unplanned maintenance work is required on power plants or other equipment, OG&E will not only incur unexpected maintenance expenses, but it may also have to make spot market purchases of replacement electricity that could exceed OG&E's costs of generation or be forced to retire a generation unit if the cost or timing of the maintenance is not reasonable and prudent. If OG&E is unable to recover any of these increased costs in rates, it could have a material adverse effect on our financial performance.

Changes in technology, regulatory policies and customer electricity consumption may cause our assets to be less competitive and impact our results of operations.

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. OG&E's widespread use of Smart Grid technology allowing for two-way communications between the utility and its customers could enable the entry of technology companies into the interface between OG&E and its customers, resulting in unpredictable effects on our current business.

Reductions in customer electricity consumption, thereby reducing utility electric sales, could result from increased deployment of renewable energy technologies as well as increased efficiency of household appliances, among other general efficiency gains in technology. However, this potential reduction in load would not reduce our need for ongoing investments in our infrastructure to reliably serve our customers. Continued utility infrastructure investment without increased electricity sales could cause increased rates for customers, potentially resulting in further reductions in electricity sales and reduced profitability.

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 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.

Economic conditions may be impacted 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 consolidated 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 cybersecurity 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 cybersecurity attacks. Our generation and transmission systems are part of an interconnected system. Therefore, a disruption caused by the impact of a cybersecurity 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.

Security threats continue to evolve and adapt. We and our third-party vendors have been subject to, and will likely continue to be subject to, attempts to gain unauthorized access to systems, or confidential data, or to disrupt operations. None of these attempts has individually or in aggregate resulted in a security incident with a material impact on our financial condition or results of operations. Despite implementation of security and control measures, there can be no assurance that we will be able to prevent the unauthorized access of our systems and data, or the disruption of our operations, either of which could have a material impact. Our security procedures, which include among others, virus protection software, cybersecurity 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 cybersecurity attacks on our systems, which could adversely impact our operations.

We maintain property, casualty and cybersecurity 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 or 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 or 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, prolonged droughts and the occurrence of wildfires, 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, prolonged droughts and the occurrence of wildfires 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 flows.

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, 2018, 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.

Finally, the Company provides retirement benefits and retiree health care benefits to 90 employees seconded to Enable. If the seconding agreement was terminated, and those employees were no longer employed by the Company, and lump sum payments were made to those employees, the Company would recognize a settlement or curtailment of the pension/retiree health care charges, which would increase expense at the Company by $20.4 million. Settlement and curtailment charges associated with the Enable seconded employees are not reimbursable to the Company by Enable. The seconding agreement can be terminated by mutual agreement of the Company and Enable or solely by the Company upon 120 day's notice.

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, 32 percent of our current employees will meet the eligibility requirements to retire. 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 utilizes 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, 2018, the Company and its subsidiary had outstanding indebtedness and other liabilities of $6.7 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 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 are in compliance with the financial covenants set forth in our revolving credit agreements and the indentures governing our debt securities, we may be able to incur substantial additional indebtedness. If we incur additional indebtedness, the related risks that we 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 and retail distribution 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

The Company does not control Enable and therefore is not able to cause or prevent certain actions by Enable. The general partnership of Enable is equally controlled by the Company and CenterPoint.

Enable has its own governing board; therefore, the Company is not able to exercise control over Enable. Accordingly, the Company is unable to cause or prevent certain actions by Enable. Further, the Company cannot control the actions of the other general partner, CenterPoint. Our interests may not align with those of CenterPoint, and this lack of control could adversely impact our investment in Enable.

A portion of our earnings and operating cash flows are based 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 Enable can distribute on its units principally depends upon the amount of cash generated from its operations, which will fluctuate from quarter to quarter based on, among other things:

- the fees and gross margins it realizes with respect to the volume of natural gas, NGLs and crude oil that it handles;
- the prices of, levels of production of, and demand for natural gas, NGLs and crude oil;
- the volume of natural gas, NGLs and crude oil it gathers, compresses, treats, dehydrates, processes, fractionates, transports and stores;
- 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 companies offering midstream services;
- adverse effects of governmental and environmental regulation;
- the level of its operation and maintenance expenses and general and administrative costs; and
- prevailing economic conditions.

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

- the level and timing of capital expenditures it makes;
- the cost of acquisitions;
- its debt service requirements and other liabilities;
- fluctuations in working capital needs;
- its ability to borrow funds and access capital markets;
- restrictions contained in its debt agreements;
- the amount of cash reserves established by its general partner;
- distributions paid on its Series A Preferred Units; and
- other business risks affecting its cash levels.

Enable's contracts are subject to renewal risk.

As contracts with Enable's existing suppliers and customers expire, Enable negotiates extensions or renewals of those contracts or enters into new contracts with other suppliers and customers. Enable may be unable to extend or renew existing contracts or enter into new contracts on favorable commercial terms, if at all. Depending on prevailing market conditions at the time of an extension or renewal, gathering and processing customers with fee-based contracts may desire to enter into contracts under different fee arrangements, and gathering and processing customers with contracts that contain minimum volume commitments may desire to enter into contracts without minimum volume commitments. Likewise, Enable's transportation and storage customers may choose not to extend or renew expiring contracts based on the economics of the related areas of production. To the extent Enable is unable to renew or replace its expiring contracts on terms that are favorable to Enable, if at all, or successfully manage its overall contract mix over time, its financial position, results of operations and ability to make cash distributions to unitholders, including us, could be adversely affected.

As further discussed in "Natural Gas Midstream Operations - Enable Midstream Partners" in "Item 1. Business," in 2018, the FERC approved Spire Inc.'s STL Pipeline, an interstate pipeline that is currently under construction and will serve the St. Louis, Missouri market. When this pipeline is placed into service, Enable anticipates that Spire Inc.'s need for firm transportation and storage capacity on Enable's pipelines will decrease.

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

For the year ended December 31, 2018, 61 percent of Enable's natural gas gathered volumes were attributable to the affiliates of Continental Resources, Inc., Vine Oil and Gas, GeoSouthern Energy Corporation, XTO Energy Inc. and Tapstone Corporation and 51 percent of its transportation and storage service revenues were attributable to affiliates of CenterPoint, Spire Inc., Continental Resources, Inc., American Electric Power Co. and the Company. The loss of all or even a portion of the gathering and processing or transportation and storage services for any of these customers (as discussed above and in "Item 1. Business" regarding Spire Inc.), 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 financial position, results of operations and ability to make cash distributions to unitholders, including us.

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

The businesses of Enable are dependent on the drilling and production of natural gas and crude oil. Enable has no control over the level of drilling activity in its areas of operation, or the amount of natural gas, NGLs and crude oil reserves associated with wells connected to its systems. In addition, as the rate at which production from wells currently connected to its system naturally declines over time, its gross margin associated with those wells will also decline. 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, NGLs and crude oil supplies. The primary factors affecting its ability to obtain new supplies of natural gas, NGLs and crude oil and attract new customers to its assets are the level of successful drilling activity near its systems, its ability to compete for volumes from successful new wells and its ability to expand its 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 adversely affect its financial position, results of operations and ability to make cash distributions to unitholders, including us. Enable has no control over producers or their 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, the regulation of hydraulic fracturing and the regulation of air emissions; 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, NGLs and crude oil reserves. Drilling and production activity generally decreases as commodity prices decrease. In general terms, the prices of natural gas, NGLs, 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 and other factors, even if new reserves are known to exist in areas served by Enable's assets, producers may choose not to develop those reserves. Declines in natural gas, NGLs 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. Sustained low natural gas, NGLs or crude oil prices could also lead producers to shut in production from their 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 adversely affect its financial position, results of operations and ability to make 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 and in its processing plants, as several of the formations in the unconventional resource plays in which Enable operates generally have 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.

Enable's industry is highly competitive and increased competitive pressure could adversely affect its financial position, results of operations and ability to make cash distributions to unitholders, including us.

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 energy 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 Enable's 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 or crude oil 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 storage services. All of these competitive pressures could adversely affect its financial position, results of operations and ability to make cash distributions to unitholders, including us.

Enable derives a substantial portion of its gross margin from subsidiaries through which it holds a substantial portion of its assets.

Enable derives a substantial portion of its gross margin 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 its limited partners depends primarily on its cash flow rather than on its profitability, which may prevent Enable from making distributions, even during periods in which it records net income.

The amount of cash Enable has available for distribution depends primarily upon its cash flow rather than on profitability. Profitability is affected by non-cash items but cash flow is not. 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 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 investments in capital improvements and additions. Capital expenditures could range from approximately $325 million to $425 million for the year ending December 31, 2019.

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 and availability 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 is expanded or a new pipeline is constructed, the construction may occur over an extended period of time, and Enable may 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 financial position, results of operations and ability to make cash distributions to its unitholders, including us.

In connection with its capital investments, Enable may estimate, or 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 either in volume or timing due to numerous uncertainties inherent in estimating future production. To the extent estimates of the volume of new production are inaccurate, new facilities may not be able to attract sufficient throughput to achieve expected investment return, which could adversely affect its financial position, results of operations and ability to make cash distributions to unitholders, including us. To the extent estimates in the timing of new production are inaccurate, new facilities may be constructed in advance of the actual need for capacity or may not be constructed in time to accommodate volume flows, which could adversely affect Enable's financial position, results of operations and ability to make cash distributions to unitholders, including us. 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 financial position, results of operations and ability to make cash distributions to unitholders, including us, could be adversely affected.

Natural gas, NGLs and crude oil prices are volatile, and changes in these prices could adversely affect Enable's financial position, results of operations and its ability to make cash distributions to unitholders, including us.

Enable's financial position, results of operations and ability to make cash distributions to us could be negatively affected by adverse changes 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 natural gas processing arrangements expose Enable to commodity price fluctuations. In 2018, six percent, 27 percent and 67 percent of Enable's processing plant inlet volumes consisted of keep-whole arrangements, percent-of-proceeds or percent-of-liquids and fee-based, respectively. If the price at which Enable sells natural gas or NGLs is less than the cost at which it purchases natural gas or NGLs under these arrangements, then its financial position, results of operations and ability to make cash distributions to unitholders, including us, could be adversely affected.

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, Enable's financial position, results of operations and ability to make cash distributions to unitholders, including us, could be adversely affected to the extent the price of NGLs decreases in relation to the price of natural gas.

Enable's exposure to credit risks of its customers, and any material nonpayment or nonperformance by its customers could adversely affect its financial position, results of operations and ability to make cash distributions to unitholders, including us.

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 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. As of December 31, 2018, approximately 44 percent of Enable's aggregate contracted firm transportation capacity on EGT and MRT and 45 percent of its aggregate contracted firm storage capacity on EGT and MRT 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 Enable's costs increase and it is not able to recover any shortfall of revenue associated with its negotiated rate contracts, the cash flow realized by its systems could decrease and, therefore, the cash Enable has available for distribution to its unitholders, including us, could also decrease.

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 financial position, results of operations and its ability to make cash distributions to us could be adversely affected.

Enable depends upon (i) third-party pipelines to deliver natural gas to, and take natural gas from, its natural gas transportation systems, (ii) third-party pipelines and other facilities to take crude oil from its crude oil gathering systems, and, in some cases, (iii) third-party facilities to process natural gas from its gathering systems. It also depends on third-party facilities to transport and fractionate NGLs that are delivered to the third party at the tailgates of its processing plants. Fractionation is the separation of the heterogeneous mixture of extracted NGLs into individual components for end-use sale. For example, an outage or disruption on certain pipelines or fractionators operated by a third party could result in the shutdown of certain of Enable's processing plants and gathering systems, and a prolonged outage or disruption could ultimately result in a reduction in the volume of natural gas Enable gathers and 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 financial position, results of operations and ability to make cash distributions to unitholders, including 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 for a specific period of time on lands owned by governmental agencies, American Indian tribes or other third parties, including on American Indian allotments, title to which is held in trust by the U.S. 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 financial position, 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 adversely affect the success of its operations and financial position, results of operations and ability to make cash distributions to unitholders, including us.

Enable conducts a portion of its operations through joint ventures with third parties, including Enbridge Inc., DCP Midstream Partners, LP, CVR Refining, 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 adversely affect its financial position and results of operations ability to make cash distributions to unitholders, including us. 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, Enbridge Inc. could 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 Enbridge Inc. As of December 31, 2018, CenterPoint owns a 54.0 percent of Enable's common units, 100.0 percent of its Series A Preferred Units 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 LLC Agreement), if, at any time, CenterPoint has a right to receive less than 50 percent of Enable's distributions through its interests in Enable and in the general partner, or does not have the ability to exercise certain control rights, Enbridge Inc. could have the right to purchase Enable's interest in SESH at fair market value, subject to certain exceptions.

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

Long-lived assets, including intangible assets with finite useful lives and property, plant and equipment, are evaluated for impairment when events or changes in circumstances indicate that the carrying amount may not be recoverable. An impairment of long-lived assets is recognized if the carrying amount is not recoverable and exceeds fair value.

Equity method investments are evaluated for impairment when events or circumstances indicate that the carrying value of the investment might not be recoverable. An impairment of an equity method investment is recognized if the fair value of the investment as a whole, and not the underlying assets, has declined and the decline is other than temporary. An example of an investment that Enable accounts for under the equity method is its investment in SESH. If Enable enters into additional joint ventures, it could have additional equity method investments.

Goodwill is evaluated for impairment on an annual basis as well as when events or circumstances change that would more likely than not reduce the fair value of a reporting unit to below its carrying amount. An impairment of goodwill is recognized if the carrying value of a reporting unit exceeds its fair value and the carrying amount of that reporting unit's goodwill exceeds the implied value of that goodwill. As of December 31, 2018, Enable has goodwill of $98 million as a result of the acquisitions of Velocity Holdings, LLC in the fourth quarter of 2018 and Align Midstream, LLC in the fourth quarter of 2017.

Enable could experience future events or circumstances that result in an impairment of long-lived assets, including intangible assets, equity method investments, or goodwill. If Enable recognizes an impairment, it would 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. As a result, an impairment could have an adverse effect on Enable's results of operations and 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 affect its financial position, 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 and farm and utility equipment;
- leaks of natural gas, NGLs, crude oil and other hydrocarbons or losses of natural gas, NGLs 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 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 adversely affect Enable's results of 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. Enable has business interruption insurance coverage for some but not 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 Enable's facilities may not be sufficient to restore the loss or damage without adversely affecting its financial position, 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 adversely affect its financial position, results of operations and its ability to make cash distributions to unitholders, including us.

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'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 its business. If Enable is unable to successfully attract and retain an appropriately qualified workforce, its results of operations could be negatively affected.

As of December 31, 2018, Enable has 90 employees who are participants under OGE Energy Corp.'s defined benefit and retiree medical plans, who are seconded to the Partnership, subject to certain termination rights of the Partnership and OGE Energy Corp. If seconding is terminated, employees of OGE Energy Corp. 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 ability to grow is dependent in part on its ability to access external financing sources on acceptable terms.

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 significantly upon external financing sources, including commercial bank borrowings and the issuance of debt and equity securities, to fund acquisitions and expansion capital expenditures. To the extent Enable or its operating subsidiaries are unable to finance growth externally or through internally generated cash flows, Enable's and its operating subsidiaries' cash distribution policy may significantly impair Enable's and its operating subsidiaries' ability to grow. In addition, because Enable and its operating subsidiaries distribute all available cash, Enable's and 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.

Enable depends in part on access to the capital markets and other external financing sources to fund its expansion capital expenditures, although Enable has also increasingly relied on cash flow generated from its operations to fund its expansion capital expenditures. Historically, unit prices of midstream master limited partnerships have experienced periods of volatility. In addition, because Enable's common units are yield-based securities, rising market interest rates could impact the relative attractiveness of its common units to investors. As a result of capital market volatility, Enable may be unable to issue equity or debt on satisfactory terms, or at all, which may limit its ability to expand its operations or make future acquisitions.

In the first quarter of 2016, CenterPoint announced that it was evaluating strategic alternatives for its investment in Enable. In the first quarter of 2018, CenterPoint disclosed that it had decided not to pursue a sale or spin-off qualifying under Section 355 of the Code at that time and that, while a transaction for all of its interests in Enable was not viable at that time, it may pursue such a transaction if it becomes viable in the future. CenterPoint also disclosed that it may reduce its investment in Enable through a sale of all or a portion of Enable's common units it owns in the public equity markets or otherwise, subject to certain limitations. CenterPoint's disclosure, as well as any sales by CenterPoint of the common units it holds in the public equity markets, could have an adverse impact on the market for Enable common units, including Enable's ability to issue equity on favorable terms to fund Enable's capital needs or at all.

Enable's merger and acquisition activities may not be successful or may result in completed acquisitions that do not perform as anticipated, which could adversely affect its financial position, results of operations or future growth.

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.

In addition, Enable's growth strategy includes, in part, the ability to make acquisitions on economically acceptable terms. If Enable is unable to make acquisitions or if its acquisitions do not perform as anticipated, Enable's future growth may be adversely affected.

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

As of December 31, 2018, Enable had approximately $2.9 billion of long-term debt outstanding, excluding the premiums, discounts and unamortized debt expense on senior notes. In addition, as of December 31, 2018, Enable had $649.0 million outstanding under its commercial paper program and $500.0 million outstanding under its 2019 notes, excluding unamortized debt expense. Enable also has a $1.75 billion revolving credit facility for working capital, capital expenditures and other partnership purposes, including acquisitions, with approximately $250.0 million in borrowings outstanding and $848.0 million remaining available as of February 1, 2019. Enable has 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 their debt will depend upon, among other things, its future financial and operating performance, which will be affected by prevailing economic conditions, commodity prices and financial, business, regulatory and other factors, some of which are beyond its control. If operating results are not sufficient to service Enable's and its operating subsidiaries' current or future indebtedness, Enable 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 financial condition, results of operations and ability to make cash distributions to its unitholders, including us.

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 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, both CenterPoint and the Company are prohibited from, directly or indirectly, owning, operating, acquiring or investing in any business engaged in midstream operations located within the U.S., other than through Enable. This requirement applies to both CenterPoint and the Company for so long as either CenterPoint or the Company holds any interest in Enable's general partner or at least 20 percent of its common units. However, if CenterPoint or the Company acquires any business with midstream operations assets that have a value in excess of $50.0 million (or $100.0 million in the aggregate with such party's other acquired midstream operations assets that have not been offered to Enable), the acquiring party will be required to offer to Enable such assets 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 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 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 an effective system of internal controls are not successful, it is unable to maintain adequate controls over its financial processes and reporting in the future or it is unable to comply with its obligations under Section 404 of the Sarbanes-Oxley Act of 2002, 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.

Cybersecurity attacks or other disruptions of Enable's systems, networks and technology could adversely impact Enable's financial position, results of operations and ability to make cash distributions to unitholders, including us.

Enable has become increasingly dependent on the systems, networks and technology that it uses to conduct almost all aspects of its business, including the operation of its gathering, processing, transportation and storage assets, the recording of commercial transactions and the reporting of financial information. Enable depends on both its own systems, networks and technology as well as the systems, networks and technology of its vendors, customers and other business partners. Any disruption of these systems, networks and technology could disrupt the operation of Enable's business. Disruptions can result from a variety of causes, including natural disasters, the failure of software or equipment and manmade events, such as cybersecurity attacks or information security breaches. Cybersecurity attacks and information security breaches could result in the unauthorized use of confidential, proprietary or other information and in the disruption of Enable's critical business functions and operations, adversely affecting its reputation and subjecting it to possible legal claims and liability. In addition, Enable is not fully insured against all cybersecurity risks.

As cybersecurity attacks continue to evolve, Enable may be required to expend significant additional resources to continue to modify or enhance its protective measures or to investigate and remediate any vulnerabilities to cybersecurity attacks. In particular, Enable's implementation of various procedures and controls to monitor and mitigate security threats and to increase security for its personnel, information, facilities and infrastructure may result in increased capital and operating costs. To date Enable has not experienced any material losses relating to cybersecurity attacks; however, there can be no assurance that it will not suffer such losses in the future. Consequently, it is possible that any of these occurrences, or a combination of them, could adversely affect Enable's financial position, results of operations and ability to make cash distributions to unitholders, including us.

Terrorist attacks or other physical security threats could adversely affect Enable's business.

Enable's gathering, processing, transportation and storage assets may be targets of terrorist activities or other physical security threats that could disrupt its ability to conduct its business. It is possible that any of these occurrences, or a combination of them, could adversely affect Enable's financial position, results of operations and ability to make cash distributions to unitholders, including us. In addition, any physical damage to Enable's assets resulting from acts of terrorism may not be fully covered by Enable's insurance.

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 Enable's 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 ability to make cash distributions to unitholders, including us.

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 American Indian tribal lands. Certain approval procedures may require preparation of archaeological surveys, wetland delineations, endangered species surveys and other studies to assess the environmental impact of new sites or the expansion of existing sites. Compliance with these regulatory requirements may be expensive and may significantly lengthen the time required to prepare applications and to receive authorizations and consequently could disrupt Enable's project construction schedules.

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 financial position, 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. For instance, in May 2016, the EPA issued final standards governing methane emissions imposing more stringent controls on methane and volatile organic compounds emissions at new and modified oil and natural gas production, processing, storage and transmission facilities. These rules have required changes to Enable's operations, including the installation of new equipment to control emissions. Following the change in presidential administrations, there have been attempts to modify these regulations, and litigation concerning the regulations is ongoing. As a result, Enable cannot predict the scope of any final methane regulatory requirements or the cost to comply with such requirements. However, several states are pursuing similar measures to regulate emissions of methane from new and existing sources. There are significant capital, operating and other costs associated with compliance with these environmental statutes, rules and regulations. Future federal and state regulations relating to Enable's gathering and processing, transmission and storage operations remain a possibility and could result in increased compliance costs on Enable's operations. Furthermore, if new or more stringent federal, state or local legal restrictions are adopted in areas where Enable's oil and natural gas exploration and production customers operate, they 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 could adversely affect demand for Enable's services to those customers.

There is inherent risk of the incurrence of environmental costs and liabilities in Enable's operations due to the handling of natural gas, NGLs, crude oil and produced water as well as air emissions related to its operations and historical industry operations and waste disposal practices. These matters 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 and transportation 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 and waste water injection wells could result in reductions or delays in natural gas production by Enable's customers, which could adversely affect its financial position, results of operations and ability to make cash distributions to its unitholders, including us.

Hydraulic fracturing is a common practice that is used by many of Enable's customers to stimulate production of natural gas and crude 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. 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. In past sessions, Congress has considered, but not passed, 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. The EPA has issued regulations and guidance for hydraulic fracturing operations under several statutes.

Some states have adopted, and other states have considered 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 entirely. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where Enable's oil and natural gas exploration and production customers operate, they 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 Enable's services to those customers.

State and federal regulatory agencies have also focused on a possible connection between the operation of injection wells used for oil and gas waste disposal and seismic activity. Similar concerns have been raised that hydraulic fracturing may also contribute to seismic activity. When caused by human activity, such events are called induced seismicity. In March 2016, the U.S. Geological Survey identified six states with the most significant hazards from induced seismicity, including Oklahoma, Kansas, Texas, Colorado, New Mexico and Arkansas. In March 2017, the U.S. Geological Survey produced an updated seismic hazard survey that forecasted lower earthquake rates in regions of induced activity but still showed significantly elevated hazards in the central and eastern U.S. In light of these concerns, some state regulatory agencies have modified their regulations or issued orders to address induced seismicity. For example, the OCC has implemented volume reduction plans, and at times required shut-ins, for disposal wells injecting wastewater from oil and gas operations into the Arbuckle formation. In February 2018, the OCC revised well completion seismicity guidelines for operators in the South Central Oklahoma Oil Province and the Sooner Trend Anadarko Basin Canadian and Kingfisher Counties to reduce the threshold of seismic readings required to suspend hydraulic fracturing operations in some circumstances. Certain environmental and other groups have also suggested that additional federal, state and local laws and regulations may be needed to more closely regulate the hydraulic fracturing process. Enable cannot predict whether additional federal, state or local laws or regulations applicable to hydraulic fracturing will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. Increased regulation and attention given to induced seismicity could lead to greater opposition to, and litigation concerning, oil and gas activities utilizing hydraulic fracturing or injection wells for waste disposal. Additional legislation or regulation could also lead to operational delays or increased operating costs for Enable's customers, which in turn could reduce the demand for Enable's services.

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 U.S. on an annual basis, which include certain of Enable's operations. Additional rules, such as the updates to the oil and gas new source performance standard requirements finalized by the EPA in May 2016, 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. Following the change in presidential administrations, there have been attempts to modify these regulations, and litigation concerning the regulations is ongoing. As a result, Enable cannot predict the scope of any final methane regulatory requirements or the cost to comply with such requirements. If upheld, 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. From time to time, the U.S. Congress has considered adopting legislation to limit greenhouse gases emissions. A number of state and regional efforts have also emerged that are aimed at tracking and/or reducing greenhouse gas emissions by means of cap and trade programs. These programs typically require major sources of greenhouse gas emissions to acquire and surrender emission allowances in return for emitting those greenhouse gas emissions. Any such future laws and regulations imposing reporting obligations on, or limiting emissions of greenhouse gases could require Enable to incur costs to reduce emissions of greenhouse gases. Substantial limitations on greenhouse gas 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 adversely affect the demand for Enable's services and its financial position, results of operations and ability to make cash distributions to unitholders, including us.

Increased regulatory-imposed costs may also increase the cost of consuming, and thereby reduce demand for, the products that Enable gathers, treats and transports. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that oil and gas will continue to represent a major share of global energy use through 2040, and other private sector studies project continued growth in demand for the next two decades.

Finally, 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 adversely affect Enable's results of operations.

Enable's operations are subject to extensive regulation by federal regulatory authorities. Changes or additional regulatory measures adopted by such authorities could adversely affect its financial position, 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 position, results of operations and ability to make cash distributions to its unitholders, including us.

Enable's natural gas interstate pipelines are regulated by the FERC under the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and the Energy Policy Act of 2005. Generally, the 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.

Should Enable fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, it could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, the FERC has civil penalty authority under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978 to impose penalties for current violations of up to approximately $1.3 million per day for each violation and possible criminal penalties of up to approximately $1.3 million per violation.

The 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 the FERC. Certain minor expansions are authorized by blanket certificates that the 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 Enable will not be able to pursue these projects or that they will be constructed in a manner or with capital requirements that Enable 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.

The FERC conducts audits to verify compliance with the 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. The 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 the FERC finds that an agreement, in whole or part, is materially non-conforming, it could reject the agreement or require Enable to seek modification, or alternatively require Enable to modify its 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 Enable's intrastate pipelines and for services offered at certain of Enable's storage facilities are subject to the jurisdiction of the 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 the FERC at least once every five years.

Enable's crude oil gathering systems in the Williston Basin are subject to common carrier regulation by the FERC under the Interstate Commerce Act. The Interstate Commerce Act requires that Enable maintain tariffs on file with the FERC setting forth the rates Enable charges for providing transportation services, as well as the rules and regulations governing such services. The Interstate Commerce Act also 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 FERC-regulated crude oil gathering systems may protest its tariff filings, file complaints against its existing rates, or the FERC can investigate Enable's rates on its own initiative. If 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.

On December 22, 2017, the 2017 Tax Act was enacted, which reduced the highest marginal U.S. federal corporate income tax rate from 35 percent to 21 percent for tax years beginning after December 31, 2017. In a series of related issuances in 2018, the FERC revised its policy so that it will no longer permit pipelines organized as master limited partnerships to recover an income tax allowance in their cost-of-service rates and proposed rules for implementing this revised policy and the corporate income tax rate reduction pursuant to the 2017 Tax Act with respect to natural gas pipeline rates. In July 2018, the FERC denied requests for rehearing of the policy statement relating to recovery of an income tax allowance (although it indicated that a master limited partnership will not be precluded in a future proceeding from arguing and providing evidentiary support that it is entitled to an income tax allowance and demonstrating that its recovery of an income tax allowance does not result in a double-recovery of investors' income tax costs). Also in July 2018, the FERC adopted proposed rules that require all FERC-regulated natural gas pipelines that have cost-based rates for service to make a one-time Form No. 501-G filing providing certain financial information that will allow the FERC and other stakeholders to evaluate the impacts of the revised policy and the corporate income tax rate reduction on each individual pipeline's rates, and to select one of four options: file a limited Natural Gas Act of 1938 Section 4 filing reducing its rates only as required related to the revised policy and the 2017 Tax Act, commit to filing a general Natural Gas Act of 1938 Section 4 rate case in the near future, file a statement explaining why an adjustment to rates is not needed, or take no other action. EGT filed its Form No. 501-G on October 11, 2018 and explained why a reduction to rates is not warranted. On November 8, 2018, SESH filed its Form No. 501-G and indicated it contemporaneously filed a limited Section 4 rate reduction filing as required by the rules described above. As MRT had already filed a rate proceeding under Natural Gas Act of 1938 Section

4 pursuant to a schedule agreed upon in the settlement of MRT's last rate case, MRT was not required to make any filing on the FERC's Form No. 501-G.

The FERC's revised policy statement requires the reduced maximum corporate tax rate to be reflected in initial oil cost-of-service rates and cost-of-service rate changes going forward and in future filings of Page 700 of FERC Form No. 6. The FERC will consider the information provided by pipelines in Page 700 of FERC Form No. 6 in its 2020 five-year review of the oil pipeline index level.

Although Enable cannot predict the ultimate impact of the policy statement and final rules, the cost-of-service rates Enable is permitted to charge their customers for transportation and storage services could be impacted when MRT or if EGT files a limited or general Natural Gas Act of 1938 Section 4 rate filing or if the FERC or customers challenge the cost-of-service rates that EGT is authorized to charge. Enable also cannot predict the outcome of the 2020 oil pipeline index five-year review, but the rates Enable is permitted to charge its customers for cost-of-service based crude oil transportation services could be impacted. If the FERC requires Enable to establish new tariff rates for either Enable's natural gas or crude oil pipelines that reflect a lower federal corporate income tax rate and the revised policy statement, it is possible the rates would be reduced, which could adversely affect Enable's financial position, results of operations and ability to make cash distributions to Enable's unitholders, including us.

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

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 systems are generally exempt from the jurisdiction of the FERC under the Natural Gas Act, and its crude oil gathering system in the Anadarko Basin is generally exempt from the jurisdiction of FERC under the Interstate Commerce Act. Nevertheless, 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 Enable's facilities it considers to be engaged in natural gas gathering or a formal determination with respect to its facilities that it considers to be engaged in intrastate crude oil gathering, Enable believes that its natural gas gathering facilities meet the traditional tests that the FERC has used to determine that a pipeline is a natural gas gathering pipeline and Enable's intrastate crude oil gathering facilities meet the traditional tests that the FERC has used to determine that a pipeline is not engaged in interstate crude oil transportation. The distinction between FERC-regulated facilities, however, has been the subject of substantial litigation, and the FERC determines whether facilities are subject to regulation under the Natural Gas Act or the Interstate Commerce Act on a case-by-case basis, so the classification and regulation of its 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, the rates for, and terms and conditions of, services provided by such facility would be subject to regulation by the FERC. 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 ability to make cash distributions to its unitholders, including us. In addition, if any of Enable's facilities were found to have provided services or otherwise operated in violation of the Natural Gas Act, Natural Gas Policy Act or Interstate Commerce Act 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 and intrastate crude oil gathering may receive greater regulatory scrutiny at the state level; therefore, these 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 compliance with pipeline safety laws and regulations, pipeline integrity and other similar programs and related repairs.

Certain of Enable's pipeline operations are subject to pipeline safety laws and regulations. The U.S. Department of Transportation's Pipeline and Hazardous Materials Safety Administration regulates safety requirements for the design, construction, maintenance and operation of its jurisdictional natural gas and hazardous liquids pipeline facilities. All of Enable's interstate and intrastate natural gas transportation pipeline facilities are Pipeline and Hazardous Materials Safety Administration jurisdictional and certain of Enable's natural gas gathering, NGLs and crude oil pipeline facilities are Pipeline and Hazardous Materials Safety Administration jurisdictional. Among other things, these laws and regulations require pipeline operators to develop integrity management programs, including more frequent inspections and other measures, for pipelines located in “high consequence areas.” The regulations require operators, including Enable, to, among other things:

- perform ongoing assessments of pipeline integrity;
- 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.

Failure to comply with the Pipeline and Hazardous Materials Safety Administration or comparable state pipeline safety regulations could result in a number of consequences which may have an adverse effect on Enable's operations. Enable incurs significant costs associated with its compliance with existing Pipeline and Hazardous Materials Safety Administration and comparable state pipeline regulations. Enable incurred maintenance capital expenditures and operation and maintenance expenses of $54.0 million in 2018 and currently estimates that it will incur maintenance capital expenditures and operation and maintenance expenses of up to $65.0 million in 2019 under its pipeline safety program, including costs related to integrity assessments and repairs, threat and risk analyses, implementing preventative and mitigative measures, and conducting activities to support the maximum allowable operating pressure for gas pipelines or the maximum operating pressure for hazardous liquid pipelines. Enable may incur significant cost associated with repair, remediation, preventive and mitigation measures associated with its integrity management programs for pipelines that are not currently subject to regulation by the Pipeline and Hazardous Materials Safety Administration.

Changes to pipeline safety regulations occur frequently. For example, the Pipeline and Hazardous Materials Safety Administration is expected to publish finalized regulations in 2019, for both gas and hazardous liquids pipelines, that will significantly extend and expand the reach of certain Pipeline and Hazardous Materials Safety Administration integrity management requirements (i.e., period assessments, leak detection and repairs) regardless of proximity to a high consequence area. The final rules will also impose new requirements for certain unregulated pipelines, including gathering lines. The adoption of new regulations requiring more comprehensive or stringent safety standards could require Enable to install new or modified safety controls, pursue new capital projects or conduct maintenance programs on an accelerated basis, all of which could require Enable to incur increased and potentially significant operational costs.

Financial reform regulations under the Dodd-Frank Act 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 federal government regulates the derivatives markets and entities, including businesses like Enable, that participate in those market through the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which requires the Commodity Futures Trading Commission and the Securities and Exchange Commission to promulgate rules and regulations implementing the legislation. Under the Commodity Futures Trading Commission's regulations, Enable is subject to reporting and recordkeeping obligations for transactions involving non-financial swap transactions the Commodity Futures Trading Commissions initially 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. In December 2013, the Commodity Futures Trading Commission published a notice of proposed rulemaking designed to implement new position limits regulation and in December 2016, the Commodity Futures Trading Commission's re-proposed regulations for position limits. The ultimate form and timing of the implementation of the regulatory regime affecting commodity derivatives remains uncertain.

The Commodity Futures Trading Commission has imposed mandatory clearing requirements on certain categories of swaps, including certain interest rate swaps, but has exempted derivatives intended to hedge or mitigate commercial risk from the mandatory swap clearing requirement, where a counterparty such as Enable has required identification number, is not a financial entity as defined by the regulations, and meets a minimum asset test. Enable's management believes its hedging transactions qualify for this "commercial end-user" exception. 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 Enable's 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 financial position, results of operations and its ability to make cash distributions to unitholders, including us.

Any reductions in Enable's credit ratings could increase its financing costs and the cost of maintaining certain contractual relationships.

Enable cannot provide assurance that its credit ratings 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 warrant. If any of Enable's credit ratings are below investment grade, it may have higher future borrowing costs and it or its subsidiaries may be required to post cash collateral or letters of credit under certain contractual agreements. If cash collateral requirements were to occur at a time when Enable was experiencing significant working capital requirements or otherwise lacked liquidity, its financial position, results of operations and ability to make cash distributions to unitholders, including us, could be adversely affected.

Enable's Series A Preferred Units have rights, preferences and privileges that are not held by, and are preferential to the rights of, holders of its common units.

Enable's 10 percent Series A Fixed-to-Floating Non-Cumulative Redeemable Perpetual Preferred Units representing limited partner interests in Enable, issued in February 2016, rank senior to all of its other classes or series of equity securities with respect to distribution rights and rights upon liquidation. Enable cannot declare or pay a distribution to its common unitholders for any quarter unless full distributions have been or contemporaneously are being paid on all outstanding Series A Preferred Units for such quarter. These preferences could adversely affect the cash distributions we receive from Enable or could make it more difficult for Enable to sell its common units in the future.

Holders of the Series A Preferred Units will receive, on a non-cumulative basis and if and when declared by Enable's general partner, a quarterly cash distribution, subject to certain adjustments, equal to an annual rate of 10 percent on the stated liquidation preference from the date of original issue to, but not including, the five year anniversary of the original issue date, and an annual rate of the London Interbank Offered Rate plus a spread of 850 basis points on the stated liquidation preference thereafter. In connection with certain transfers of the Series A Preferred Units, the Series A Preferred Units will automatically convert into one or more new series of preferred units (the "other preferred units") on the later of the date of transfer or the second anniversary of the date of issue. The other preferred units will have the same terms as Enable's Series A Preferred Units except that unpaid distributions on the other preferred units will accrue from the date of their issuance on a cumulative basis until paid. Enable's Series A Preferred Units are convertible into common units by the holders of such units in certain circumstances. Payment of distributions on Enable's Series A Preferred Units, or on the common units issued following the conversion of such Series A Preferred Units, could impact its liquidity and reduce the amount of cash flow available for working capital, capital expenditures, growth opportunities, acquisitions, and other general partnership purposes. Enable's obligations to the holders of Series A Preferred Units could also limit its ability to obtain additional financing or increase its borrowing costs, which could have an adverse effect on its financial condition.

Enable's Series A Preferred Units contain covenants that may limit its business flexibility.

Enable's Series A Preferred Units contain covenants preventing it from taking certain actions without the approval of the holders of 66 2/3 percent of the Series A Preferred Units. The need to obtain the approval of holders of the Series A Preferred Units before taking these actions could impede Enable's ability to take certain actions that its management or its board of directors may consider to be in the best interests of its unitholders. The affirmative vote of 66 2/3 percent of the outstanding Series A Preferred Units, voting as a single class, is necessary to amend Enable's Partnership Agreement in any manner that would or could reasonably be expected to have a material adverse effect on the rights, preferences, obligations or privileges of the Series A Preferred Units. The affirmative vote of 66 2/3 percent of the outstanding Series A Preferred Units and any outstanding series of other preferred units, voting as a single class, is necessary to (A) create or issue certain party securities with proceeds in an aggregate amount in excess of $700.0 million or create or issue any senior securities or (B) subject to Enable's right to redeem the Series A Preferred Units, approve certain fundamental transactions.

Enable's Series A Preferred Units are required to be redeemed in certain circumstances if they are not eligible for trading on the New York Stock Exchange, and Enable may not have sufficient funds to redeem its Series A Preferred Units if it is required to do so.

The holders of Enable's Series A Preferred Units may request that Enable list those units for trading on the New York Stock Exchange. If Enable is unable to list the Series A Preferred Units in certain circumstances, it will be required to redeem the Series A Preferred Units. There can be no assurance that Enable would have sufficient financial resources available to satisfy its obligation to redeem the Series A Preferred Units. In addition, mandatory redemption of Enable's Series A Preferred Units could adversely affect its financial position, results of operations and ability to make quarterly cash distributions to its unitholders, including us.

Enable may issue additional units without the approval of its unitholders, which would dilute unitholders' existing ownership interests.

Enable's partnership agreement does not limit the number of additional limited partner interests, including limited partner interests that rank senior to the common units, that it may issue at any time without the approval of its unitholders. The issuance by Enable of additional common units or other equity securities of equal or senior rank will have the following effects:

- Enable's existing unitholders' proportionate ownership interest in Enable will decrease;
- the amount of distributable cash flow on each unit may decrease;
- because the amount payable to holders of incentive distribution rights is based on a percentage of the total distributable cash flow, the distributions to holders of incentive distribution rights will increase even if the per unit distribution on common units remains the same;
- the ratio of taxable income to distributions may increase;
- the relative voting strength of each previously outstanding unit may be diminished; and
- the market price of the common units may decline.

In addition, upon a change of control or certain fundamental transactions, Enable's Series A Preferred Units are convertible into common units at the option of the holders of such units. If a substantial portion of the Series A Preferred Units were converted into common units, common unitholders could experience significant dilution. In addition, if holders of such converted Series A Preferred Units were to dispose of a substantial portion of these common units in the public market, whether in a single transaction or series of transactions, it could adversely affect the market price for Enable's common units. In addition, these sales, or the possibility that these sales may occur, could make it more difficult for Enable to sell its common units in the future.

Affiliates of Enable's general partner may sell common units in the public or private markets, which could have an adverse impact on the trading price of the common units and may sell their interest in its general partner, which may impact its strategic direction.

As of February 1, 2019, CenterPoint held 233,856,623 of Enable's common units and 14,520,000 Series A Preferred Units, and the Company held 110,982,805 of Enable's common units. Enable's Series A Preferred Units are convertible into common units upon a change of control or certain fundamental transactions at the option of the holders of such units. Both Enable's common units held by CenterPoint and the Company, as well as Enable's Series A Preferred Units held by CenterPoint, are subject to certain registration rights. In addition, in the first quarter of 2016, CenterPoint announced that it was evaluating strategic alternatives for its investment in Enable. In the first quarter of 2018, CenterPoint disclosed that it had decided not to pursue a sale or spin-off qualifying under Section 355 of the Code at that time and that, while a transaction for all of its interests in Enable was not viable at that time, it may pursue such a transaction if it becomes viable in the future. CenterPoint also disclosed that it may reduce its investment in Enable through a sale of all or a portion of Enable's common units it owns in the public equity markets or otherwise, subject to certain limitations. While there can be no assurances that these evaluations will result in any specific action, CenterPoint's disclosure, as well as any sales by CenterPoint of the common units it holds in the public or equity markets, could have an adverse impact on the market for Enable's common units, including its ability to issue equity on favorable terms to fund its capital needs or at all. Any sale of Enable's general partner by CenterPoint or the Company may impact Enable's strategic direction, business or results of operations.

Item 1B. Unresolved Staff Comments.

None.

Item 2. Properties.

OG&E owns and operates an interconnected electric generation, transmission and distribution system, located in Oklahoma and western Arkansas, which included 11 generating stations with an aggregate capability of 6,616 MWs at December 31, 2018. 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	2018 Capacity Factor (A)	Unit Capability (MW)	Station Capability (MW)
Seminole	1	1971	Steam-Turbine	Gas	9.9%	426	
	2	1973	Steam-Turbine	Gas	4.9%	425	
	3	1975	Steam-Turbine	Gas/Oil	15.9%	464	1,315
Muskogee	4	1977	Steam-Turbine	Coal	16.5%	479	
	5	1978	Steam-Turbine	Coal	29.2%	501	
	6	1984	Steam-Turbine	Coal	38.0%	503	1,483
Sooner	1	1979	Steam-Turbine	Coal	51.2%	520	
	2	1980	Steam-Turbine	Coal	44.5%	521	1,041
Horseshoe Lake	6	1958	Steam-Turbine	Gas/Oil	13.2%	163	
	7	1963	Combined Cycle	Gas/Oil	12.4%	211	
	8	1969	Steam-Turbine	Gas	5.3%	403	
	9	2000	Combustion-Turbine	Gas	17.6%	43	
	10	2000	Combustion-Turbine	Gas	16.2%	42	862
Redbud (B)	1	2003	Combined Cycle	Gas	51.2%	154	
	2	2003	Combined Cycle	Gas	51.9%	154	
	3	2003	Combined Cycle	Gas	47.9%	153	
	4	2003	Combined Cycle	Gas	49.7%	153	614
Mustang	5A	1971	Combustion-Turbine	Gas/Jet Fuel	0.8%	33	
	5B	1971	Combustion-Turbine	Gas/Jet Fuel	0.8%	31	
	6	2018	Combustion-Turbine	Gas	23.0%	57	
	7	2018	Combustion-Turbine	Gas	25.1%	57	
	8	2017	Combustion-Turbine	Gas	24.8%	58	
	9	2018	Combustion-Turbine	Gas	27.3%	58	
	10	2018	Combustion-Turbine	Gas	26.8%	57	
	11	2018	Combustion-Turbine	Gas	27.0%	57	
	12	2018	Combustion-Turbine	Gas	23.4%	57	465
McClain (C)	1	2001	Combined Cycle	Gas	76.3%	375	375
Total Generating Capability (all stations, excluding renewable)							6,155

Renewable

Station	Year Installed	Location	Number of Units	Fuel Capability	2018 Capacity Factor (A)	Unit Capability (MW)	Station Capability (MW)
Crossroads	2011	Canton, OK	98	Wind	36.9%	2.3	228
Centennial	2007	Laverne, OK	80	Wind	27.9%	1.5	120
OU Spirit	2009	Woodward, OK	44	Wind	33.8%	2.3	101
Mustang	2015	Oklahoma City, OK	90	Solar	20.1%	—	2
Covington	2018	Covington, OK	4	Solar	25.3%	2.4	10
Total Generating Capability (renewable)							461

(A) 2018 Capacity Factor = 2018 Net Actual Generation / (2018 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.

At December 31, 2018, OG&E's transmission system included: (i) 52 substations with a total capacity of 13.2 million kV-amps and 5,100 structure miles of lines in Oklahoma and (ii) seven substations with a total capacity of 2.9 million kV-amps and 277 structure miles of lines in Arkansas. OG&E's distribution system included: (i) 345 substations with a total capacity of 10.2 million kV-amps, 29,345 structure miles of overhead lines, 2,940 miles of underground conduit and 10,932 miles of underground conductors in Oklahoma and (ii) 30 substations with a total capacity of 1.0 million kV-amps, 2,786 structure miles of overhead lines, 297 miles of underground conduit and 685 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, 2018, the Company's gross property, plant and equipment (excluding construction work in progress) additions were $2.0 billion, and gross retirements were $311.2 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 16.6 percent of gross property, plant and equipment (excluding construction work in progress) at December 31, 2018.

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.

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." At December 31, 2018, there were 14,192 holders of record of the Company's common stock.

Issuer Purchases of Equity Securities

None.

Item 6. Selected Financial Data.

HISTORICAL DATA

Year Ended December 31	**2018**	2017	2016	2015	2014
SELECTED FINANCIAL DATA					
(In millions, except per share data)					
Results of Operations Data					
Operating revenues	**$ 2,270.3**	$ 2,261.1	$ 2,259.2	$ 2,196.9	$ 2,453.1
Cost of sales	**892.5**	897.6	880.1	865.0	1,106.6
Operating expenses	**888.2**	831.6	848.3	825.0	788.9
Operating income	**489.6**	531.9	530.8	506.9	557.6
Equity in earnings of unconsolidated affiliates	**152.8**	131.2	101.8	15.5	172.6
Allowance for equity funds used during construction	**23.8**	39.7	14.2	8.3	4.2
Other net periodic benefit expense	**10.8**	21.6	27.5	25.7	20.8
Other income	**21.7**	46.4	26.0	27.0	17.8
Other expense	**23.4**	14.1	16.9	14.3	14.4
Interest expense	**156.0**	143.8	142.1	149.0	148.4
Income tax expense (benefit)	**72.2**	(49.3)	148.1	97.4	172.8
Net income	**$ 425.5**	$ 619.0	$ 338.2	$ 271.3	$ 395.8
Basic earnings per average common share	**$ 2.13**	$ 3.10	$ 1.69	$ 1.36	$ 1.99
Diluted earnings per average common share	**$ 2.12**	$ 3.10	$ 1.69	$ 1.36	$ 1.98
Dividends declared per common share	**$ 1.39500**	$ 1.27000	$ 1.15500	$ 1.05000	$ 0.95000
Balance Sheet Data (at period end)					
Property, plant and equipment, net	**$ 8,643.8**	$ 8,339.9	$ 7,696.2	$ 7,322.4	$ 6,979.9
Total assets	**$ 10,748.6**	$ 10,412.7	$ 9,939.6	$ 9,580.6	$ 9,509.9
Long-term debt (including Long-term debt due within one year)	**$ 3,146.9**	$ 2,999.4	$ 2,630.5	$ 2,738.8	$ 2,737.4
Total stockholders' equity	**$ 4,005.1**	$ 3,851.1	$ 3,443.8	$ 3,326.0	$ 3,244.4
Capitalization Ratios (A)					
Stockholders' equity	**56.0%**	56.2%	56.7%	54.7%	54.1%
Long-term debt	**44.0%**	43.8%	43.3%	45.3%	45.9%

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

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations.

Introduction

The Company is a holding company with investments in energy and energy services providers offering physical delivery and related services for both electricity and natural gas primarily in the south central U.S. 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 it lacks the power to direct activities that most significantly impact economic performance.

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 represents the Company's investment in Enable through wholly owned subsidiaries and ultimately OGE Holdings. Enable was formed in 2013, and its general partner is equally controlled by the Company and CenterPoint, who each have 50 percent management ownership. Based on the 50/50 management ownership, with neither company having control, the Company accounts for its interest in Enable using the equity method of accounting. Enable is primarily 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 Anadarko and Williston Basins. Enable has intrastate natural gas transportation and storage assets that are located in Oklahoma as well as interstate assets that extend from western Oklahoma and the Texas Panhandle to Louisiana, from Louisiana to Illinois and from Louisiana to Alabama. At December 31, 2018, the Company owned 111.0 million common units, or 25.6 percent, of Enable's outstanding units. For additional information on the Company's equity investment in Enable and related party transactions, see Note 4 in "Item 8. Financial Statements and Supplementary Data."

Enable's business is impacted by commodity prices which have declined and otherwise experienced significant volatility in recent years. Commodity prices impact the drilling and production of natural gas and crude oil in the areas served by Enable's systems, and the volumes on Enable's systems are negatively impacted if producers decrease drilling and production in those areas served. Both Enable's gathering and processing segment and Enable's transportation and storage segment can be impacted by drilling and production. Enable's gathering and processing segment primarily serve producers, and many producers utilize the services provided by Enable's transportation and storage segment. A decrease in volumes will decrease the cash flows from Enable's systems. A portion of our earnings and operating cash flows depend on the performance of, and distributions from, Enable. As disclosed in this Form 10-K, Enable is subject to a number of risks, including contract renewal risk, the reliance on the drilling and production decisions of others and the volatility of natural gas, NGLs and crude oil prices. If any of those risks were to occur, the Company's business, financial condition, results of operations or cash flows could be materially adversely affected.

On February 8, 2019, Enable announced a quarterly dividend distribution of $0.31800 per unit on its outstanding common units, which is unchanged from the previous quarter. 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. The Company is entitled to 60 percent of those "incentive distributions."

OG&E participates in the SPP Integrated Marketplace. As part of the Integrated Marketplace, the SPP has 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 to determine which generating units will run at any given time for maximum cost-effectiveness within the SPP area. 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 the Company's 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 customer's 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, with a particular focus 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;
- having 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;
- ensuring we have the necessary mix of generation resources to meet the long-term needs of our customers; and
- 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 four to six 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 Company also utilizes cash distributions from its investment in Enable to help 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 having strong regulatory and legislative relationships.

Summary of Operating Results

2018 compared to 2017. Net income was $425.5 million, or $2.12 per diluted share, in 2018 as compared to $619.0 million, or $3.10 per diluted share, in 2017. The decrease in net income of $193.5 million, or 31.3 percent, or $0.98 per diluted share, in 2018 as compared to 2017 is further discussed below.

- A decrease in net income at OGE Holdings of $216.4 million, or $1.08 per diluted share of the Company's common stock, was primarily due to lower income tax benefit due to an adjustment in 2017 resulting from the 2017 Tax Act, partially offset by higher equity in earnings of Enable due to increased revenues from Enable's gathering and processing business driven by higher processed volumes and higher natural gas gathering fees and gathered volumes.
- An increase in net income at OG&E of $22.5 million, or $0.11 per diluted share of the Company's common stock, was primarily due to higher gross margin due to favorable weather (reduced by lower customer rates which were offset by lower income tax expense). This increase was partially offset by higher depreciation and amortization expense, primarily due to a reduction in depreciation expense recorded in March 2017 for the period from July 1, 2016 to December 31, 2016 resulting from the March 2017 OCC rate order, and higher interest expense driven by increased debt outstanding during 2018 and decreased allowance for borrowed funds used during construction as environmental and large capital projects have been completed.
- A decrease in net loss of other operations of $0.4 million, or $0.01 per diluted share of the Company's common stock, was primarily due to lower other operation and maintenance expense and higher income tax benefit.

2017 compared to 2016. Net income was $619.0 million, or $3.10 per diluted share, in 2017 as compared to $338.2 million, or $1.69 per diluted share, in 2016. The increase in net income of $280.8 million, or 83.0 percent, or $1.41 per diluted share, in 2017 as compared to 2016 is further discussed below.

- The increase in net income at OGE Holdings of $271.5 million, or $1.36 per diluted share of the Company's common stock, was primarily due to an income tax benefit of $245.2 million as a result of the 2017 Tax Act and an increase of equity in earnings of Enable due to increased revenues from Enable's gathering and processing business driven by higher average natural gas prices and higher gathering volumes as well as higher average NGLs prices and higher processed volumes.
- The increase in net income at OG&E of $21.4 million, or $0.11 per diluted share of the Company's common stock, was primarily due to higher net other income driven by increased allowance for equity funds used during construction as environmental and large capital projects were in progress during the year and lower depreciation and amortization expense as a result of the March 2017 OCC rate order mandating a reduction in depreciation rates. These increases were partially offset by higher income tax expense, higher operation and maintenance expense as a result of increased spending on vegetation management and lower gross margin primarily due to milder weather.
- The increase in net loss of other operations of $12.1 million, or $0.06 per diluted share of the Company's common stock, was primarily due to income tax expense of $10.5 million as a result of the 2017 Tax Act.

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.

Recent Developments and Regulatory Matters

As a result of the 2017 Tax Act, in early January 2018: (i) the OCC ordered OG&E to record a reserve, including accrued interest, to reflect the reduced federal corporate tax rate, among other tax implications, on an interim basis, subject to refund until utility rates were adjusted to reflect the federal tax savings; (ii) the APSC ordered OG&E to book regulatory liabilities to record the current and deferred impacts of the 2017 Tax Act until the resulting benefits, including carrying charges, are returned to customers; and (iii) through a Section 206 filing with the FERC, modifications were requested to be made to OG&E's transmission formula rates to reflect the impacts of the 2017 Tax Act.

For Oklahoma jurisdictional revenues, OG&E reserved the excess income taxes collected in current rates, plus interest, from January 2018 through June 2018, and any amortization of excess accumulated deferred income taxes associated with the 2017 Tax Act, which was refunded to Oklahoma customers, as approved by the OCC, during the July 2018 billing cycle. For Arkansas jurisdictional revenues, OG&E reserved the excess income taxes collected in current rates, plus carrying charges, from January 2018 through September 2018, as the Tax Adjustment Rider became effective on October 1, 2018. For FERC jurisdictional revenues, based on an order received from the FERC, OG&E reserved the excess income taxes collected in current rates from January 2018 through June 2018, as the new tax rate was reflected in billings beginning with the July 2018 invoice. Further, for Arkansas and FERC jurisdictional revenues, OG&E is also reserving any amortization of excess accumulated deferred income taxes associated with the 2017 Tax Act.

In January 2018, OG&E filed a general rate review in Oklahoma, seeking recovery of the seven combustion turbines that were part of the Mustang Modernization Plan, requesting an increase in depreciation rates to levels similar with rates in existence prior to the March 2017 OCC rate order and crediting customers for the impacts of the 2017 Tax Act. In June 2018, the OCC approved a Joint Stipulation and Settlement Agreement. As a result of the settlement, new rates were implemented on July 1, 2018.

In December 2018, OG&E filed a general rate review with the OCC, requesting a rate increase to recover its investments in the Dry Scrubbers project and in the conversion of Muskogee Units 4 and 5 to natural gas to comply with the Regional Haze Rule. The filing also seeks to align OG&E's return on equity more closely to the industry average and to align OG&E's depreciation rates to more realistically reflect its assets' lifespans.

In December 2018, OG&E filed an application for pre-approval from the OCC to acquire a coal- and natural gas-fired plant from AES and a natural gas-fired combined-cycle plant from Oklahoma Cogeneration LLC in 2019. The purchase of these assets is intended to replace capacity currently provided by power purchase contracts set to expire in 2019 and to help OG&E satisfy its customers' energy needs and load obligations to the SPP.

Further discussion can be found in Note 15 within "Item 8. Financial Statements and Supplementary Data."

2019 Outlook

Key assumptions for 2019 include:

OG&E

The Company projects OG&E to earn approximately $311 million to $325 million, or $1.55 to $1.62 per average diluted share, in 2019 and is based on the following assumptions:

- normal weather patterns are experienced for the remainder of the year;
- gross margin on revenues of approximately $1.416 billion to $1.421 billion based on sales growth of approximately one percent on a weather-adjusted basis;
- operating expenses of approximately $941 million to $949 million, with operation and maintenance expenses comprising approximately 50 percent of the total;
- interest expense of approximately $143 million to $145 million which assumes a $1.4 million allowance for borrowed funds used during construction reduction to interest expense and assumes a debt issuance of $300 million in the second half of 2019;
- other income of approximately $3.5 million including approximately $3.3 million of allowance for equity funds used during construction;
- an effective tax rate of approximately 4.4 percent;
- new rates take effect in Oklahoma by July 1, 2019; and
- every 25 basis point change in the allowed Oklahoma return on equity equates to a change of approximately $9.4 million in revenue.

OG&E has significant seasonality in its earnings. OG&E typically shows the majority of its earnings in the second and third quarters due to the seasonal nature of air conditioning demand.

OGE Holdings

The Company projects the earnings contribution from its ownership interest in Enable for 2019 to be approximately $104 million to $117 million, or $0.52 to $0.58 per average diluted share, and receive approximately $140 million in cash distributions.

Consolidated OGE

The Company's 2019 earnings guidance is between approximately $412 million and $442 million of net income, or $2.05 to $2.20 per average diluted share, and is based on the following assumptions:

- approximately 201 million average diluted shares outstanding;
- an effective tax rate of approximately 9.9 percent; and
- a $0.00 to ($0.02) or up to $4 million loss at OGE Energy due to interest expense.

OG&E's Non-GAAP Financial Measures

Gross margin is defined by OG&E as operating revenues less cost of sales. Cost of sales, as reflected on the income statement, includes 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. Further, gross margin is not intended to replace operating revenues as determined in accordance with GAAP as an indicator of operating performance. For a reconciliation of gross margin to revenue, which is the most directly comparable financial measure calculated and presented in accordance with GAAP, for the years ended December 31, 2018, 2017 and 2016, see "OG&E (Electric Utility) Results of Operations" below.

Detailed below is a reconciliation of gross margin to revenue included in the 2019 Outlook.

(In millions)		Twelve Months Ended December 31, 2019 (A)
Operating revenues	$	1,820
Cost of sales		402
Gross margin	$	1,418

(A) Based on the midpoint of OG&E earnings guidance for 2019.

Enable's Non-GAAP Financial Measures

Gross margin is defined by Enable as total revenues minus costs of natural gas and NGLs, excluding depreciation and amortization. Total revenues consist of the fees that Enable charges its customers and the sales price of natural gas and NGLs that Enable sells. The cost of natural gas and NGLs consists of the purchase price of natural gas and NGLs that Enable purchases. Enable deducts the cost of natural gas and NGLs from total revenues to arrive at a measure of the core profitability of their mix of fee-based and commodity-based customer arrangements. Gross margin allows for meaningful comparison of the operating results between Enable's fee-based revenues and Enable's commodity-based contracts which involve the purchase or sale of natural gas, NGLs and/or crude oil. In addition, the Company believes gross margin allows for a meaningful comparison of the results of Enable's commodity-based activities across different commodity price environments because it measures the spread between the product sales price and cost of products sold. Enable's definition of gross margin may be different from similar terms used by other companies. Further, gross margin is not intended to replace operating revenues as determined in accordance with GAAP as an indicator of operating performance. For a reconciliation of gross margin to revenue, which is the most directly comparable financial measure calculated and presented with GAAP, for the years ending December 31, 2018, 2017 and 2016, see "OGE Holdings (Natural Gas Midstream Operations) Results of Operations" below.

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, 2018, 2017 and 2016 and the Company's consolidated financial position at December 31, 2018 and 2017. 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)		**2018**		2017		2016
Net income	**$**	**425.5**	$	619.0	$	338.2
Basic average common shares outstanding		**199.7**		199.7		199.7
Diluted average common shares outstanding		**200.5**		200.0		199.9
Basic earnings per average common share	**$**	**2.13**	$	3.10	$	1.69
Diluted earnings per average common share	**$**	**2.12**	$	3.10	$	1.69
Dividends declared per common share	**$**	**1.39500**	$	1.27000	$	1.15500

Results by Business Segment

	Year Ended December 31,					
(In millions)		**2018**		2017		2016
Net income (loss):						
OG&E (Electric Utility)	**$**	**328.0**	$	305.5	$	284.1
OGE Holdings (Natural Gas Midstream Operations) (A)		**108.8**		325.2		53.7
Other operations (B)		**(11.3)**		(11.7)		0.4
Consolidated net income	**$**	**425.5**	$	619.0	$	338.2

(A) The Company recorded an income tax benefit of $245.2 million during the fourth quarter of 2017 due to the Company remeasuring deferred taxes at OGE Holdings, as a result of the 2017 Tax Act. See Note 8 in "Item 8. Financial Statements and Supplementary Data" for further discussion of the effects of the 2017 Tax Act.

(B) Other operations primarily includes the operations of OGE Energy 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)*	**2018**	2017	2016
Operating revenues	**$ 2,270.3**	$ 2,261.1	$ 2,259.2
Cost of sales	**892.5**	897.6	880.1
Other operation and maintenance	**473.8**	469.8	451.2
Depreciation and amortization	**321.6**	280.9	316.4
Taxes other than income	**88.2**	84.8	84.0
Operating income	**494.2**	528.0	527.5
Allowance for equity funds used during construction	**23.8**	39.7	14.2
Other net periodic benefit expense	**8.9**	16.3	18.6
Other income	**14.1**	36.6	16.4
Other expense	**3.4**	2.3	2.9
Interest expense	**151.8**	138.4	138.1
Income tax expense	**40.0**	141.8	114.4
Net income	**$ 328.0**	$ 305.5	$ 284.1
Operating revenues by classification:			
Residential	**$ 901.0**	$ 884.1	$ 951.9
Commercial	**598.0**	588.3	573.7
Industrial	**196.7**	200.6	194.6
Oilfield	**153.2**	159.5	156.9
Public authorities and street light	**204.0**	208.0	204.3
Sales for resale	**0.2**	0.2	0.3
System sales revenues	**2,053.1**	2,040.7	2,081.7
Provision for rate refund	**(6.0)**	26.8	(33.6)
Integrated market	**48.7**	23.5	49.3
Transmission	**147.4**	151.2	143.0
Other	**27.1**	18.9	18.8
Total operating revenues	**$ 2,270.3**	$ 2,261.1	$ 2,259.2
Reconciliation of gross margin to revenue:			
Operating revenues	**$ 2,270.3**	$ 2,261.1	$ 2,259.2
Cost of sales	**892.5**	897.6	880.1
Gross margin	**$ 1,377.8**	$ 1,363.5	$ 1,379.1
MWh sales by classification *(In millions)*			
Residential	**9.7**	8.8	9.3
Commercial	**8.1**	7.6	7.6
Industrial	**3.8**	3.6	3.6
Oilfield	**3.4**	3.2	3.2
Public authorities and street light	**3.1**	3.1	3.2
System sales	**28.1**	26.3	26.9
Integrated market	**1.4**	1.8	3.0
Total sales	**29.5**	28.1	29.9
Number of customers	**849,372**	841,830	833,582
Weighted-average cost of energy per kilowatt-hour *(In cents)*			
Natural gas	**2.517**	2.821	2.488
Coal	**2.025**	2.069	2.213
Total fuel	**2.122**	2.211	2.199
Total fuel and purchased power	**2.900**	3.049	2.842
Degree days (A)			
Heating - Actual	**3,776**	2,877	2,800
Heating - Normal	**3,349**	3,349	3,349
Cooling - Actual	**2,123**	1,944	2,247
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.

2018 compared to 2017. OG&E's net income increased $22.5 million, or 7.4 percent, in 2018 as compared to 2017, primarily due to higher gross margin (reduced by lower customer rates which were offset by lower income tax expense), partially offset by higher depreciation and amortization expense, primarily due to a reduction in depreciation expense recorded in March 2017 for the period from July 1, 2016 to December 31, 2016 resulting from the March 2017 OCC rate order, lower other income and higher interest expense.

Gross margin increased $14.3 million, or 1.0 percent, in 2018 as compared to 2017. The below factors contributed to the change in gross margin.

(In millions)	**$ Change**
Weather (price and quantity) (A)	$ 43.0
New customer growth	7.8
Non-residential demand and related revenue	6.9
Industrial and oilfield sales	5.7
Price variance (B)	(36.4)
Reserve for tax refund (C)	(15.4)
Wholesale transmission revenue (D)	(7.1)
Other	9.8
Change in gross margin	$ 14.3

(A) Cooling and heating degree days increased nine percent and 31 percent, respectively, during the year ended December 31, 2018, as compared to the same periods in 2017.

(B) Decreased during the year ended December 31, 2018 primarily due to new Oklahoma rates being implemented on July 1, 2018 and new rates being implemented for Arkansas customers in October 2018, both of which reflected the lower corporate federal tax rate as a result of the 2017 Tax Act, as well as the Oklahoma and Arkansas tax refunds to customers during the July 2018 and October 2018 billing cycles, respectively, for amounts reserved in previous months during 2018 prior to the implementation of new rates.

(C) Further discussion of OG&E's reserve for tax refund in response to OCC, APSC and FERC proceedings can be found in Notes 8 and 15 in "Item 8. Financial Statements and Supplementary Data."

(D) Beginning with the July 2018 invoice, billings reflected the lower corporate federal tax rate enacted by the 2017 Tax Act, as discussed in Note 15 in "Item 8. Financial Statements and Supplementary Data."

Cost of sales for OG&E consists of fuel used in electric generation, purchased power and transmission-related charges. 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 and the APSC. OG&E's cost of sales decreased $5.1 million, or 0.6 percent, in 2018 as compared to 2017. The below factors contributed to the change in cost of sales.

(In millions)	**$ Change**	**% Change**
Fuel expense (A)	$ (22.3)	(5.5)%
Purchased power costs:		
Purchases from SPP (B)	23.8	10.3 %
Wind	(3.6)	(5.7)%
Cogeneration	(2.8)	(2.4)%
Transmission expense (C)	(0.9)	(1.3)%
Curtailment expense	0.7	9.3 %
Change in cost of sales	$ (5.1)	

(A) Decrease in fuel expense during the year ended 2018 was primarily due to lower fuel prices and decreased utilization of company-owned generation.
(B) Increase in the cost of purchases from the SPP for the year ended 2018 was due to a 21.1 percent increase in MWhs purchased, partially offset by a 9.0 percent decrease in cost per MWhs purchased due to a decrease in fuel prices.
(C) Decrease in transmission-related charges was primarily due to lower SPP charges driven by lower rates charged to OG&E for transmission service as a result of lower tax rates due to the 2017 Tax Act.

Other operation and maintenance expense increased $4.0 million, or 0.9 percent, in 2018 as compared to 2017. The below factors contributed to the change in other operation and maintenance expense.

(In millions)	**$ Change**	**% Change**
Payroll and benefits (A)	$ 13.6	5.8 %
Contract technical and construction services and materials and supplies (B)	(5.9)	(8.2)%
Other	(3.7)	(2.3)%
Change in other operation and maintenance expense	$ 4.0	

(A) Increased primarily due to annual salary increases and an increase in incentive compensation.
(B) Changes are primarily due to the timing of normal plant maintenance.

Depreciation and amortization expense increased $40.7 million, or 14.5 percent, primarily due to a reduction in depreciation expense of approximately $20.0 million recorded in March 2017 for the period from July 1, 2016 to December 31, 2016 resulting from the March 2017 OCC rate order, and additional assets being placed into service.

Allowance for equity funds used during construction decreased $15.9 million, or 40.1 percent, primarily due to lower construction work in progress balances resulting from certain environmental projects being completed and placed into service.

Other net periodic benefit expense decreased $7.4 million, or 45.4 percent, primarily due to amortization of unrecognized prior service cost.

Other income decreased $22.5 million, or 61.5 percent, primarily due to a decrease in the tax gross-up related to lower allowance for funds used during construction and a change in the presentation of guaranteed flat bill margins, which are now included in gross margin due to the adoption of the new revenue recognition standard (ASC 606).

Allowance for borrowed funds used during construction decreased $6.3 million, or 35.0 percent, primarily due to lower construction work in progress balances resulting from certain environmental projects being completed and placed into service.

Income tax expense decreased $101.8 million, or 71.8 percent, primarily due to a reduction in the corporate federal tax rate, an increase in the amortization of net unfunded deferred taxes, an increase in state tax credit generation and lower pre-tax income.

2017 compared to 2016. OG&E's net income increased $21.4 million, or 7.5 percent, in 2017 as compared to 2016, primarily due to lower depreciation and amortization expense as a result of the March 2017 OCC rate order mandating a reduction in depreciation rates, higher allowance for equity funds used during construction, higher other income and higher allowance for borrowed funds used during construction, partially offset by higher income tax expense, higher operation and maintenance expense, lower gross margin and higher interest on long-term debt.

Gross margin decreased $15.6 million, or 1.1 percent, in 2017 as compared to 2016. The below factors contributed to the change in gross margin.

(In millions)	**$ Change**
Weather (price and quantity) (A)	$ (15.1)
Price variance (B)	(13.9)
Wholesale transmission revenue	(8.1)
New customer growth	14.2
Non-residential demand and related revenues	5.0
Industrial and oilfield sales	2.2
Other	0.1
Change in gross margin	$ (15.6)

(A) Cooling degree days decreased approximately 13 percent in 2017.
(B) Decreased primarily due to additional reserves for rate refunds in both Oklahoma and Arkansas, as well as riders moving to base rates in the March 2017 OCC rate order.

OG&E's cost of sales increased $17.5 million, or 2.0 percent, in 2017 as compared to 2016. The below factors contributed to the change in cost of sales.

(In millions)	**$ Change**	**% Change**
Fuel expense (A)	$ (61.5)	(13.1)%
Purchased power costs:		
Purchases from SPP (B)	74.4	47.2 %
Wind	0.2	0.4 %
Cogeneration	(9.5)	(7.6)%
Transmission expense (C)	13.9	23.5 %
Change in cost of sales	$ 17.5	

(A) Decrease in fuel expense was primarily due to decreased utilization of company-owned generation.
(B) Increase in the cost of purchases from the SPP was due to an increase of 26.8 percent in MWh purchased and an increase of 16.2 percent in cost per MWhs purchased. The increase in cost per MWh purchased was due to an increase in fuel prices and higher grid congestion costs during 2017.
(C) Increase in transmission-related charges was primarily due to higher SPP charges for the base plan projects of other utilities.

Other operation and maintenance expense increased $18.6 million, or 4.1 percent, in 2017 as compared to 2016. The below factors contributed to the change in other operation and maintenance expense.

(In millions)	**$ Change**	**% Change**
Vegetation management	$ 14.5	68.7 %
Other	11.5	2.2 %
Capitalized labor (A)	(7.4)	(7.9)%
Change in other operation and maintenance expense	$ 18.6	

(A) Increased during 2017 primarily due to more storm costs exceeding the $2.7 million OCC-allowed threshold, which were moved to a regulatory asset, as well as mutual assistance, which was provided in the aftermath of Hurricanes Harvey and Irma.

Depreciation and amortization expense decreased $35.5 million, or 11.2 percent, primarily due to lower depreciation expense related to the reduction in depreciation rates approved in the March 2017 OCC rate order, partially offset by additional assets being placed into service.

Allowance for equity funds used during construction increased $25.5 million, primarily due to higher construction work in progress balances resulting from increased spending for environmental projects.

Other income increased $20.2 million, primarily due to an increase in the tax gross-up related to higher allowance for funds used during construction and an increase in gains on guaranteed flat bill margins.

Allowance for borrowed funds used during construction increased $10.5 million, primarily due to higher construction work in progress balances resulting from increased spending for environmental projects.

Income tax expense increased $27.4 million, or 24.0 percent, primarily due to higher pre-tax operating income and lower tax credits generated.

OGE Holdings (Natural Gas Midstream Operations)

	Year Ended December 31,		
(In millions)	**2018**	2017	2016
Operating revenues	**$ —**	$ —	$ —
Cost of sales	**—**	—	—
Other operation and maintenance	**1.4**	(0.8)	(0.1)
Depreciation and amortization	**—**	—	—
Taxes other than income	**0.6**	1.0	—
Operating income (loss)	**(2.0)**	(0.2)	0.1
Equity in earnings of unconsolidated affiliates	**152.8**	131.2	101.8
Other expense	**(4.9)**	(1.0)	(7.7)
Income before taxes	**145.9**	130.0	94.2
Income tax expense (benefit) (A)	**37.1**	(195.2)	40.5
Net income attributable to OGE Holdings	**$ 108.8**	$ 325.2	$ 53.7

(A) Includes an income tax benefit of $245.2 million in 2017 due to the remeasurement of deferred taxes, as a result of the 2017 Tax Act.

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, 2018, 2017 and 2016.

	Year Ended December 31,		
(In millions)	**2018**	2017	2016
Enable net income	**$ 485.3**	$ 400.3	$ 289.5
Distributions senior to limited partners	**—**	—	(9.1)
Differences due to timing of OGE Energy and Enable accounting close	**—**	—	(12.2)
Enable net income used to calculate OGE Energy's equity in earnings	**$ 485.3**	$ 400.3	$ 268.2
OGE Energy's percent ownership at period end	**25.6%**	25.7%	25.7%
OGE Energy's portion of Enable net income	**$ 124.4**	$ 102.7	$ 70.7
Impairments recognized by Enable associated with OGE Energy's basis difference	**—**	—	2.6
OGE Energy's share of Enable net income	**124.4**	102.7	73.3
Amortization of basis difference	**11.2**	11.3	11.6
Elimination of Enable fair value step up	**17.2**	17.2	16.9
Equity in earnings of unconsolidated affiliates	**$ 152.8**	$ 131.2	$ 101.8

Equity in earnings of unconsolidated affiliates includes the Company's share of Enable earnings adjusted for the amortization of the basis difference of the Company's investment in Enogex LLC and its underlying equity in the net assets of Enable and 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 $680.3 million as of December 31, 2018. The following table reconciles the basis difference in Enable from December 31, 2017 to December 31, 2018.

(In millions)		
Basis difference at December 31, 2017	$	714.2
Change in Enable basis difference		(5.5)
Amortization of basis difference		(11.2)
Elimination of Enable fair value step up		(17.2)
Basis difference at December 31, 2018	$	680.3

Enable Results of Operations

The following tables represents summarized financial information of Enable for 2018, 2017 and 2016:

	Year Ended December 31,					
(In millions)		**2018**		2017		2016
Reconciliation of gross margin to revenue:						
Total revenues	**$**	**3,431**	$	2,803	$	2,272
Cost of natural gas and NGLs		**1,819**		1,381		1,017
Gross margin	**$**	**1,612**	$	1,422	$	1,255
Operating income	**$**	**648**	$	528	$	385
Net income	**$**	**485**	$	400	$	290

	Year Ended December 31,		
	2018	2017	2016
Natural gas gathered volumes - TBtu/d	**4.48**	3.56	3.13
Transported volumes - TBtu/d	**5.56**	5.04	4.88
Natural gas processed volumes - TBtu/d	**2.40**	1.96	1.80
NGL sold - MBbl/d (A)(B)	**132.06**	92.21	78.16
Crude oil and condensate gathered volumes - MBbl/d	**41.07**	25.56	25.00

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

Year Ended December 31, 2018 as compared to Year Ended December 31, 2017

OGE Holdings' earnings before taxes increased $15.9 million for the year ended December 31, 2018 as compared to the same period in 2017, primarily due to an increase in equity in earnings of Enable of $21.6 million, partially offset by an increase in other expense and an increase in operation and maintenance expense. The following table presents summarized information regarding Enable's income statement changes for the year ended December 31, 2018, compared to the same period in 2017, and the corresponding impact those changes had on the Company's equity in earnings of Enable.

The increase in the Company's equity in earnings of Enable was primarily due to the following:

(In millions)		**Income Statement Change at Enable**		**Impact to Company's Equity in Earnings**
Gross margin	$	190.0	$	48.7
Operation and maintenance, General and administrative	$	37.0	$	(9.5)
Depreciation and amortization	$	32.0	$	(8.2)
Interest expense	$	32.0	$	(8.2)

Enable's gathering and processing business segment reported an increase in operating income of $137.0 million. The following table presents summarized information regarding Enable's gathering and processing business segment income statement changes for the year ended December 31, 2018, compared to the same period in 2017, and the corresponding impact those changes had on the Company's equity in earnings of Enable.

The increase in Enable's gathering and processing business segment operating income was primarily due to the following:

(In millions)	**Income Statement Change at Enable**	**Impact to Company's Equity in Earnings**
Gross margin	$ 192.0	$ 49.2
Operation and maintenance, General and administrative	$ 23.0	$ (5.9)
Depreciation and amortization	$ 31.0	$ (7.9)

Gathering and processing gross margin increased primarily due to the following:

- an increase in processing service fees resulting from higher processed volumes primarily under fixed processing arrangements in the Anadarko and Ark-La-Tex Basins;
- an increase in natural gas gathering fees due to higher fees and gathered volumes in the Anadarko and Ark-La-Tex Basins;
- an increase in changes in the fair value of natural gas, condensate and NGLs derivatives;
- an increase in revenues from NGLs sales less the cost of NGLs, partially offset by higher average NGLs prices and higher processed volumes in the Anadarko and Ark-La-Tex Basins; and
- an increase in crude oil, condensate and produced water gathering revenues driven by an increase in the Anadarko Basin due to the acquisition of Velocity Holdings, LLC in the fourth quarter of 2018 and an increase in the Williston Basin due to higher gathered volumes, partially offset by a reduction in average rates; partially offset by
- a decrease in revenues from natural gas sales less the cost of natural gas primarily due to a decrease due to lower average prices partially offset by higher sales volumes and an increase in fuel costs; and
- a decrease due to intercompany management fees.

Enable's transportation and storage business segment reported a decrease in operating income of $19.0 million. The following table presents summarized information regarding Enable's transportation and storage business segment income statement changes for the year ended December 31, 2018, compared to the same period in 2017, and the corresponding impact those changes had on the Company's equity in earnings of Enable.

The decrease in transportation and storage business segment operating income was primarily due to the following:

(In millions)	**Income Statement Change at Enable**	**Impact to Company's Equity in Earnings**
Gross margin	$ (8.0)	$ (2.0)
Operation and maintenance, General and administrative	$ 10.0	$ (2.6)

Transportation and storage gross margin decreased primarily due to the following:

- a decrease in changes in the fair value of natural gas derivatives; and
- a decrease in firm transportation services between Carthage, Texas and Perryville, Louisiana due to contract expirations during 2017; partially offset by
- an increase in other firm transportation and storage services due to new interstate and intrastate transportation contracts;
- an increase in volume-dependent transportation primarily due to an increase in commodity fees from new contracts and an increase in off-system transportation due to increases in volumes at higher rates; and
- an increase in system management activities.

Income tax expense was $37.1 million during the year ended December 31, 2018 as compared to income tax benefit of $195.2 million during the same period in 2017. The change is primarily due to the remeasurement of federal deferred taxes in 2017 as a result of the 2017 Tax Act.

Year Ended December 31, 2017 as compared to Year Ended December 31, 2016

OGE Holdings' earnings before taxes increased $35.8 million for the year ended December 31, 2017 as compared to the same period of 2016, primarily due to an increase in equity in earnings of Enable of $29.4 million and a decrease in pension settlement expense of $6.8 million. The following table presents summarized information regarding Enable's income statement changes for the year ended December 31, 2017, compared to the same period in 2016, and the corresponding impact those changes had on the Company's equity in earnings of Enable.

The increase in the Company's equity in earnings of Enable was primarily due to the following:

(In millions)	**Income Statement Change at Enable**	**Impact to Company's Equity in Earnings**
Gross margin	$ 167.0	$ 42.9
Impairments	$ (9.0)	$ 2.3
Depreciation and amortization	$ 28.0	$ (7.2)
Interest expense	$ 21.0	$ (5.4)
Preferred distributions	$ 14.0	$ (3.6)

Enable's gathering and processing business segment reported an increase in operating income of $131.0 million. The following table presents summarized information regarding Enable's gathering and processing business segment income statement changes for the year ended December 31, 2017, compared to the same period in 2016, and the corresponding impact those changes had on the Company's equity in earnings of Enable.

The increase in Enable's gathering and processing business segment operating income was primarily due to the following:

(In millions)	**Income Statement Change at Enable**	**Impact to Company's Equity in Earnings**
Gross margin	$ 160.0	$ 41.1
Depreciation and amortization	$ 20.0	$ (5.1)
Operation and maintenance, General and administrative	$ 13.0	$ (3.3)

Gathering and processing gross margin increased primarily due to an increase in gross margin from natural gas sales due to higher average natural gas prices and higher gathering volumes in the Anadarko and Ark-La-Tex Basins, an increase in processing margins resulting from higher average NGL prices and higher processed volumes in the Anadarko Basin, an increase in gathering margin due to increased gathering volumes in the Anadarko and Ark-La-Tex Basins and increased billings under minimum volume commitments in the Arkoma Basin and an increase in gross margin from changes in the fair value of condensate and NGL derivatives.

Enable's transportation and storage business segment reported an increase in operating income of $13.0 million. The following table presents summarized information regarding Enable's transportation and storage business segment income statement changes for the year ended December 31, 2017, compared to the same period in 2016, and the corresponding impact those changes had on the Company's equity in earnings of Enable.

The increase in transportation and storage business segment operating income was primarily due to the following:

(In millions)	**Income Statement Change at Enable**	**Impact to Company's Equity in Earnings**
Operation and maintenance, General and administrative	$ (12.0)	$ 3.1
Gross margin	$ 10.0	$ 2.6
Depreciation and amortization	$ 8.0	$ (2.1)

Transportation and storage gross margin increased primarily due to an increase in gross margin from changes in the fair value of natural gas derivatives, an increase in NGL sales due to an increase in transported volumes and NGL prices and an increase in off-system transportation margins. These increases were partially offset by a decrease in system management activities, a decrease in firm transportation services between Carthage, Texas and Perryville, Louisiana and a decrease in realized gains on natural gas derivatives.

Income tax benefit was $195.2 million during the year ended December 31, 2017 as compared to income tax expense of $40.5 million during the same period in 2016. The change is primarily due to a remeasurement of federal deferred taxes related to the 2017 Tax Act, a remeasurement of state deferred taxes and return to provision adjustments related to the Company's investment in Enable during the year ended December 31, 2016, offset by higher pre-tax operating income.

Off-Balance Sheet Arrangement

OG&E Railcar Lease Agreement

As of December 31, 2018, OG&E has a noncancellable operating lease with a purchase option, covering 1,093 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.

At the end of the lease term, which was February 1, 2019, OG&E had the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chose not to purchase the railcars or renew the lease agreement and the actual fair value of the railcars was less than the stipulated fair market value, OG&E would have been responsible for the difference in those values up to a maximum of $16.2 million. OG&E was also required to maintain all of the railcars it had under the operating lease.

On February 1, 2019, OG&E renewed the lease agreement effective February 1, 2019, under similar terms and conditions, for a fleet of 780 railcars, expiring February 1, 2024. The number of railcars was reduced due to the conversion of Muskogee Units 4 and 5 to natural gas. At the end of the lease term, 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 $6.8 million.

The railcar lease was recorded on the Company's 2019 Balance Sheet upon adoption of the new leases standard (ASC 842).

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 in Cash and Cash Equivalents was $94.3 million and $14.4 million at December 31, 2018 and 2017, respectively, an increase of $79.9 million, primarily due to normal business operations and quarterly distributions received from Enable, which the Company elected to apply towards payment of the $250.0 million senior notes due on January 15, 2019.

Accounts Receivable and Accrued Unbilled Revenues. The balance of Accounts Receivable and Accrued Unbilled Revenues was $237.3 million and $257.1 million at December 31, 2018 and 2017, respectively, a decrease of $19.8 million, or 7.7 percent, primarily due to a decrease in billings to OG&E's retail customers.

Fuel Inventories. The balance in Fuel Inventories was $57.6 million and $84.3 million at December 31, 2018 and 2017, respectively, a decrease of $26.7 million, or 31.7 percent, primarily due to decreased coal and gas inventory.

Materials and Supplies, at Average Cost. The balance of Materials and Supplies, at Average Cost was $126.7 million and $80.8 million at December 31, 2018 and 2017, respectively, an increase of $45.9 million, or 56.8 percent, primarily due to increased inventory related to long-term service agreements.

Other Current Assets. The balance of Other Current Assets was $29.5 million and $54.6 million at December 31, 2018 and 2017, respectively, a decrease of $25.1 million, or 46.0 percent, primarily due to increased collections from customers associated with various rate riders.

Short-Term Debt. There was no balance of Short-term Debt at December 31, 2018 compared to a balance of $168.4 million at December 31, 2017, respectively, a decrease of $168.4 million. The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreements. The decrease was primarily due to the proceeds of the senior notes issuance in August 2018 being utilized for general corporate purposes instead of borrowing under the Company's revolving credit agreement.

Accounts Payable. The balance of Accounts Payable was $239.3 million and $230.4 million at December 31, 2018 and 2017, respectively, an increase of $8.9 million, or 3.9 percent, primarily due to the timing of vendor payments.

Accrued Compensation. The balance of Accrued Compensation was $47.8 million and $35.9 million at December 31, 2018 and 2017, respectively, an increase of $11.9 million, or 33.1 percent, primarily due to higher accruals for incentive compensation, partially offset by a lower amount of accrued vacation.

Other Current Liabilities. The balance of Other Current Liabilities was $87.0 million and $28.7 million at December 31, 2018 and 2017, respectively, an increase of $58.3 million, primarily due to amounts owed to customers, including the reserve for tax refund of $15.4 million resulting from the 2017 Tax Act, SPP reserves of $29.9 million and over recovery of the SPP cost tracker of $16.8 million.

Cash Flows

				2018 vs. 2017		2017 vs. 2016	
Year Ended December 31 *(In millions)*	**2018**	2017	2016	**$ Change**	**% Change**	$ Change	% Change
Net cash provided from operating activities	**$ 951.1**	$ 784.5	$ 644.7	**$ 166.6**	**21.2 %**	$ 139.8	21.7%
Net cash used in investing activities	**$ (576.0)**	$ (821.9)	$ (620.4)	**$ 245.9**	**(29.9)%**	$ (201.5)	32.5%
Net cash (used in) provided from financing activities	**$ (295.2)**	$ 51.5	$ (99.2)	**$ (346.7)**	*****	$ 150.7	*

* Greater than a 100 percent variance.

Operating Activities

The increase of $166.6 million, or 21.2 percent, in net cash provided from operating activities in 2018 as compared to 2017 was primarily due to a decrease in vendor payments and an increase in amounts received from customers at OG&E.

The increase of $139.8 million, or 21.7 percent, in net cash provided from operating activities in 2017 as compared to 2016 was primarily due to increased amounts received from customers, primarily due to recovery of fuel costs, partially offset by an increase in vendor payments.

Investing Activities

The decrease of $245.9 million, or 29.9 percent, in net cash used in investing activities in 2018 as compared to 2017 was primarily due to a decrease in capital expenditures primarily related to environmental and large capital projects at OG&E.

The increase of $201.5 million, or 32.5 percent, in net cash used in investing activities in 2017 as compared to 2016 was primarily due to an increase in capital expenditures related to multiple environmental and large capital projects at OG&E.

Financing Activities

The increase of $346.7 million in net cash used in financing activities in 2018 as compared to 2017 was primarily due to the issuance of less long-term debt by OG&E in 2018, a decrease in short-term debt and additional long-term debt paid off in 2018.

The increase of $150.7 million in net cash provided from financing activities in 2017 as compared to 2016 was primarily due to the issuance by OG&E of $300.0 million in long-term debt in each of March 2017 and August 2017, partially offset by a decrease in short-term debt and the payment of $100.0 million in long-term debt in November 2017.

2018 Capital Requirements, Sources of Financing and Financing Activities

Total capital requirements, consisting of capital expenditures and maturities of long-term debt, were $823.7 million, and contractual obligations, net of recoveries through fuel adjustment clauses, were $76.4 million, resulting in total net capital requirements and contractual obligations of $900.1 million in 2018, of which $139.8 million was to comply with environmental regulations. This compares to net capital requirements of $1,049.2 million and net contractual obligations of $78.8 million totaling $1,128.0 million in 2017, of which $213.9 million was to comply with environmental regulations.

In 2018, the Company's primary sources of capital were cash generated from operations, proceeds from the issuance of long- and short-term debt 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 have been used at times in managing OG&E's commodity price exposure. The Dodd-Frank Act, among other things, provides for regulation by the Commodity Futures Trading Commission of certain commodity-related contracts. Although OG&E qualifies for an end-user exception from mandatory clearing of commodity-related swaps, these regulations could affect the ability of OG&E to participate in these markets and could add additional regulatory oversight over its contracting activities.

Future 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.

Capital Expenditures

The Company's consolidated estimates of capital expenditures for the years 2019 through 2023 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)	2019	2020	2021	2022	2023
Transmission	$ 40	$ 35	$ 35	$ 35	$ 35
Distribution:					
Oklahoma	195	205	225	225	225
Arkansas	55	30	15	15	15
Generation	145	75	60	60	90
Other	50	40	40	40	30
Total transmission, distribution, generation and other	485	385	375	375	395
Projects:					
Environmental - Dry Scrubbers (A)	15	—	—	—	—
Environmental - natural gas conversion (A)	10	—	—	—	—
Grid modernization, reliability, resiliency, technology and other	115	190	225	210	185
Total projects	140	190	225	210	185
Total	$ 625	$ 575	$ 600	$ 585	$ 580

(A) Represent capital costs associated with OG&E's ECP to comply with the EPA's Regional Haze Rule. More detailed discussion regarding the Regional Haze Rule and OG&E's ECP can be found in Notes 14 and 15 in "Item 8. Financial Statements and Supplementary Data" and in "Environmental Laws and Regulations" below.

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

Contractual Obligations

The following table summarizes the Company's contractual obligations at December 31, 2018. See the Company's Consolidated Statements of Capitalization and Note 14 in "Item 8. Financial Statements and Supplementary Data" for additional information.

(In millions)	2019	2020-2021	2022-2023	After 2023	Total
Maturities of long-term debt (A)	$ 250.1	$ 0.2	$ 0.2	$ 2,929.5	$ 3,180.0
Operating lease obligations:					
Railcars	18.6	—	—	—	18.6
Wind farm land leases	2.5	5.8	5.8	37.6	51.7
Office space lease	1.0	1.6	—	—	2.6
Total operating lease obligations	22.1	7.4	5.8	37.6	72.9
Other purchase obligations and commitments:					
Cogeneration capacity and fixed operation and maintenance payments (B)	10.9	—	—	—	10.9
Expected cogeneration energy payments (B)	2.4	—	—	—	2.4
Minimum purchase commitments	75.8	89.2	89.2	370.4	624.6
Expected wind purchase commitments	56.3	114.0	115.5	448.0	733.8
Long-term service agreement commitments	46.8	4.8	16.8	108.9	177.3
Environmental compliance plan expenditures	5.8	0.2	—	—	6.0
Total other purchase obligations and commitments	198.0	208.2	221.5	927.3	1,555.0
Total contractual obligations	470.2	215.8	227.5	3,894.4	4,807.9
Amounts recoverable through fuel adjustment clause (C)	(153.1)	(203.2)	(204.7)	(818.4)	(1,379.4)
Total contractual obligations, net	$ 317.1	$ 12.6	$ 22.8	$ 3,076.0	$ 3,428.5

(A) Maturities of the Company's long-term debt during the next five years consist of $250.1 million, $0.1 million, $0.1 million, $0.1 million and $0.1 million in 2019, 2020, 2021, 2022 and 2023, respectively.
(B) Cogeneration capacity, fixed operation and maintenance and energy payments will end in 2019, as a result of contract expiration. As described below, OG&E intends to acquire the AES and Oklahoma Cogeneration LLC power plants, pending regulatory approval.
(C) 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.

As of December 31, 2018, OG&E has 440 MWs of QF contracts with AES and Oklahoma Cogeneration LLC to meet its current and future expected customer needs. The QF contract with AES expired on January 15, 2019, and the QF contract with Oklahoma Cogeneration LLC expires on August 31, 2019. On December 20, 2018, OG&E announced its plan to acquire power plants from AES and Oklahoma Cogeneration LLC, pending regulatory approval, to meet customers' energy needs. Further discussion can be found in Notes 14 and 15 in "Item 8. Financial Statements and Supplementary Data."

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 on 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 and the APSC.

Pension and Postretirement Benefit Plans

At December 31, 2018, 32.4 percent of the Pension Plan investments were in listed common stocks with the balance primarily invested in corporate fixed income, other securities and U.S. Treasury notes and bonds as presented in Note 12 in "Item 8. Financial Statements and Supplementary Data." During 2018, actual losses on the Pension Plan were $39.2 million, compared to expected return on plan assets of $44.1 million. During the same time, corporate bond yields, which are used in determining the discount rate for future pension obligations, decreased. Funding levels are dependent on returns on plan assets and future discount rates. The Company made a $15.0 million and $20.0 million contribution to its Pension Plan in 2018 and 2017, respectively. The Company has not determined whether it will need to make any contributions to the Pension Plan in 2019. 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, 2018 and 2017. 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 "Item 8. Financial Statements and Supplementary Data") 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)*	**2018**	2017	**2018**	2017	**2018**	2017
Benefit obligations	**$ 615.9**	$ 687.5	**$ 9.6**	$ 8.1	**$ 135.8**	$ 149.4
Fair value of plan assets	**522.8**	635.3	**—**	—	**45.3**	50.2
Funded status at end of year	**$ (93.1)**	$ (52.2)	**$ (9.6)**	$ (8.1)	**$ (90.5)**	$ (99.2)

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. At the Company's September 2018 board meeting, the Board of Directors approved management's recommendation of a 10 percent increase in the quarterly dividend rate to $0.3650 per share from $0.3325 per share effective in October 2018.

Financing Activities and Future Sources of Financing

Management expects that cash generated from operations, proceeds from the issuance of long- and short-term debt, proceeds from the sales of common stock to the public through the Company's Automatic Dividend Reinvestment and Stock Purchase Plan or other offerings and distributions from Enable will be adequate over the next three years to meet anticipated cash needs and to fund future growth opportunities. The Company utilizes short-term borrowings (through a combination of bank borrowings and commercial paper) to satisfy temporary working capital needs and as an interim source of financing capital expenditures until permanent financing is arranged.

Short-Term Debt and Credit Facilities

Short-term borrowings generally are used to meet working capital requirements. The Company borrows on a short-term basis, as necessary, by the issuance of commercial paper and by borrowings under its revolving credit agreement. The Company has revolving credit facilities totaling $900.0 million. These bank facilities can also be used as letter of credit facilities. As of December 31, 2018, the Company had no short-term debt outstanding compared to $168.4 million at December 31, 2017. The following tables highlight the Company's short-term debt activity as of and for the year ended December 31, 2018.

(*Dollars in millions*)		**December 31, 2018**
Balance of outstanding supporting letters of credit	$	0.3
Weighted-average interest rate of outstanding supporting letters of credit		1.05%
Net available liquidity under revolving credit agreements	$	899.7
Balance of cash and cash equivalents	$	94.3

(*Dollars in millions*)		**Year Ended December 31, 2018**
Average balance of short-term debt	$	128.9
Weighted-average interest rate of average balance of short-term debt		2.10%
Maximum month-end balance of short-term debt	$	289.0

In March 2017, the Company and OG&E entered into unsecured five-year revolving credit agreements totaling $900.0 million ($450.0 million for the Company and $450.0 million for OG&E). Each of the facilities contained an option, which could be exercised up to two times, to extend the term of the respective facility for an additional year. Effective March 9, 2018, the Company and OG&E utilized one of those extensions to extend the maturity of their respective credit facility from March 8, 2022 to March 8, 2023.

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, 2019 and ending December 31, 2020. See Note 11 in "Item 8. Financial Statements and Supplementary Data" for further discussion of the Company's short-term debt activity.

Issuance of Long-Term Debt

In August 2018, OG&E issued $400.0 million of 3.80 percent senior notes due August 15, 2028. The proceeds from the issuance were added to OG&E's general funds to be used for general corporate purposes, including to fund the payment of OG&E's $250.0 million of 6.35 percent senior notes that matured on September 1, 2018, to repay short-term debt and to fund ongoing capital expenditures and working capital.

Security Ratings

	Moody's Investors Service	**S&P's Global Ratings**	**Fitch Ratings**
OG&E Senior Notes	A2	BBB+	A
OGE Energy Senior Notes	Baa1	BBB+	BBB+
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.

On March 5, 2018, S&P's Global Ratings revised the rating outlooks on the Company and OG&E from stable to negative. S&P's Global Ratings indicated that the revised outlooks reflect the limited cushion in company financial measures, which incorporate higher capital spending plans and the effects of the 2017 Tax Act, and uncertainty regarding regulatory risk. The revised outlooks did not trigger any collateral requirements or change fees under the revolving credit agreements.

On June 18, 2018, S&P's Global Ratings lowered its issuer credit ratings for the Company and OG&E from A- to BBB+ and revised their rating outlooks from negative to stable. S&P's Global Ratings also lowered its rating on OG&E's senior unsecured notes from A- to BBB+. S&P's Global Ratings indicated that the changes in ratings are a result of the $64.0 million rate decrease in the June 19, 2018 OCC settlement, the existing level of depreciation expense and continued capital spending, which places the Company and OG&E at a higher level of financial risk in S&P's Global Ratings' risk profile. Furthermore, S&P's Global Ratings indicated that the Company's change in credit rating was impacted by Enable's business risk, due to the volatility of the oil and gas industry. However, S&P's Global Ratings indicated that the stable outlook reflects its expectation that the Company and OG&E will be able to manage future regulatory risk in Oklahoma.

On July 11, 2018, Moody's Investors Service lowered its rating from A3 to Baa1 for the Company and from A1 to A2 for OG&E with both companies having negative outlooks. The Oklahoma regulatory environment and the 2017 Tax Act were both cited by Moody's Investors Service as contributing factors to the credit downgrade. Moody's Investors Service indicated that the negative outlook for OG&E is a reflection of current capital expenditures relating to environmental projects, upcoming debt maturities over the next year and decreased cash flow as a result of the 2017 Tax Act. In addition to the OG&E impacts, Moody's Investors Service indicated that the negative outlook for the Company is a reflection of Enable's business risk, due to the volatility of the oil and gas industry, which Moody's Investors Service indicated could lead to decreased distributions.

On August 1, 2018, Fitch Ratings lowered its senior unsecured debt rating from A- to BBB+ for the Company and from A+ to A for OG&E with both companies having stable outlooks. Fitch Ratings cited the regulatory environment in Oklahoma, underscored by the unfavorable rate review outcomes in 2017 and 2018 and uncertainty surrounding regulatory treatment for OG&E's investment in the Dry Scrubbers at Sooner Units 1 and 2, as a key contributing factor to the credit downgrade. Fitch Ratings also indicated that the Company's credit profile reflects Enable's higher operating risks.

The Company's and OG&E's borrowing costs under the credit agreements will increase immaterially as a result of these recent credit downgrades.

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.

Common Stock

The Company does not expect to issue any common stock in 2019 from its Automatic Dividend Reinvestment and Stock Purchase Plan. See Note 9 in "Item 8. Financial Statements and Supplementary Data" for a discussion of the Company's common stock activity.

Distributions by Enable

Pursuant to the Enable Limited Partnership Agreement, Enable made distributions of $141.2 million, $141.2 million and $141.2 million to the Company during the years ended December 31, 2018, 2017 and 2016, respectively. As required by Enable's Limited Partnership Agreement and General Partner Agreement, respectively, the last permitted distribution date is 60 days after the close of each quarter, and the distribution deadline is five days following distributions by Enable.

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 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 Audit Committee of the Company's Board of Directors. 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 in "Item 8. Financial Statements and Supplementary Data."

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. 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 in "Item 8. Financial Statements and Supplementary Data." 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. Funding levels are 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	+/- $5.2 million
Discount rate	+/- 0.25 percent	+/- $11.4 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. See Note 8 in "Item 8. Financial Statements and Supplementary Data" for discussion of the effects of the 2017 Tax Act and other tax policies.

Asset Retirement Obligations

The Company has recorded asset retirement obligations that are being accreted over their respective lives ranging from two 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, 2018, 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 $0.4 million. At December 31, 2018 and 2017, Accrued Unbilled Revenues were $62.6 million and $66.5 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, which 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, 2018, if the provision rate were to increase or decrease by 10 percent, this would cause a change in the uncollectible expense recognized of $0.2 million. The allowance for uncollectible accounts receivable is a reduction to Accounts Receivable on the Consolidated Balance Sheets and is included in the Other Operation and Maintenance Expense on the Consolidated Statements of Income. The allowance for uncollectible accounts receivable was $1.7 million and $1.5 million at December 31, 2018 and 2017, respectively.

Accounting Pronouncements

See Note 2 in "Item 8. Financial Statements and Supplementary Data" 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 in "Item 8. Financial Statements and Supplementary Data" and "Item 3. Legal Proceedings" 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 the Company's business activities in many ways, including the handling or disposal of waste material, planning for future construction activities to avoid or mitigate harm to threatened or endangered species and requiring the installation and operation of emissions 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. Management believes that all of 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. 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 2019 will be $50.0 million, of which $25.5 million is for capital expenditures. The amounts for OG&E include capital expenditures for the Dry Scrubbers at Sooner Units 1 and 2 and the conversion of Muskogee Units 4 and 5 to natural gas. It is estimated that OG&E's total expenditures to comply with environmental laws, regulations and requirements for 2020 will be $22.6 million, of which $0.2 million is for capital expenditures.

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 U.S. that may be impacted by air pollutant emissions. On December 28, 2011, the EPA issued a final Regional Haze Rule for Oklahoma which adopted a FIP for SO_2 emissions at Sooner Units 1 and 2 and Muskogee Units 4 and 5. The FIP compliance date was January 4, 2019 as a result of an appeal filed by OG&E and others.

To satisfy the FIP, OG&E installed Dry Scrubbers at Sooner Units 1 and 2 and is converting Muskogee Units 4 and 5 to natural gas. As of December 31, 2018, OG&E has invested $504.3 million in the Dry Scrubbers and $50.5 million in the Muskogee natural gas conversion.

Cross-State Air Pollution Rule

In August 2011, the EPA finalized its CSAPR that required 27 states in the eastern half of the U.S. (including Oklahoma) to reduce power plant emissions that contribute to ozone and particulate matter pollution in other states. Litigation challenging the rule delayed the effective date until 2014. Several parties to that litigation, including OG&E, have petitions for review that remain pending although the rule is now effective. Compliance with the CSAPR began in 2015 using the amount of allowances originally scheduled to be available in 2012. OG&E has installed seven low NO_X burner systems on two Muskogee units, two Sooner units and three Seminole units and is in compliance.

On September 7, 2016, the EPA finalized an update to the 2011 CSAPR. The new rule applies to ozone-season NO_X in 22 eastern states (including Oklahoma), utilizes a cap and trade program for NO_X emissions and went into effect on May 1, 2017. The rule reduces the 2016 CSAPR emissions cap for all seven of OG&E's coal and gas facilities by 47 percent combined. OG&E and numerous other parties filed petitions for judicial and administrative review of the 2016 rule. Oral argument before the D.C. Circuit U.S. Court of Appeals was held on October 3, 2018.

Due to the pending litigation and administrative proceedings, the ultimate timing and impact of the 2016 CSAPR update rule on our operations cannot be determined with certainty at this time. However, the Company does not anticipate additional capital expenditures beyond what has already been disclosed and does not expect that the reduced emissions cap, if upheld, will have a material impact on the Company's consolidated financial position, results of operations or cash flows.

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 Company complied with the MATS rule by the April

16, 2016 deadline that applied to OG&E by installing activated carbon injection for all five coal units. Nonetheless, there is continuing litigation, to which the Company is not a party, challenging whether the EPA had statutory authority to issue the MATS rule. On December 27, 2018, the EPA released a proposed rule reconsidering certain elements of the 2012 rule in response to lengthy litigation in the D.C. Circuit Court. The proposed rule will be available for public comment when it is published in the Federal Register. The Company cannot predict the outcome of this litigation or regulatory proposal or how it will affect the Company.

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 December 31, 2018, 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 EPA proposed to designate part of Muskogee County, in which OG&E's Muskogee Power Plant is located, as non-attainment for the 2010 SO_2 NAAQS on March 1, 2016, even though nearby monitors indicate compliance with the NAAQS. The proposed designation is based on modeling that does not reflect the planned conversion of two of the coal units at Muskogee to natural gas. OG&E commented that the EPA should defer a designation of the area to allow time for additional monitoring. The State of Oklahoma's revised monitoring plan was approved by the EPA, and the required monitoring commenced at the beginning of 2017 and will continue through the end of 2019. Nonetheless, the EPA has a deadline for making a decision on the designation pursuant to a consent decree entered by the U.S. District Court for the Northern District of California to resolve a citizen suit. The deadline has been extended several times, with the current deadline being August 26, 2017, but a decision has yet to be reached. It is unclear what impact, if any, the consent decree deadline will have on the monitoring plan. At this time, OG&E cannot determine with any certainty whether the proposed designation of Muskogee County will cause a material impact to OG&E's financial results. The EPA has published final decisions on all other areas of Oklahoma. In this decision, Noble County, in which the Sooner plant is located, was deemed to be in attainment with the 2010 standard.

On September 30, 2015, the EPA finalized a NAAQS for ozone at 70 ppb, which is more stringent than the previous standard of 75 ppb set in 2008. In September 2016, Oklahoma submitted to the EPA the recommendation of "attainment/unclassifiable" for all 77 counties in Oklahoma. On June 4, 2018, the EPA published its final determination that there are no nonattainment areas in Oklahoma. Based on this assessment, no material impacts are anticipated at this time.

The Company continues to monitor these 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.

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. On June 1, 2017, President Trump announced that the U.S. will withdraw from the Paris Climate Accord and begin negotiations to re-enter the agreement with different terms. A new agreement may result in future additional emissions reductions in the U.S.; 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 these commitments will be implemented through the Clean Air Act or any other existing statutes and new legislation.

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 consolidated financial position, results of operations and cash flows if such costs are not recovered through regulated rates. Several states outside the area where the Company operates 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.

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. However, the rule was challenged in court when it was issued, and the U.S. Supreme Court issued orders staying implementation of the Clean Power Plan on February 9, 2016 pending resolution of the court challenges. The EPA published a proposal on October 16, 2017 to repeal the Clean Power Plan. On August 31, 2018, without acting on the proposed repeal of the Clean Power Plan, the EPA published the Affordable Clean Energy Rule, a proposed rule to replace the Clean Power Plan. The ultimate timing and impact of these standards on OG&E's operations cannot be determined with certainty at this time, although a requirement for significant reduction of CO_2 emissions from existing fossil-fuel-fired power plants ultimately could result in significant additional compliance costs that would affect the Company's future consolidated financial position, results of operations and cash flows if such costs are not recovered through regulated rates.

Nonetheless, OG&E's current business strategy will result in a reduced carbon emissions rate compared to current levels. As discussed in Note 15 in "Item 8. Financial Statements and Supplementary Data" under "Pending Regulatory Matters," OG&E's plan to comply with the EPA's MATS rule and Regional Haze Rule FIP includes converting two coal-fired generating units at the 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 is also deploying more renewable energy sources that do not emit greenhouse gases. OG&E's service territory borders one of the nation's best wind resource areas, and 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 areas 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 provisions in the SIPs 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. Although judicial challenges to the rule are ongoing, the Oklahoma Department of Environmental Quality submitted a SIP revision for the EPA's approval on November 7, 2016 to comply with this rule. This rule has resulted in permit modifications for certain OG&E units. The Company does not anticipate capital expenditures or a material impact to its consolidated financial position, results of operations or cash flows, as a result of adoption of this rule.

Air Quality Control System

The Dry Scrubber system on Sooner Unit 1 completed certain emission testing in October 2018 and was placed into service. The Dry Scrubber system on Sooner Unit 2 completed certain emission testing in January 2019 and was placed into service. More detail regarding the ECP can be found under "Pending Regulatory Matters" in Note 15 in "Item 8. Financial Statements and Supplementary Data."

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.

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.

In 2015, 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 rule regulates coal ash as a solid waste rather than a hazardous waste, which would have made the management of coal ash more costly. Recent litigation decisions at the D.C. Circuit Court of Appeals indicate that the EPA will be required to revise certain aspects of this rule. OG&E manages one regulated inactive coal ash impoundment that is expected to be clean-closed in 2019. On June 28, 2018, the EPA approved the State of Oklahoma's application for a state coal ash permitting program that will operate in lieu of the federal coal ash program promulgated under the Federal Resource Conservation and Recovery Act. The EPA approval of the State of Oklahoma permitting program is currently under litigation. The Company is monitoring regulatory developments relating to this rule, none of which appear to be material to OG&E at this time. OG&E is in compliance with this rule at this time.

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 2018, the Company obtained refunds of $1.9 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 Oklahoma Department of Environmental Quality issued final permits on December 22, 2017 and August 22, 2018 for Muskogee Power Plant and Seminole Power Plant, respectively, in compliance with the final 316(b) rule, and OG&E did not incur any material costs associated with the rule's implementation at either location. OG&E expects to be able to provide a reasonable estimate of any material costs associated with the rule's implementation at other facilities following the future issuance of permits from the State of Oklahoma.

In 2015, the EPA issued a final rule addressing the effluent limitation guidelines for power plants under the Federal Clean Water Act. The final rule establishes technology and performance based standards that may apply to discharges of six waste streams including bottom ash transport water. Compliance with this rule will occur by 2023; however, on April 12, 2017, the EPA granted a Petition for Reconsideration of the 2015 Rule. OG&E is evaluating what, if any, compliance actions are needed but is not able to quantify with any certainty what costs may be incurred. OG&E expects to be able to provide a reasonable estimate of any material costs associated with the rule's implementation following issuance of the permits from the State of Oklahoma.

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 generates 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 in "Item 8. Financial Statements and Supplementary Data."

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 would be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio, but the Company has no intent at this time to utilize interest rate derivatives.

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)*	**2019**	**2020**	**2021**	**2022**	**2023**	**Thereafter**	**Total**	**12/31/18 Fair Value**
Fixed-rate debt (A):								
Principal amount	$ 250.1	$ 0.1	$ 0.1	$ 0.1	$ 0.1	$ 2,794.1	$ 3,044.6	$ 3,186.9
Weighted-average interest rate	8.25%	4.48%	4.48%	4.48%	4.48%	4.74%	5.03%	
Variable-rate debt (B):								
Principal amount	$ —	$ —	$ —	$ —	$ —	$ 135.4	$ 135.4	$ 135.4
Weighted-average interest rate	—%	—%	—%	—%	—%	1.79%	1.79%	

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

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

Item 8. Financial Statements and Supplementary Data.

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF INCOME

Year Ended December 31 *(In millions except per share data)*	**2018**	2017	2016
OPERATING REVENUES			
Revenues from contracts with customers	**$ 2,211.7**	$ —	$ —
Other revenues	**58.6**	—	—
Operating revenues	**2,270.3**	2,261.1	2,259.2
COST OF SALES	**892.5**	897.6	880.1
OPERATING EXPENSES			
Other operation and maintenance	**474.6**	458.7	438.1
Depreciation and amortization	**321.6**	283.5	322.6
Taxes other than income	**92.0**	89.4	87.6
Operating expenses	**888.2**	831.6	848.3
OPERATING INCOME	**489.6**	531.9	530.8
OTHER INCOME (EXPENSE)			
Equity in earnings of unconsolidated affiliates	**152.8**	131.2	101.8
Allowance for equity funds used during construction	**23.8**	39.7	14.2
Other net periodic benefit expense	**(10.8)**	(21.6)	(27.5)
Other income	**21.7**	46.4	26.0
Other expense	**(23.4)**	(14.1)	(16.9)
Net other income	**164.1**	181.6	97.6
INTEREST EXPENSE			
Interest on long-term debt	**157.4**	153.6	143.2
Allowance for borrowed funds used during construction	**(11.7)**	(18.0)	(7.5)
Interest on short-term debt and other interest charges	**10.3**	8.2	6.4
Interest expense	**156.0**	143.8	142.1
INCOME BEFORE TAXES	**497.7**	569.7	486.3
INCOME TAX EXPENSE (BENEFIT)	**72.2**	(49.3)	148.1
NET INCOME	**$ 425.5**	$ 619.0	$ 338.2
BASIC AVERAGE COMMON SHARES OUTSTANDING	**199.7**	199.7	199.7
DILUTED AVERAGE COMMON SHARES OUTSTANDING	**200.5**	200.0	199.9
BASIC EARNINGS PER AVERAGE COMMON SHARE	**$ 2.13**	$ 3.10	$ 1.69
DILUTED EARNINGS PER AVERAGE COMMON SHARE	**$ 2.12**	$ 3.10	$ 1.69
DIVIDENDS DECLARED PER COMMON SHARE	**$ 1.39500**	$ 1.27000	$ 1.15500

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)*	**2018**	2017	2016
Net income	**$ 425.5**	$ 619.0	$ 338.2
Other comprehensive income (loss), net of tax:			
Pension Plan and Restoration of Retirement Income Plan:			
Amortization of deferred net loss, net of tax of $1.1, $1.4 and $1.7, respectively	**3.3**	2.5	2.8
Amortization of prior service cost, net of tax of $0.0, $0.0 and $0.0, respectively	**—**	(0.1)	—
Net gain (loss) arising during the period, net of tax of ($4.7), $0.2 and ($0.6), respectively	**(14.1)**	0.4	(0.7)
Settlement cost, net of tax of $1.6, $1.4 and $3.2, respectively	**4.7**	2.2	5.0
Postretirement Benefit Plans:			
Amortization of prior service credit, net of tax of ($0.6), ($0.3) and ($1.0), respectively	**(1.7)**	(0.6)	(1.5)
Prior service cost arising during the period, net of tax of $0.0, $4.0 and $0.0, respectively	**—**	6.3	—
Net gain (loss) arising during the period, net of tax of $0.7, ($0.2) and $0.1, respectively	**2.1**	(0.6)	0.2
Settlement cost, net of tax of $0.0, $0.2 and $0.0, respectively	**—**	0.5	—
Other comprehensive income (loss), net of tax	**(5.7)**	10.6	5.8
Comprehensive income	**$ 419.8**	$ 629.6	$ 344.0

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)*	**2018**	2017	2016
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	**$ 425.5**	$ 619.0	$ 338.2
Adjustments to reconcile net income to net cash provided from operating activities:			
Depreciation and amortization	**321.6**	283.5	322.6
Deferred income taxes and investment tax credits, net	**78.5**	(50.0)	153.8
Equity in earnings of unconsolidated affiliates	**(152.8)**	(131.2)	(101.8)
Distributions from unconsolidated affiliates	**141.2**	131.2	102.3
Allowance for equity funds used during construction	**(23.8)**	(39.7)	(14.2)
Stock-based compensation expense	**13.4**	9.1	4.7
Regulatory assets	**(10.8)**	3.7	(21.4)
Regulatory liabilities	**(16.5)**	(3.7)	(11.8)
Other assets	**6.2**	(0.7)	15.4
Other liabilities	**1.0**	(65.5)	(18.9)
Change in certain current assets and liabilities:			
Accounts receivable and accrued unbilled revenues, net	**19.8**	(21.8)	(6.9)
Income taxes receivable	**(4.1)**	13.6	(2.2)
Fuel, materials and supplies inventories	**27.3**	(3.6)	32.4
Fuel recoveries	**(3.4)**	53.0	(112.6)
Other current assets	**25.1**	27.2	(26.2)
Accounts payable	**29.7**	27.1	(45.1)
Other current liabilities	**73.2**	(66.7)	36.4
Net cash provided from operating activities	**951.1**	784.5	644.7
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures (less allowance for equity funds used during construction)	**(573.6)**	(824.1)	(660.1)
Investment in unconsolidated affiliates	**(2.5)**	(8.5)	—
Return of capital - unconsolidated affiliates	**—**	10.0	38.8
Proceeds from sale of assets	**0.1**	0.7	0.9
Net cash used in investing activities	**(576.0)**	(821.9)	(620.4)
CASH FLOWS FROM FINANCING ACTIVITIES			
(Decrease) increase in short-term debt	**(168.4)**	(67.8)	236.2
Proceeds from long-term debt	**396.0**	592.1	—
Payment of long-term debt	**(250.1)**	(225.1)	(110.2)
Dividends paid on common stock	**(272.2)**	(247.6)	(225.1)
Expense of common stock	**(0.1)**	(0.1)	—
Other	**(0.4)**	—	(0.1)
Net cash (used in) provided from financing activities	**(295.2)**	51.5	(99.2)
NET CHANGE IN CASH AND CASH EQUIVALENTS	**79.9**	14.1	(74.9)
CASH AND CASH EQUIVALENTS AT BEGINNING OF PERIOD	**14.4**	0.3	75.2
CASH AND CASH EQUIVALENTS AT END OF PERIOD	**$ 94.3**	$ 14.4	$ 0.3

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

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS

December 31 *(In millions)*	**2018**	2017
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	**$ 94.3**	$ 14.4
Accounts receivable, less reserve of $1.7 and $1.5, respectively	**174.7**	190.6
Accrued unbilled revenues	**62.6**	66.5
Income taxes receivable	**9.9**	5.8
Fuel inventories	**57.6**	84.3
Materials and supplies, at average cost	**126.7**	80.8
Fuel clause under recoveries	**2.0**	—
Other	**29.5**	54.6
Total current assets	**557.3**	497.0
OTHER PROPERTY AND INVESTMENTS		
Investment in unconsolidated affiliates	**1,177.5**	1,160.4
Other	**73.4**	76.7
Total other property and investments	**1,250.9**	1,237.1
PROPERTY, PLANT AND EQUIPMENT		
In service	**11,994.8**	11,041.2
Construction work in progress	**376.4**	867.5
Total property, plant and equipment	**12,371.2**	11,908.7
Less accumulated depreciation	**3,727.4**	3,568.8
Net property, plant and equipment	**8,643.8**	8,339.9
DEFERRED CHARGES AND OTHER ASSETS		
Regulatory assets	**285.8**	283.0
Other	**10.8**	55.7
Total deferred charges and other assets	**296.6**	338.7
TOTAL ASSETS	**$ 10,748.6**	$ 10,412.7

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

OGE ENERGY CORP.
CONSOLIDATED BALANCE SHEETS (Continued)

December 31 *(In millions)*	**2018**	2017
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Short-term debt	**$ —**	$ 168.4
Accounts payable	**239.3**	230.4
Dividends payable	**72.9**	66.4
Customer deposits	**83.6**	80.7
Accrued taxes	**44.0**	44.5
Accrued interest	**44.5**	44.0
Accrued compensation	**47.8**	35.9
Long-term debt due within one year	**250.0**	249.8
Fuel clause over recoveries	**0.3**	1.7
Other	**87.0**	28.7
Total current liabilities	**869.4**	950.5
LONG-TERM DEBT	**2,896.9**	2,749.6
DEFERRED CREDITS AND OTHER LIABILITIES		
Accrued benefit obligations	**225.7**	192.7
Deferred income taxes	**1,310.9**	1,227.8
Regulatory liabilities	**1,270.7**	1,283.4
Other	**169.9**	157.6
Total deferred credits and other liabilities	**2,977.2**	2,861.5
Total liabilities	**6,743.5**	6,561.6
COMMITMENTS AND CONTINGENCIES (NOTE 14)		
STOCKHOLDERS' EQUITY		
Common stockholders' equity	**1,127.7**	1,114.8
Retained earnings	**2,906.3**	2,759.5
Accumulated other comprehensive loss, net of tax	**(28.9)**	(23.2)
Total stockholders' equity	**4,005.1**	3,851.1
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	**$ 10,748.6**	$ 10,412.7

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

OGE ENERGY CORP.
CONSOLIDATED STATEMENTS OF CAPITALIZATION

December 31 *(In millions except per share data)*			**2018**		2017
STOCKHOLDERS' EQUITY					
Common stock, par value $0.01 per share; authorized 450.0 shares; and outstanding 199.7 shares and 199.7 shares, respectively		**$**	**2.0**	$	2.0
Premium on common stock			**1,125.7**		1,112.8
Retained earnings			**2,906.3**		2,759.5
Accumulated other comprehensive loss, net of tax			**(28.9)**		(23.2)
Total stockholders' equity			**4,005.1**		3,851.1
LONG-TERM DEBT					
SERIES	DUE DATE				
Senior Notes - OG&E					
6.35%	Senior Notes, Series Due September 1, 2018		**—**		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
3.80%	Senior Notes, Series Due August 15, 2028		**400.0**		—
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
4.15%	Senior Notes, Series Due April 1, 2047		**300.0**		300.0
3.85%	Senior Notes, Series Due August 15, 2047		**300.0**		300.0
3.80%	Tinker Debt, Due August 31, 2062		**9.6**		9.7
Other Bonds - OG&E					
1.01% - 2.00%	Garfield Industrial Authority, January 1, 2025		**47.0**		47.0
1.01% - 1.83%	Muskogee Industrial Authority, January 1, 2025		**32.4**		32.4
1.03% - 1.86%	Muskogee Industrial Authority, June 1, 2027		**56.0**		56.0
Unamortized debt expense			**(22.9)**		(20.8)
Unamortized discount			**(10.2)**		(9.9)
Total long-term debt			**3,146.9**		2,999.4
Less: long-term debt due within one year			**(250.0)**		(249.8)
Total long-term debt (excluding long-term debt due within one year)			**2,896.9**		2,749.6
Total capitalization (including long-term debt due within one year)		**$**	**7,152.0**	$	6,850.5

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

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

(In millions)	Shares Outstanding		Common Stock		Premium on Common Stock		Retained Earnings		Accumulated Other Comprehensive (Loss) Income		Total
Balance at December 31, 2015	199.7	$	2.0	$	1,099.3	$	2,259.8	$	(35.1)	$	3,326.0
Net income	—		—		—		338.2		—		338.2
Other comprehensive income, net of tax	—		—		—		—		5.8		5.8
Dividends declared on common stock	—		—		—		(230.7)		—		(230.7)
Stock-based compensation	—		—		4.5		—		—		4.5
Balance at December 31, 2016	199.7	$	2.0	$	1,103.8	$	2,367.3	$	(29.3)	$	3,443.8
Net income	—		—		—		619.0		—		619.0
Cumulative effect of change in accounting principles	—		—		—		26.8		(4.5)		22.3
Other comprehensive income, net of tax	—		—		—		—		10.6		10.6
Dividends declared on common stock	—		—		—		(253.6)		—		(253.6)
Expense of common stock	—		—		(0.1)		—		—		(0.1)
Stock-based compensation	—		—		9.1		—		—		9.1
Balance at December 31, 2017	199.7	$	2.0	$	1,112.8	$	2,759.5	$	(23.2)	$	3,851.1
Net income	**—**		**—**		**—**		**425.5**		**—**		**425.5**
Other comprehensive loss, net of tax	**—**		**—**		**—**		**—**		**(5.7)**		**(5.7)**
Dividends declared on common stock	**—**		**—**		**—**		**(278.7)**		**—**		**(278.7)**
Expense of common stock	**—**		**—**		**(0.1)**		**—**		**—**		**(0.1)**
Stock-based compensation	**—**		**—**		**13.0**		**—**		**—**		**13.0**
Balance at December 31, 2018	**199.7**	**$**	**2.0**	**$**	**1,125.7**	**$**	**2,906.3**	**$**	**(28.9)**	**$**	**4,005.1**

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

1. Summary of Significant Accounting Policies

Organization

The Company is a holding company with investments in energy and energy services providers offering physical delivery and related services for both electricity and natural gas primarily in the south central U.S. 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 it lacks the power to direct activities that most significantly impact economic performance.

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 represents the Company's investment in Enable through wholly owned subsidiaries and ultimately OGE Holdings. Enable was formed in 2013, and its general partner is equally controlled by the Company and CenterPoint, who each have 50 percent management ownership. Based on the 50/50 management ownership, with neither company having control, the Company accounts for its interest in Enable using the equity method of accounting. Enable is primarily 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 Anadarko and Williston Basins. Enable has intrastate natural gas transportation and storage assets that are located in Oklahoma as well as interstate assets that extend from western Oklahoma and the Texas Panhandle to Louisiana, from Louisiana to Illinois and from Louisiana to Alabama.

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.

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:

December 31 *(In millions)*		**2018**		2017
REGULATORY ASSETS				
Current:				
Production tax credit rider under recovery (A)	**$**	**6.9**	$	—
Oklahoma demand program rider under recovery (A)		**6.4**		31.6
Fuel clause under recoveries		**2.0**		—
SPP cost tracker under recovery (A)		**—**		7.7
Other (A)		**3.2**		1.5
Total current regulatory assets	**$**	**18.5**	$	40.8
Non-current:				
Benefit obligations regulatory asset	**$**	**188.2**	$	177.2
Deferred storm expenses		**36.5**		42.2
Smart Grid		**25.6**		32.8
Unamortized loss on reacquired debt		**11.4**		12.3
Arkansas deferred pension expenses		**6.8**		5.1
Sooner Dry Scrubbers		**4.5**		—
Other		**12.8**		13.4
Total non-current regulatory assets	**$**	**285.8**	$	283.0
REGULATORY LIABILITIES				
Current:				
SPP cost tracker over recovery (B)	**$**	**16.8**	$	—
Reserve for tax refund (B)		**15.4**		—
Transmission cost recovery rider over recovery (B)		**2.7**		0.2
Fuel clause over recoveries		**0.3**		1.7
Other (B)		**1.4**		2.0
Total current regulatory liabilities	**$**	**36.6**	$	3.9
Non-current:				
Income taxes refundable to customers, net	**$**	**937.1**	$	955.5
Accrued removal obligations, net		**308.1**		288.4
Pension tracker		**18.7**		32.3
Other		**6.8**		7.2
Total non-current regulatory liabilities	**$**	**1,270.7**	$	1,283.4

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

As discussed in Note 15 under "Oklahoma Rate Review Filing - January 2018," as a result of the settlement agreement reached in the most recent Oklahoma rate review, OG&E removed production tax credits from base rates and now utilizes a separate rider to credit customers for production tax credits, which can either result in a regulatory asset or regulatory liability based on the differential between estimated and actual production tax credits included in the rider.

OG&E recovers program costs related to the Demand and Energy Efficiency Program in Oklahoma through the Demand Program Rider, which operates on a three year program cycle. The most recently concluded cycle allowed for recovery through December 2018 of energy efficiency program costs as well as associated lost revenues for achieved energy efficiency and demand savings and performance-based incentives. As discussed in Note 15 under "Demand Program Portfolio Filing," in December 2018, the OCC approved OG&E's 2019 through 2021 program cycle demand portfolio programs, which includes (i) energy efficiency program costs, (ii) lost revenues associated with certain achieved energy efficiency and demand savings, (iii) performance-based incentives and (iv) costs associated with research and development investments.

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

The benefit obligations regulatory asset is comprised of expenses recorded which are probable of future recovery and that have not yet been recognized as components of net periodic benefit cost, including net loss and prior service cost. These expenses are recorded as a regulatory asset as OG&E 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:

December 31 *(In millions)*	**2018**	2017
Pension Plan and Restoration of Retirement Income Plan:		
Net loss	**$ 185.3**	$ 172.4
Postretirement Benefit Plans:		
Net loss	**25.6**	33.6
Prior service cost	**(22.7)**	(28.8)
Total	**$ 188.2**	$ 177.2

The following amounts in the benefit obligations regulatory asset at December 31, 2018 are expected to be recognized as components of net periodic benefit cost in 2019:

(In millions)	
Pension Plan and Restoration of Retirement Income Plan:	
Net loss	**$ 13.8**
Postretirement Benefit Plans:	
Net loss	**2.7**
Prior service cost	**(6.1)**
Total	**$ 10.4**

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

OG&E deferred to a regulatory asset the incremental and stranded costs that were accumulated during Smart Grid deployment, including (i) costs for web portal access, (ii) costs for education and home energy reports and (iii) stranded costs associated with OG&E's analog electric meters, which have been replaced by smart meters. These costs have been included in the Smart Grid asset in the table above, and as approved in recent rate reviews in Oklahoma and Arkansas, these costs are now being recovered over a six year period.

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 expense 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 recovered as a part of OG&E's cost of capital.

Arkansas includes a certain level of pension expense in base rates. When the Pension Plan experiences a settlement, which represents an acceleration of future pension costs, OG&E defers to a regulatory asset the Arkansas jurisdictional portion of each settlement, which historically was recovered from customers over the average life of the remaining plan participants. A portion of these settlements is now being recovered in current rates, and additional amounts will be requested as additional settlements occur. For additional information related to settlements, see Note 12.

As discussed in Note 15 under "Oklahoma Rate Review Filing - January 2018," as the result of a settlement agreement reached in the most recent Oklahoma rate review, OG&E began deferring the non-fuel incremental operation and maintenance expenses, depreciation, debt cost associated with the capital investment and related ad valorem taxes for the Dry Scrubbers at Sooner Units 1 and 2 as a regulatory asset. Recovery of these costs was requested in OG&E's December 2018 rate review filing. For additional information on the Dry Scrubber project, see Note 15 under "Environmental Compliance Plan."

OG&E recovers certain SPP costs related to base plan charges from its customers and refunds certain SPP revenues received to its customers in Oklahoma through the SPP cost tracker and in Arkansas through the transmission cost recovery rider.

Further discussion of the Company's reserve for tax refund in response to OCC, APSC and FERC proceedings can be found in Notes 8 and 15.

Income taxes refundable to customers, net, represents the reduction in accumulated deferred income taxes resulting from the reduction in the federal income tax rate as part of the 2017 Tax Act and includes income taxes recoverable from customers that represent income tax benefits previously used to reduce OG&E's revenues (treated as regulatory assets). These liabilities will be returned to customers in varying amounts over approximately 80 years, and the assets will be amortized over the estimated remaining life of the assets to which they relate, as the temporary differences that generated the income tax benefits turn around.

Accrued removal obligations, net represents 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 reviews. 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 review as a regulatory asset or regulatory liability. These amounts have been recorded in the Pension tracker regulatory liability in the 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 or liabilities, 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 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, which 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 $1.7 million and $1.5 million at December 31, 2018 and 2017, 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 $57.6 million and $84.3 million at December 31, 2018 and 2017, 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 was 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, representing natural gas in storage to be removed from storage over four years. As of December 31, 2018, all cushion gas had been withdrawn from storage.

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 tables below present 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, 2018 *(In millions)*	**Percentage Ownership**	**Total Property, Plant and Equipment**	**Accumulated Depreciation**	**Net Property, Plant and Equipment**
McClain Plant (A)	**77%**	**$ 227.2**	**$ 78.2**	**$ 149.0**
Redbud Plant (A)(B)	**51%**	**$ 493.9**	**$ 145.3**	**$ 348.6**

(A) Construction work in progress was $0.2 million and $0.9 million for the McClain and Redbud Plants, respectively.
(B) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $56.3 million.

December 31, 2017 *(In millions)*	Percentage Ownership	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
McClain Plant (A)	77%	$ 226.8	$ 71.4	$ 155.4
Redbud Plant (A)(B)	51%	$ 496.6	$ 136.0	$ 360.6

(A) Construction work in progress was $0.4 million and $7.8 million for the McClain and Redbud Plants, respectively.
(B) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $50.8 million.

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

December 31, 2018 *(In millions)*	**Total Property, Plant and Equipment**	**Accumulated Depreciation**	**Net Property, Plant and Equipment**
OGE Energy:			
Property, plant and equipment	**$ 6.1**	**$ —**	**$ 6.1**
OGE Energy property, plant and equipment	**6.1**	**—**	**6.1**
OG&E:			
Distribution assets	**4,229.4**	**1,324.5**	**2,904.9**
Electric generation assets (A)	**4,657.2**	**1,572.8**	**3,084.4**
Transmission assets (B)	**2,846.7**	**534.2**	**2,312.5**
Intangible plant	**187.6**	**135.1**	**52.5**
Other property and equipment	**444.2**	**160.8**	**283.4**
OG&E property, plant and equipment	**12,365.1**	**3,727.4**	**8,637.7**
Total property, plant and equipment	**$ 12,371.2**	**$ 3,727.4**	**$ 8,643.8**

(A) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $56.3 million.
(B) This amount includes a plant acquisition adjustment of $3.3 million and accumulated amortization of $0.7 million.

December 31, 2017 *(In millions)*	Total Property, Plant and Equipment	Accumulated Depreciation	Net Property, Plant and Equipment
OGE Energy:			
Property, plant and equipment	$ 6.1	$ —	$ 6.1
OGE Energy property, plant and equipment	6.1	—	6.1
OG&E:			
Distribution assets	4,057.1	1,259.1	2,798.0
Electric generation assets (A)	4,475.0	1,493.5	2,981.5
Transmission assets (B)	2,767.7	506.5	2,261.2
Intangible plant	181.8	135.8	46.0
Other property and equipment	421.0	173.9	247.1
OG&E property, plant and equipment	11,902.6	3,568.8	8,333.8
Total property, plant and equipment	$ 11,908.7	$ 3,568.8	$ 8,339.9

(A) This amount includes a plant acquisition adjustment of $148.3 million and accumulated amortization of $50.8 million.
(B) This amount includes a plant acquisition adjustment of $3.3 million and accumulated amortization of $0.6 million.

OG&E's unamortized computer software costs, included in intangible plant above, were $44.3 million and $37.5 million at December 31, 2018 and 2017, respectively.

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

Year Ended December 31 *(In millions)*	**2018**	2017	2016
OGE Energy	**$ —**	$ 0.2	$ 1.4
OG&E	**9.6**	8.8	8.0
Total	**$ 9.6**	$ 9.0	$ 9.4

Depreciation and Amortization

The provision for depreciation, which was 2.7 percent and 2.5 percent of the average depreciable utility plant for 2018 and 2017, respectively, is calculated using the 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 2019, the provision for depreciation is projected to be 2.7 percent of the average depreciable utility plant.

Amortization of intangible assets is calculated using the straight-line method. Of the remaining amortizable intangible plant balance at December 31, 2018, 98.7 percent will be amortized over 10.4 years with the remaining 1.3 percent of the intangible plant balance at December 31, 2018 being amortized over 23.7 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 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 as adjusted for basis differences. The Company's maximum exposure to loss related to Enable is limited to the Company's equity investment in Enable at December 31, 2018 as presented in Note 13. 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 and 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 and are classified as investing activities in the Consolidated Statements of Cash Flows.

Asset Retirement Obligations

OG&E has asset retirement obligations primarily associated with the removal of company-owned wind turbines on leased land, as well as the removal of asbestos from certain power generating stations. The Company has recorded asset retirement obligations that are being accreted over their respective lives ranging from two to 74 years.

The following table summarizes changes to the Company's asset retirement obligations during the years ended December 31, 2018 and 2017.

(In millions)	**2018**	2017
Balance at January 1	**$ 75.1**	$ 69.6
Accretion expense	**3.4**	3.1
Revisions in estimated cash flows (A)	**6.8**	2.4
Liabilities settled	**(1.4)**	—
Balance at December 31	**$ 83.9**	$ 75.1

(A) Assumptions changed related to the estimated timing and estimated cost of ash pond removal at one of OG&E's generating facilities.

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 $23.4 million and $17.1 million in accrued environmental liabilities at December 31, 2018 and 2017, respectively, which are included in the Company's asset retirement obligations.

Allowance for Funds Used During Construction

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 is calculated according to the FERC requirements for the imputed cost of equity and borrowed funds. Allowance for funds used during construction rates, compounded semi-annually, were 7.6 percent, 8.2 percent and 8.2 percent for the years ended December 31, 2018, 2017 and 2016, respectively.

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. The performance obligation to deliver electricity is generally created and satisfied simultaneously, and the provisions of the regulatory-approved tariff determine the charges OG&E may bill the customer, payment due date and other pertinent rights and obligations of both parties. 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 Revenues from Contracts with Customers 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.

Integrated Market and Transmission

OG&E currently owns and operates transmission and generation facilities as part of a vertically integrated utility. OG&E is a member of the SPP regional transmission organization and has transferred operational authority, but not ownership, of OG&E's transmission facilities to the SPP. The SPP has 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. Purchases and sales are based on the fixed transaction price determined by the market at the time of the purchase or sale and the MWh quantity purchased or sold. These results are reported as Revenues from Contracts with Customers or Cost of Sales in the 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.

OG&E's transmission revenues are generated by the use of OG&E's transmission network by the SPP, which operates the network, on behalf of other transmission owners. OG&E recognizes revenue on the sale of transmission service to its customers over time as the service is provided in the amount OG&E has a right to invoice. Transmission service to the SPP is billed monthly based on a fixed transaction price determined by OG&E's FERC-approved formula transmission rates along with other SPP-specific charges and the megawatt quantity reserved.

Other Revenues

Revenues from Alternative Revenue Programs

Other Revenues on the Consolidated Statements of Income is comprised of certain rider revenue that includes alternative revenue measures as defined in ASC 980, "Regulated Operations," which details two types of alternative revenue programs. The first type adjusts billings for the effects of weather abnormalities or broad external factors or to compensate OG&E for demand-side management initiatives (i.e., no-growth plans and similar conservation efforts). The second type provides for additional billings (i.e., incentive awards) for the achievement of certain objectives, such as reducing costs, reaching specified milestones or demonstratively improving customer service. Once the specific events permitting billing of the additional revenues under either program type have been completed, OG&E recognizes the additional revenues if (i) the program is established by an order from OG&E's regulatory commission that allows for automatic adjustment of future rates; (ii) the amount of additional revenues for the period is objectively determinable and is probable of recovery; and (iii) the additional revenues will be collected within 24 months following the end of the annual period in which they are recognized.

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 and the APSC.

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 the Company during 2017 and 2018. All amounts below are presented net of tax.

	Pension Plan and Restoration of Retirement Income Plan		Postretirement Benefit Plans		
(In millions)	Net Income (Loss)	Prior Service Cost (Credit)	Net Income (Loss)	Prior Service Cost (Credit)	Total
Balance at December 31, 2016	$ (32.1)	$ 0.1	$ 2.7	$ —	$ (29.3)
Other comprehensive income (loss) before reclassifications	0.4	—	(0.6)	6.3	6.1
Amounts reclassified from accumulated other comprehensive income (loss)	2.5	(0.1)	—	(0.6)	1.8
Cumulative effect of change in accounting principle	(5.7)	—	(0.1)	1.3	(4.5)
Settlement cost	2.2	—	0.5	—	2.7
Net current period other comprehensive income	(0.6)	(0.1)	(0.2)	7.0	6.1
Balance at December 31, 2017	(32.7)	—	2.5	7.0	(23.2)
Other comprehensive income (loss) before reclassifications	**(14.1)**	**—**	**2.1**	**—**	**(12.0)**
Amounts reclassified from accumulated other comprehensive income (loss)	**3.3**	**—**	**—**	**(1.7)**	**1.6**
Settlement cost	**4.7**	**—**	**—**	**—**	**4.7**
Net current period other comprehensive income (loss)	**(6.1)**	**—**	**2.1**	**(1.7)**	**(5.7)**
Balance at December 31, 2018	**$ (38.8)**	**$ —**	**$ 4.6**	**$ 5.3**	**$ (28.9)**

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, 2018 and 2017.

Details about Accumulated Other Comprehensive Income (Loss) Components	**Amount Reclassified from Accumulated Other Comprehensive Income (Loss)**		**Affected Line Item in the Consolidated Statements of Income**
	Year Ended December 31,		
(In millions)	**2018**	2017	
Amortization of Pension Plan and Restoration of Retirement Income Plan items:			
Actuarial losses (A)	**$ (4.4)**	$ (3.9)	Other Net Periodic Benefit Expense
Prior service cost	**—**	0.1	Other Net Periodic Benefit Expense
Settlement cost (A)	**(6.3)**	(3.6)	Other Net Periodic Benefit Expense
	(10.7)	(7.4)	Income Before Taxes
	(2.7)	(2.8)	Income Tax Expense (Benefit)
	$ (8.0)	$ (4.6)	Net Income
Amortization of postretirement benefit plans items:			
Prior service cost	**$ 2.3**	$ 0.9	Other Net Periodic Benefit Expense
Settlement cost (A)	**—**	(0.7)	Other Net Periodic Benefit Expense
	2.3	0.2	Income Before Taxes
	0.6	0.1	Income Tax Expense (Benefit)
	$ 1.7	$ 0.1	Net Income
Total reclassifications for the period	**$ (6.3)**	$ (4.5)	Net Income

(A) These accumulated other comprehensive 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 (gain) at December 31, 2018 that are expected to be recognized into earnings in 2019 are as follows:

(In millions)	
Pension Plan and Restoration of Retirement Income Plan:	
Net gain	**$ (4.9)**
Postretirement Benefit Plans:	
Net loss	**0.3**
Prior service cost	**2.3**
Total, net of tax	**$ (2.3)**

Reclassifications

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

Amounts for the years ended December 31, 2017 and 2016 have been adjusted for the reclassification of net periodic benefit cost components and the regulatory Pension tracker mechanism between Other Operation and Maintenance and Other Net Periodic Benefit Expense in the Company's Consolidated Statements of Income to be consistent with the 2018 presentation due to the Company's adoption of ASU 2017-07, "Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost." Further discussion can be found in Note 12.

2. Accounting Pronouncements

Recently Adopted Accounting Standards

Revenue from Contracts with Customers. In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers (Topic 606)." The Company adopted this standard in the first quarter of 2018 utilizing the modified retrospective transition method and applied the new standard only to contracts that were not completed at the date of initial application. The Company determined it was not necessary to change the timing or amounts of revenue recognized based on the adoption of Topic 606. Therefore, financial statement amounts in the period of adoption have not changed under Topic 606 as compared with the guidance that was in effect before the adoption of Topic 606. The adoption did change financial statement presentation as Operating Revenues are now separated between Revenues from Contracts with Customers and Other Revenues in the 2018 Consolidated Statements of Income. In addition, gains and losses associated with OG&E's guaranteed flat bill program that were previously included in Net Other Income in the Consolidated Statements of Income are now presented as Revenues from Contracts with Customers since the gains and losses are included within the transaction price in the contract under Topic 606. Operating Revenues presented in the 2017 Consolidated Statements of Income did not change from prior year. Alternative revenue programs are scoped out of Topic 606, as these programs are considered agreements between an entity and a regulator, not contracts between an entity and a customer; therefore, the Company now presents revenues from alternative revenue programs separately from revenues from contracts with customers. Further discussion regarding the Company's revenue recognition as well as additional disclosures resulting from the adoption of Topic 606 can be found in Notes 1 and 3.

Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets. In February 2017, the FASB issued ASU 2017-05, "Other Income - Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20): Clarifying the Scope of Asset Derecognition Guidance and Accounting for Partial Sales of Nonfinancial Assets." ASC 610-20 was issued as part of ASU 2014-09 and was added to provide guidance for recognizing gains and losses from the transfer of nonfinancial assets in contracts with non-customers. The new guidance clarifies the application of the guidance in Topic 606 for the derecognition of nonfinancial assets and unifies guidance related to partial sales of nonfinancial assets. The Company adopted the new guidance beginning in the first quarter of 2018, which did not have a material effect on its Consolidated Financial Statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost. In May 2017, the FASB issued ASU 2017-07, "Compensation-Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost." The new guidance is designed to improve the reporting of pension and other postretirement benefit costs by bifurcating the components of net benefit cost between those that are attributed to compensation for service and those that are not. The service cost component of benefit cost continues to be presented within operating income, but entities are now required to present the other components of benefit cost as non-operating within the income statement. Additionally, the new guidance only permits the capitalization of the service cost component of net benefit cost. The accounting change is required to be applied on a retrospective basis for the presentation of components of net benefit cost and on a prospective basis for the capitalization of only the service cost component of net benefit costs. The Company adopted the new guidance beginning in the first quarter of 2018. The presentation and recognition impacts of the Company's adoption of ASU 2017-07 are further discussed in Note 12.

Recognition and Measurement of Financial Assets and Financial Liabilities. In January 2016, the FASB issued ASU 2016-01, "Financial Instruments-Overall (Subtopic 825-10): Recognition and Measurement of Financial Assets and Financial Liabilities." The new guidance, among other things, requires entities to measure equity instruments (except those accounted for under the equity method of accounting or those that result in consolidation of the investee) at fair value with changes in fair value recognized in net income. Further, an entity has the option to measure equity instruments that do not have readily determinable fair values at cost minus impairment, if any, plus or minus changes resulting from observable price changes in orderly transactions for the identical or similar investment of the same issuer. The Company adopted the new guidance beginning in the first quarter of 2018, which did not have a material effect on its Consolidated Financial Statements.

Leases. In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)." The main difference between prior lease accounting and Topic 842 is the recognition of right-of-use assets and lease liabilities by lessees for those leases classified as operating leases under prior accounting guidance. Lessees, such as the Company, will need to recognize a right-of-use asset and a lease liability for virtually all of their leases, other than leases that meet the definition of a short-term lease. The liability will be equal to the present value of lease payments. The asset will be based on the liability, subject to adjustment for items such as initial direct costs. For income statement purposes, Topic 842 retains a dual model, requiring leases to be classified as either operating or finance. Operating leases will result in straight-line expense, while finance leases will result in a front-loaded expense pattern, similar to prior capital leases. Classification of operating and finance leases will be based on criteria that are largely similar to those applied in prior lease guidance but without the explicit thresholds. The new guidance is effective for fiscal years beginning after December 2018. The new guidance must be adopted using a modified retrospective transition method and provides for certain practical expedients. Transition method options include application of the new guidance at the beginning of the earliest comparative period presented or at the adoption date, with a cumulative-effect adjustment to retained earnings in the period of adoption. The Company evaluated its current lease contracts and applied the package of practical expedients allowing entities to not reassess (i) whether any expired or existing contracts are or contain leases, (ii) the lease classification for any expired or existing leases and (iii) initial direct costs for any existing leases. The Company recognized approximately $38.0 million of lease liabilities in its Consolidated Balance Sheet at January 1, 2019 for railcar, wind farm land and office space leases.

In January 2018, the FASB issued ASU 2018-01, "Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842," which is an amendment to ASU 2016-02. Land easements (also commonly referred to as rights of way) represent the right to use, access or cross another entity's land for a specified purpose. This new guidance permits an entity to elect a transitional practical expedient, to be applied consistently, to not evaluate land easements under Topic 842 that exist or expired before the entity's adoption of Topic 842 and that were not previously accounted for as leases under ASC 840, "Leases." Once Topic 842 is adopted, an entity is required to apply Topic 842 prospectively to all new (or modified) land easements to determine whether the arrangement should be accounted for as a lease. ASU 2018-01 is effective for fiscal years beginning after December 2018. The Company elected this practical expedient during its adoption of Topic 842 and did not evaluate existing easement contracts under Topic 842, if these contracts had not previously been accounted for under Topic 840.

In July 2018, the FASB issued ASU 2018-11, "Leases (Topic 842): Targeted Improvements," which provides the following additional amendments to ASU 2016-02: (i) entities can elect to initially apply ASU 2016-02 at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption and (ii) lessors can elect a practical expedient, by class of underlying asset, to account for nonlease components and the associated lease component as a single component, if the nonlease component otherwise would be accounted for under Topic 606 and certain conditions, as described in ASU 2018-11, are met. If an entity elects the additional (and optional) transition method, the entity will provide the required Topic 840 disclosures for all periods that continue to be reported under Topic 840. ASU 2018-11 is effective for fiscal years beginning after December 2018. The Company elected the transition method provided by the guidance allowing for initial application at January 1, 2019.

Issued Accounting Standards Not Yet Adopted

Fair Value Measurement Disclosure Framework. In August 2018, the FASB issued ASU 2018-13, "Fair Value Measurement (Topic 820): Disclosure Framework - Changes to the Disclosure Requirements for Fair Value Measurement." The new guidance removes, adds or modifies disclosure requirements that impact all levels of the fair value hierarchy, as well as investments measured using the net asset value practical expedient. ASU 2018-13 is effective for fiscal years beginning after December 2019 and is required to be applied both retrospectively and prospectively, depending on the specific disclosure change. Early adoption is permitted. The Company does not believe this ASU will have a significant impact on its financial statement disclosures.

Defined Benefit Plans Disclosure Framework. In August 2018, the FASB issued ASU 2018-14, "Compensation - Retirement Benefits - Defined Benefit Plans - General (Subtopic 715-20): Disclosure Framework - Changes to the Disclosure Requirements for Defined Benefit Plans." The new guidance removes, adds or clarifies disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. ASU 2018-14 is effective for fiscal years ending after December 2020 and is required to be applied on a retrospective basis. Early adoption is permitted. The Company does not believe this ASU will have a significant impact on its financial statement disclosures.

Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract. In August 2018, the FASB issued ASU 2018-15, "Intangibles - Goodwill and Other - Internal-Use Software (Subtopic 350-40): Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract." The new guidance aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. ASU 2018-15 is effective for fiscal years beginning after December 2019 and can be applied either retrospectively or prospectively to all implementation costs incurred after the date of adoption. Early adoption is permitted. The Company is currently evaluating the impact of this ASU on its Consolidated Financial Statements.

3. Revenue Recognition

The following table disaggregates the Company's revenues from contracts with customers by customer classification. The Company's operating revenues disaggregated by customer classification can be found in "OG&E (Electric Utility) Results of Operations" in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

(In millions)		**Year Ended December 31, 2018**
Residential	$	877.8
Commercial		578.0
Industrial		191.1
Oilfield		150.2
Public authorities and street light		197.4
System sales revenues		1,994.5
Provision for rate refund		(6.0)
Integrated market		48.7
Transmission		147.4
Other		27.1
Revenues from contracts with customers	$	2,211.7

4. Investment in Unconsolidated Affiliate and Related Party Transactions

In 2013, the Company, CenterPoint and the ArcLight group formed Enable as a private limited partnership, and 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 recorded the contribution at historical cost. 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 was allocated to the assets acquired and liabilities assumed based on their fair value. Enogex Holdings' assets, liabilities and equity were accordingly adjusted to estimated fair value, resulting in an increase to Enable's equity of $2.2 billion. Since the contribution of Enogex LLC to Enable was recorded 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.

At December 31, 2018, the Company owned 111.0 million common units, or 25.6 percent, of Enable's outstanding common units. On December 31, 2018, Enable's common unit price closed at $13.53. The Company recorded equity in earnings of unconsolidated affiliates of $152.8 million, $131.2 million and $101.8 million for the years ended December 31, 2018, 2017 and 2016, respectively. Equity in earnings of unconsolidated affiliates includes the Company's share of Enable earnings adjusted for the amortization of the basis difference of the Company's original investment in Enogex LLC and its underlying equity in the net assets of Enable and is also adjusted for the elimination of the Enogex Holdings fair value adjustments. The basis difference is being amortized, beginning in 2013, 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.

Summarized unaudited financial information for 100 percent of Enable is presented below as of December 31, 2018 and 2017 and for the years ended December 31, 2018, 2017 and 2016.

Balance Sheet	**December 31,**	
(In millions)	**2018**	2017
Current assets	**$ 449**	$ 416
Non-current assets	**$ 11,995**	$ 11,177
Current liabilities	**$ 1,615**	$ 1,279
Non-current liabilities	**$ 3,211**	$ 2,660

Income Statement	**Year Ended December 31,**		
(In millions)	**2018**	2017	2016
Total revenues	**$ 3,431**	$ 2,803	$ 2,272
Cost of natural gas and NGLs	**$ 1,819**	$ 1,381	$ 1,017
Operating income	**$ 648**	$ 528	$ 385
Net income	**$ 485**	$ 400	$ 290

The following table reconciles OGE Energy's equity in earnings of its unconsolidated affiliates for the years ended December 31, 2018, 2017 and 2016, respectively.

	Year Ended December 31,		
(In millions)	**2018**	2017	2016
Enable net income	**$ 485.3**	$ 400.3	$ 289.5
Distributions senior to limited partners	**—**	—	(9.1)
Differences due to timing of OGE Energy and Enable accounting close	**—**	—	(12.2)
Enable net income used to calculate OGE Energy's equity in earnings	**$ 485.3**	$ 400.3	$ 268.2
OGE Energy's percent ownership at period end	**25.6%**	25.7%	25.7%
OGE Energy's portion of Enable net income	**$ 124.4**	$ 102.7	$ 70.7
Impairments recognized by Enable associated with OGE Energy's basis difference	**—**	—	2.6
OGE Energy's share of Enable net income	**124.4**	102.7	73.3
Amortization of basis difference	**11.2**	11.3	11.6
Elimination of Enable fair value step up	**17.2**	17.2	16.9
Equity in earnings of unconsolidated affiliates	**$ 152.8**	$ 131.2	$ 101.8

The difference between OGE Energy's investment in Enable and its underlying equity in the net assets of Enable was $680.3 million as of December 31, 2018. The following table reconciles the basis difference in Enable from December 31, 2017 to December 31, 2018.

(In millions)	
Basis difference at December 31, 2017	$ 714.2
Change in Enable basis difference	(5.5)
Amortization of basis difference	(11.2)
Elimination of Enable fair value step up	(17.2)
Basis difference at December 31, 2018	$ 680.3

On February 8, 2019, Enable announced a quarterly dividend distribution of $0.31800 per unit on its outstanding common units, which is unchanged from the previous quarter. 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. The Company 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.

Distributions received from Enable were $141.2 million, $141.2 million and $141.2 million during the years ended December 31, 2018, 2017 and 2016, respectively.

Related Party Transactions - the Company and Enable

The Company and Enable are currently parties to several agreements whereby the Company provides specified support services to Enable, such as certain information technology, payroll and benefits administration. Under these agreements, the Company charged operating costs to Enable of $0.6 million, $2.3 million and $4.7 million for December 31, 2018, 2017 and 2016, 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.

Pursuant to a seconding agreement, the Company provides seconded employees to Enable to support Enable's operations. As of December 31, 2018, 90 employees that participate in the Company's defined benefit and retirement plans are seconded to Enable. The Company billed Enable for reimbursement of $27.5 million, $29.5 million and $28.7 million in 2018, 2017 and 2016, respectively, under the Transitional Seconding Agreement for employment costs. If the seconding agreement was terminated, and those employees were no longer employed by the Company, and lump sum payments were made to those employees, the Company would recognize a settlement or curtailment of the pension/retiree health care charges, which would increase expense at the Company by $20.4 million. Settlement and curtailment charges associated with the Enable seconded employees are not reimbursable to the Company by Enable. The seconding agreement can be terminated by mutual agreement of the Company and Enable or solely by the Company upon 120 day notice.

The Company had accounts receivable from Enable for amounts billed for transitional services, including the cost of seconded employees, of $1.7 million and $2.0 million as of December 31, 2018 and 2017, respectively, which are included in Accounts Receivable on the Company's Consolidated Balance Sheets.

Related Party Transactions - OG&E and Enable

Enable provides gas transportation services to OG&E pursuant to an agreement that expires in April 2019. In October 2018, OG&E and Enable agreed to a new contract that will be effective as of April 2019 for a five year period ending May 2024. 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. In 2016, OG&E entered into an additional gas transportation services contract with Enable that became effective in December 2018 related to the project to convert Muskogee Units 4 and 5 from coal to natural gas. The following table summarizes related party transactions between OG&E and Enable during the years ended December 31, 2018, 2017 and 2016.

	Year Ended December 31,		
(In millions)	**2018**	2017	2016
Operating revenues:			
Electricity to power electric compression assets	**$ 16.3**	$ 14.0	$ 11.5
Cost of sales:			
Natural gas transportation services	**$ 37.9**	$ 35.0	$ 35.0
Natural gas (sales) purchases	**$ (3.2)**	$ (2.1)	$ 11.2

5. 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, 2018 and 2017. 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 whose fair value is 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 following table summarizes the fair value and carrying amount of the Company's financial instruments at December 31, 2018 and 2017.

	2018		2017	
December 31 *(In millions)*	**Carrying Amount**	**Fair Value**	Carrying Amount	Fair Value
Long-term Debt (including Long-term Debt due within one year):				
Senior Notes	**$ 3,001.9**	**$ 3,178.2**	$ 2,854.3	$ 3,242.8
OG&E Industrial Authority Bonds	**$ 135.4**	**$ 135.4**	$ 135.4	$ 135.4
Tinker Debt	**$ 9.6**	**$ 8.7**	$ 9.7	$ 9.8

6. Stock-Based Compensation

In 2013, the Company adopted, and its shareholders approved, the Stock Incentive 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, 2018, 2017 and 2016 related to the Company's performance units and restricted stock.

Year Ended December 31 *(In millions)*	**2018**	2017	2016
Performance units:			
Total shareholder return	**$ 8.2**	$ 7.6	$ 4.5
Earnings per share	**5.1**	1.4	—
Total performance units	**13.3**	9.0	4.5
Restricted stock	**0.1**	0.1	0.1
Total compensation expense	**$ 13.4**	$ 9.1	$ 4.6
Income tax benefit	**$ 3.4**	$ 3.5	$ 1.8

The Company has issued new shares to satisfy restricted stock grants and payouts of earned performance units. In 2018, 2017 and 2016, there were 26,211 shares, 2,298 shares and 2,100 shares, respectively, of new common stock issued pursuant to the Company's Stock Incentive Plan related to restricted stock grants and payouts of earned performance units.

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 primarily 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 Company estimates expected forfeitures in accounting for performance unit compensation expense.

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 primarily 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 primarily 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 Sheets. If there is no or only a partial payout for the performance units at the end of the award cycle, the unearned performance units are cancelled. Payout requires approval of the Compensation Committee of the Company's Board of Directors. Payouts, if any, are all made in common stock and are considered made when the payout is approved by the Compensation Committee.

Performance Units – Total Shareholder Return

The fair value of the performance units based on total shareholder return was estimated on the grant date using a lattice-based valuation model that factors in information, including the expected dividend yield, expected price volatility, risk-free interest rate and the probable outcome of the market condition, over the expected life of the performance units. Compensation expense for the performance units is a fixed amount determined at the grant date fair value and is recognized over the primarily three-year award cycle regardless of whether performance units are awarded at the end of the award cycle. Dividends are accrued on a quarterly basis pending achievement of payout criteria and are 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.

	2018	2017	2016
Number of units granted	**261,916**	260,570	284,211
Fair value of units granted	**$ 36.86**	$ 41.77	$ 20.97
Expected dividend yield	**3.6%**	3.8%	3.5%
Expected price volatility	**19.0%**	19.9%	19.8%
Risk-free interest rate	**2.38%**	1.44%	0.88%
Expected life of units (in years)	**2.86**	2.80	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.

	2018	2017	2016
Number of units granted	**87,308**	86,857	94,735
Fair value of units granted	**$ 31.03**	$ 34.83	$ 26.64

Restricted Stock

Under the Stock Incentive Plan, 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 primarily 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 primarily 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 will only be paid on restricted stock awards that vest; therefore, only the present value of dividends expected to vest are included in the fair value calculations. The expected life of the restricted stock is based on the non-vested period since inception of the primarily 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.

	2018	2017	2016
Shares of restricted stock granted	**826**	3,145	1,881
Fair value of restricted stock granted	**$ 36.28**	$ 34.96	$ 29.27

A summary of the activity for the Company's performance units and restricted stock at December 31, 2018 and changes in 2018 are shown in the following table.

	Performance Units				Restricted Stock	
	Total Shareholder Return		Earnings Per Share			
(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 12/31/17	724,551		241,518		4,242	
Granted	**261,916 (A)**		**87,308 (A)**		**826**	
Converted	**(201,431) (B)**	**$ —**	**(67,148) (B)**	**$ 1.2**	**N/A**	
Vested	**N/A**		**N/A**		**(2,357)**	**$ 0.1**
Forfeited	**(29,556)**		**(9,853)**		**—**	
Units/shares outstanding at 12/31/18	**755,480**	**$ 53.2**	**251,825**	**$ 14.1**	**2,711**	**$ 0.1**
Units/shares fully vested at 12/31/18	**274,078**	**$ 19.8**	**91,356**	**$ 7.2**		

(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 zero percent to 200 percent of the target.

(B) These amounts represent performance units that vested at December 31, 2017 which were settled in February 2018.

A summary of the activity for the Company's non-vested performance units and restricted stock at December 31, 2018 and changes in 2018 are shown in the following table.

	Performance Units				Restricted Stock	
	Total Shareholder Return		Earnings Per Share			
	Number of Units	Weighted-Average Grant Date Fair Value	Number of Units	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Units/shares non-vested at 12/31/17	523,120	$ 30.96	174,370	$ 30.58	4,242	$ 33.58
Granted	**261,916 (A)**	**$ 36.86**	**87,308 (A)**	**$ 31.03**	**826**	**$ 36.28**
Vested	**(274,078)**	**$ 21.69**	**(91,356)**	**$ 26.93**	**(2,357)**	**$ 32.84**
Forfeited	**(29,556)**	**$ 35.55**	**(9,853)**	**$ 31.94**	**—**	**$ —**
Units/shares non-vested at 12/31/18	**481,402**	**$ 39.17**	**160,469**	**$ 32.82**	**2,711**	**$ 35.00**
Units/shares expected to vest	**464,027 (B)**		**154,678 (B)**		**2,711**	

(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 zero percent to 200 percent of the target.

(B) The intrinsic value of the performance units based on total shareholder return and earnings per share is $32.0 million and $6.8 million, respectively.

Fair Value of Vested Performance Units and Restricted Stock

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

Year Ended December 31 *(In millions)*		**2018**		2017		2016
Performance units:						
Total shareholder return	**$**	**5.9**	$	6.3	$	6.4
Earnings per share	**$**	**4.9**	$	1.2	$	—
Restricted stock	**$**	**0.1**	$	0.1	$	0.1

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, 2018		**Unrecognized Compensation Cost** *(In millions)*	**Weighted Average to be Recognized** *(In years)*
Performance units:			
Total shareholder return	**$**	**9.0**	**1.65**
Earnings per share		**2.5**	**1.66**
Total performance units		**11.5**	
Restricted stock		**0.1**	**1.94**
Total unrecognized compensation cost	**$**	**11.6**	

7. Supplemental Cash Flow Information

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

Year Ended December 31 *(In millions)*		**2018**		2017		2016
NON-CASH INVESTING AND FINANCING ACTIVITIES						
Power plant long-term service agreement	**$**	**(9.2)**	$	(2.6)	$	39.5
SUPPLEMENTAL CASH FLOW INFORMATION						
Cash paid during the period for:						
Interest (net of interest capitalized) (A)	**$**	**153.8**	$	139.6	$	141.9
Income taxes (net of income tax refunds)	**$**	**2.8**	$	(16.0)	$	(5.9)

(A) Net of interest capitalized of $11.7 million, $18.0 million and $7.5 million in 2018, 2017 and 2016, respectively.

8. Income Taxes

2017 Tax Act

In December 2017, the 2017 Tax Act was signed into law, reducing the corporate federal tax rate from 35 percent to 21 percent for tax years beginning in 2018. ASC 740, "Income Taxes," requires deferred tax assets and liabilities to be measured at the enacted tax rate expected to apply when temporary differences are to be realized and settled. Entities subject to ASC 980, "Accounting for Regulated Entities," such as OG&E, are required to recognize a regulatory liability for the decrease in taxes payable for the change in tax rates that are expected to be returned to customers through future rates and to recognize a regulatory asset for the increase in taxes receivable for the change in tax rates that are expected to be recovered from customers through future rates. At December 31, 2017, as a result of remeasuring existing deferred taxes at the lower 21 percent tax rate, the Company reduced net deferred income tax liabilities and increased regulatory liabilities. As of December 31, 2018, the Company's regulatory liability for income taxes refundable to customers, net was $1.022 billion, as a result of the change in the corporate federal tax rate.

As a result of the 2017 Tax Act, in early January 2018: (i) the OCC ordered OG&E to record a reserve, including accrued interest, to reflect the reduced federal corporate tax rate, among other tax implications, on an interim basis, subject to refund until utility rates were adjusted to reflect the federal tax savings; (ii) the APSC ordered OG&E to book regulatory liabilities to record the current and deferred impacts of the 2017 Tax Act until the resulting benefits, including carrying charges, are returned to customers; and (iii) through a Section 206 filing with the FERC, modifications were requested to be made to OG&E's transmission formula rates to reflect the impacts of the 2017 Tax Act. Further discussion regarding OG&E's response to OCC, APSC and FERC proceedings, including reserves to revenue for each jurisdiction, can be found in Note 15 under "Oklahoma Rate Review Filing - January 2018," "APSC Order - 2017 Tax Act," "FERC - Request for Waiver" and "FERC - Section 206 Filing." As of December 31, 2018, the total recorded reserve was $15.4 million, which is included in Other Current Liabilities in the Company's Consolidated Balance Sheets.

Staff Accounting Bulletin No. 118

Staff Accounting Bulletin No. 118 addresses the application of U.S. GAAP in situations when a registrant does not have the necessary information available, prepared or analyzed (including computations) in reasonable detail to complete the accounting for certain income tax effects of the 2017 Tax Act. The Company recognized the provisional tax impacts related to the revaluation of deferred tax assets and liabilities as of December 31, 2017, as the Company had not completed its accounting for income tax effects of the 2017 Tax Act. As of December 31, 2018, the Company has completed its accounting for the enactment-date income tax effects of the 2017 Tax Act. Upon further analysis of certain aspects of the 2017 Tax Act and refinement of the final calculations during the 12 months ended December 31, 2018, the Company adjusted its provisional amount by an increase to tax expense of $2.1 million and increased regulatory liabilities by $7.4 million.

Income Tax Expense (Benefit)

The items comprising income tax expense (benefit) are as follows:

Year Ended December 31 *(In millions)*	**2018**	2017	2016
Provision (benefit) for current income taxes:			
Federal	**$ (1.9)**	$ 4.9	$ —
State	**(4.4)**	(4.2)	(5.7)
Total provision (benefit) for current income taxes	**(6.3)**	0.7	(5.7)
Provision (benefit) for deferred income taxes, net:			
Federal	**74.7**	(75.9)	126.0
State	**3.7**	26.0	28.0
Total provision (benefit) for deferred income taxes, net	**78.4**	(49.9)	154.0
Deferred federal investment tax credits, net	**0.1**	(0.1)	(0.2)
Total income tax expense (benefit)	**$ 72.2**	$ (49.3)	$ 148.1

The Company files consolidated income tax returns in the U.S. federal jurisdiction and various state jurisdictions. With few exceptions, the Company is no longer subject to U.S. federal tax examinations by tax authorities for years prior to 2015 or state and local tax examinations by tax authorities for years prior to 2014. 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 and earns Oklahoma state tax credits associated with its investments in electric generating facilities which 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	**2018**	2017	2016
Statutory federal tax rate	**21.0 %**	35.0 %	35.0 %
Federal deferred tax revaluation	**0.4**	(41.2)	—
Other	**0.4**	(0.1)	0.1
State income taxes, net of federal income tax benefit	**0.4**	2.0	1.9
Executive compensation limitation	**0.2**	—	—
Federal renewable energy credit (A)	**(5.1)**	(4.8)	(6.8)
Amortization of net unfunded deferred taxes	**(2.1)**	0.7	0.7
Remeasurement of state deferred tax liabilities	**(0.4)**	0.4	0.9
401(k) dividends	**(0.3)**	(0.5)	(0.6)
Federal investment tax credits, net	**—**	(0.1)	(0.8)
Uncertain tax positions	**—**	—	0.1
Effective income tax rate	**14.5 %**	(8.6)%	30.5 %

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

The deferred tax provisions are recognized as costs in the ratemaking process by the commissions having jurisdiction over the rates charged by OG&E. The components of Deferred Income Taxes at December 31, 2018 and 2017 were as follows:

December 31 *(In millions)*	**2018**	2017
Deferred income tax liabilities, net:		
Accelerated depreciation and other property related differences	**$ 1,605.3**	$ 1,449.6
Investment in Enable	**469.9**	441.7
Regulatory assets	**17.4**	18.9
Company Pension Plan	**7.6**	11.5
Bond redemption-unamortized costs	**2.4**	2.6
Derivative instruments	**1.7**	1.6
Other	**1.1**	(0.9)
Income taxes recoverable from customers, net	**(239.6)**	(244.3)
Federal tax credits	**(237.8)**	(218.5)
State tax credits	**(156.0)**	(141.7)
Regulatory liabilities	**(78.8)**	(16.8)
Postretirement medical and life insurance benefits	**(23.6)**	(25.2)
Asset retirement obligations	**(21.5)**	(19.2)
Net operating losses	**(20.2)**	(21.1)
Accrued liabilities	**(12.5)**	(7.4)
Accrued vacation	**(2.3)**	(2.1)
Deferred federal investment tax credits	**(1.8)**	(0.5)
Uncollectible accounts	**(0.4)**	(0.4)
Total deferred income tax liabilities, net	**$ 1,310.9**	$ 1,227.8

As of December 31, 2018, the Company has classified $16.4 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, 2018, 2017 and 2016.

(In millions)	**2018**	2017	2016
Balance at January 1	**$ 20.7**	$ 20.7	$ 20.2
Tax positions related to current year:			
Additions	**—**	—	0.5
Balance at December 31	**$ 20.7**	$ 20.7	$ 20.7

As of December 31, 2018, 2017 and 2016, there were $16.4 million, $16.4 million and $13.5 million of unrecognized tax benefits that, if recognized, would affect the annual effective tax rate.

Where applicable, the Company classifies income tax-related interest and penalties as interest expense and other expense, respectively. During the year ended December 31, 2018, there were no income tax-related interest or penalties recorded with regard to uncertain tax positions.

The Company sustained federal and state tax operating losses through 2012 caused primarily by bonus depreciation and other book versus tax temporary differences. As a result, the Company had accrued federal and state income tax benefits carrying into 2017, when the remaining federal net operating loss was utilized. State operating losses are being carried forward for utilization in future years. In addition to the tax 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 remaining losses and credits before they begin to expire. The following table summarizes these carry forwards:

(In millions)	**Carry Forward Amount**	**Deferred Tax Asset**	**Earliest Expiration Date**
State operating loss	$ 451.8	$ 20.2	2030
Federal tax credits	$ 237.8	$ 237.8	2032
State tax credits:			
Oklahoma investment tax credits	$ 161.6	$ 127.7	N/A
Oklahoma capital investment board credits	$ 8.9	$ 8.9	N/A
Oklahoma zero emission tax credits	$ 24.1	$ 19.4	2020

N/A - not applicable

9. Common Equity

Automatic Dividend Reinvestment and Stock Purchase Plan

The Company issued no shares of common stock under its Automatic Dividend Reinvestment and Stock Purchase Plan in 2018. The Company may, from time to time, issue shares under its Automatic Dividend Reinvestment and Stock Purchase Plan or purchase shares traded on the open market. At December 31, 2018, 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 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 except per share data)	**2018**	2017	2016
Net income	**$ 425.5**	$ 619.0	$ 338.2
Average common shares outstanding:			
Basic average common shares outstanding	**199.7**	199.7	199.7
Effect of dilutive securities:			
Contingently issuable shares (performance and restricted stock units)	**0.8**	0.3	0.2
Diluted average common shares outstanding	**200.5**	200.0	199.9
Basic earnings per average common share	**$ 2.13**	$ 3.10	$ 1.69
Diluted earnings per average common share	**$ 2.12**	$ 3.10	$ 1.69
Anti-dilutive shares excluded from earnings per share calculation	**—**	—	—

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. 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. 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.

The Company utilizes 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 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 $580.5 million of the Company's retained earnings from being paid out in dividends. Accordingly, approximately $2.3 billion of the Company's retained earnings as of December 31, 2018 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 $674.9 million of OG&E's retained earnings from being paid out in dividends. Accordingly, approximately $1.9 billion of OG&E's retained earnings as of December 31, 2018 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, 2018, 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)
1.01%	-	2.00%	Garfield Industrial Authority, January 1, 2025	$ 47.0
1.01%	-	1.83%	Muskogee Industrial Authority, January 1, 2025	32.4
1.03%	-	1.86%	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 $250.1 million, $0.1 million, $0.1 million, $0.1 million and $0.1 million in 2019, 2020, 2021, 2022 and 2023, 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 and unamortized premium and discount on long-term debt are classified as Long-Term Debt in the Consolidated Balance Sheets and are being amortized over the life of the respective debt.

Issuance of Long-Term Debt

In August 2018, OG&E issued $400.0 million of 3.80 percent senior notes due August 15, 2028. The proceeds from the issuance were added to OG&E's general funds to be used for general corporate purposes, including to fund the payment of OG&E's $250.0 million of 6.35 percent senior notes that matured on September 1, 2018, to repay short-term debt and to fund ongoing capital expenditures and working capital.

11. Short-Term Debt and Credit Facilities

The Company and OG&E's credit facilities each have a financial covenant requiring that the respective borrower maintain a maximum debt to capitalization ratio of 65 percent, as defined in each such facility. The Company and OG&E's facilities each also contain covenants which restrict the respective borrower and certain of its subsidiaries in respect of, among other things, mergers and consolidations, sales of all or substantially all assets, incurrence of liens and transactions with affiliates. The Company and OG&E's facilities are each subject to acceleration upon the occurrence of any default, including, among others, payment defaults on such facilities, breach of representations, warranties and covenants, acceleration of indebtedness (other than intercompany and non-recourse indebtedness) of $100.0 million or more in the aggregate, change of control (as defined in each such facility), nonpayment of uninsured judgments in excess of $100.0 million and the occurrence of certain Employee Retirement Income Security Act and bankruptcy events, subject where applicable to specified cure periods.

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, 2018, the Company had no short-term debt outstanding compared to $168.4 million at December 31, 2017. The following table provides information regarding the Company's revolving credit agreements at December 31, 2018.

Entity	Aggregate Commitment	Amount Outstanding (A)	Weighted-Average Interest Rate	Expiration	
	(In millions)				
OGE Energy (B)	$ 450.0	$ —	—% (D)	March 8, 2023	(E)
OG&E (C)	450.0	0.3	1.05% (D)	March 8, 2023	(E)
Total	$ 900.0	$ 0.3	1.05%		

(A) Includes direct borrowings under the revolving credit agreements, commercial paper borrowings and letters of credit at December 31, 2018.
(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 March 2017, the Company and OG&E entered into unsecured five-year revolving credit agreements totaling $900.0 million ($450.0 million for the Company and $450.0 million for OG&E). Each of the facilities contained an option, which could be exercised up to two times, to extend the term of the respective facility for an additional year. Effective March 9, 2018, the Company and OG&E utilized one of those extensions to extend the maturity of their respective credit facility from March 8, 2022 to March 8, 2023.

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, 2019 and ending December 31, 2020.

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. The Company made a $15.0 million and $20.0 million contribution to its Pension Plan in 2018 and 2017, respectively. The Company has not determined whether it will need to make any contributions to the Pension Plan in 2019. Any contribution to the Pension Plan during 2019 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.

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 2018 and 2017, the Company experienced an increase in both the number of employees electing to retire and the amount of lump sum payments paid to such employees upon retirement. As a result, the Company recorded pension plan settlement charges of $26.1 million during 2018 and $15.3 million during 2017. The pension settlement charges 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. During 2016, the Company experienced a settlement of its Supplemental Executive

Retirement Plan and its non-qualified Restoration of Retirement Income Plan. As a result, the Company recorded pension settlement charges of $8.6 million during 2016.

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 2018 and 2017. 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, 2018 was $561.9 million and $7.8 million, respectively. The accumulated postretirement benefit obligation for the Pension Plan and the Restoration of Retirement Income Plan at December 31, 2017 was $626.9 million and $7.5 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 included in the following table.

	Pension Plan		**Restoration of Retirement Income Plan**		**Postretirement Benefit Plans**	
December 31 *(In millions)*	**2018**	2017	**2018**	2017	**2018**	2017
Change in benefit obligation						
Beginning obligations	**$ 687.5**	$ 672.2	**$ 8.1**	$ 7.0	**$ 149.4**	$ 215.9
Service cost	**14.9**	15.5	**0.4**	0.3	**0.3**	0.6
Interest cost	**23.8**	26.2	**0.3**	0.3	**5.4**	7.2
Plan settlements	**(73.7)**	(50.2)	**(2.0)**	—	**—**	(28.1)
Plan amendments	**—**	—	**—**	—	**—**	(39.6)
Participants' contributions	**—**	—	**—**	—	**3.8**	3.5
Actuarial losses (gains)	**(22.0)**	38.6	**2.8**	0.7	**(9.6)**	5.6
Benefits paid	**(14.6)**	(14.8)	**—**	(0.2)	**(13.5)**	(15.7)
Ending obligations	**$ 615.9**	$ 687.5	**$ 9.6**	$ 8.1	**$ 135.8**	$ 149.4
Change in plans' assets						
Beginning fair value	**$ 635.3**	$ 595.9	**$ —**	$ —	**$ 50.2**	$ 53.1
Actual return on plans' assets	**(39.2)**	84.4	**—**	—	**(0.6)**	2.8
Employer contributions	**15.0**	20.0	**2.0**	0.2	**5.4**	34.6
Plan settlements	**(73.7)**	(50.2)	**(2.0)**	—	**—**	(28.1)
Participants' contributions	**—**	—	**—**	—	**3.8**	3.5
Benefits paid	**(14.6)**	(14.8)	**—**	(0.2)	**(13.5)**	(15.7)
Ending fair value	**$ 522.8**	$ 635.3	**$ —**	$ —	**$ 45.3**	$ 50.2
Funded status at end of year	**$ (93.1)**	$ (52.2)	**$ (9.6)**	$ (8.1)	**$ (90.5)**	$ (99.2)

Net Periodic Benefit Cost

The Company adopted ASU 2017-07 in the first quarter of 2018 and, as a result, presents the service cost component of net benefit cost in operating income and the other components of net benefit cost as non-operating within its Consolidated Statements of Income. Further, as required by ASU 2017-07, the Company adjusted prior year income statement presentation of the net benefit cost components, which were previously presented in total within Other Operation and Maintenance in the Company's Consolidated Statements of Income. The Company elected the practical expedient allowed by ASU 2017-07 to utilize amounts disclosed in the Company's retirement plans and postretirement benefit plans note for the prior comparative period as the estimation basis for applying the retrospective presentation requirements.

The following table presents the net periodic benefit cost components, before consideration of capitalized amounts, of the Company's Pension Plan, Restoration of Retirement Income Plan and postretirement benefit plans that are included in the Consolidated Financial Statements. Service cost is presented within Other Operation and Maintenance, and interest cost, expected return on plan assets, amortization of net loss, amortization of unrecognized prior service cost and settlement cost are presented within Other Net Periodic Benefit Expense in the Company's Consolidated Statements of Income. OG&E recovers specific amounts of pension and postretirement medical costs in rates approved in its Oklahoma rate reviews. 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 review as a regulatory asset or regulatory liability. These amounts have been recorded in the Pension tracker in the regulatory assets and liabilities table in Note 1 and within Other Net Periodic Benefit Expense in the Company's Consolidated Statements of Income.

	Pension Plan			**Restoration of Retirement Income Plan**			**Postretirement Benefit Plans**		
Year Ended December 31 *(In millions)*	**2018**	2017	2016	**2018**	2017	2016	**2018**	2017	2016
Service cost	**$ 14.9**	$ 15.5	$ 15.8	**$ 0.4**	$ 0.3	$ 0.3	**$ 0.3**	$ 0.6	$ 0.8
Interest cost	**23.8**	26.2	25.5	**0.3**	0.3	0.4	**5.4**	7.2	9.5
Expected return on plan assets	**(44.1)**	(42.6)	(41.5)	**—**	—	—	**(2.0)**	(2.2)	(2.3)
Amortization of net loss	**16.2**	17.4	16.5	**0.7**	0.4	0.7	**3.8**	2.0	2.6
Amortization of unrecognized prior service cost (A)	**—**	(0.1)	(0.1)	**0.1**	0.1	0.1	**(8.4)**	(3.5)	(8.8)
Settlement cost	**25.1**	15.3	—	**1.0**	—	8.6	**—**	0.6	—
Total net periodic benefit cost	**35.9**	31.7	16.2	**2.5**	1.1	10.1	**(0.9)**	4.7	1.8
Less: Amount paid by unconsolidated affiliates	**2.5**	4.3	5.1	**0.1**	—	0.3	**(0.5)**	0.3	0.2
Net periodic benefit cost (B)	**$ 33.4**	$ 27.4	$ 11.1	**$ 2.4**	$ 1.1	$ 9.8	**$ (0.4)**	$ 4.4	$ 1.6

(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 $35.4 million, $32.9 million and $22.5 million of net periodic benefit cost recognized in 2018, 2017 and 2016, respectively, OG&E recognized the following:

- a change in pension expense in 2018, 2017 and 2016 of $(14.1) million, $(2.3) million and $9.9 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 2018, 2017 and 2016 of $4.4 million, $6.2 million and $7.9 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); and
- a deferral of pension expense in 2018, 2017 and 2016 of $2.1 million, $1.1 million and $0.1 million related to the Arkansas jurisdictional portion of the pension settlement charge of $26.1 million, $15.3 million and $8.6 million, respectively, which are included in the Arkansas deferred pension expense regulatory asset (see Note 1).

As required by ASU 2017-07, the Company only capitalizes the service cost component of net benefit cost, beginning in the first quarter of 2018. Prior year capitalized amounts were not adjusted, as this change was implemented on a prospective basis.

(In millions)	**2018**	2017	2016
Capitalized portion of net periodic pension benefit cost	**$ 3.8**	$ 4.4	$ 4.0
Capitalized portion of net periodic postretirement benefit cost	**$ 0.2**	$ 1.2	$ 0.8

Rate Assumptions

Year Ended December 31	Pension Plan and Restoration of Retirement Income Plan			Postretirement Benefit Plans		
	2018	2017	2016	**2018**	2017	2016
Assumptions to determine benefit obligations:						
Discount rate	**4.20%**	3.60%	4.00%	**4.30%**	3.70%	4.20%
Rate of compensation increase	**4.20%**	4.20%	4.20%	**N/A**	N/A	4.20%
Assumptions to determine net periodic benefit cost:						
Discount rate	**3.73%**	4.00%	4.00%	**3.70%**	4.20%	4.25%
Expected return on plan assets	**7.50%**	7.50%	7.50%	**4.00%**	4.00%	4.00%
Rate of compensation increase	**4.20%**	4.20%	4.20%	**N/A**	4.20%	4.20%

N/A - not applicable

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 discount rate used to determine net benefit cost for the current year is the same discount rate used to determine the benefit obligation as of the previous year's balance sheet date.

The overall expected rate of return on plan assets assumption was 7.50 percent in both 2018 and 2017, 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 7.25 percent in 2019 with the rates trending downward to 4.50 percent by 2030. 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)*	**2018**	2017	2016
Effect on aggregate of the service and interest cost components	**$ —**	$ —	$ —
Effect on accumulated postretirement benefit obligations	**$ 0.1**	$ 0.1	$ 0.2

ONE-PERCENTAGE POINT DECREASE

Year Ended December 31 *(In millions)*	**2018**	2017	2016
Effect on aggregate of the service and interest cost components	**$ —**	$ —	$ —
Effect on accumulated postretirement benefit obligations	**$ 0.3**	$ 0.3	$ 0.7

Pension 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 Large Cap Equity	40%	35%	60%
Domestic Mid-Cap Equity	15%	5%	25%
Domestic Small-Cap Equity	25%	5%	30%
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)
Active Duration Fixed Income	Bloomberg Barclays Aggregate
Long Duration Fixed Income	Duration blended Barclays Long Government/Credit & Barclays Universal
Equity Index	Standard & Poor's 500 Index
Mid-Cap Equity	Russell Midcap Index
	Russell Midcap Value Index
Small-Cap Equity	Russell 2000 Index
	Russell 2000 Value Index
International Equity	Morgan Stanley Capital International ACWI ex-U.S.

The fixed income managers are expected to use discretion over the asset mix of the trust assets in their efforts to maximize risk-adjusted performance. Exposure to any single issuer, other than the U.S. government, its agencies or its instrumentalities (which have no limits), is limited to five percent of the fixed income portfolio as measured by market value. At least 75 percent of the invested assets must possess an investment-grade rating at or above Baa3 or BBB- by Moody's Investors Service, S&P's Global Ratings 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 15 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-U.S. Index is the benchmark for comparative performance purposes. The Morgan Stanley Capital International All Country World ex-U.S. Index is a market value weighted index designed to measure the combined equity market performance of developed and emerging markets countries, excluding the U.S. All of the equities which are purchased for the international portfolio are thoroughly researched. 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 five percent can be invested in any one stock at the time of purchase and no more than 10 percent 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.

Pension Plan Investments

The following tables summarize the Pension Plan's investments that are measured at fair value on a recurring basis at December 31, 2018 and 2017. There were no Level 3 investments held by the Pension Plan at December 31, 2018 and 2017.

(In millions)	**December 31, 2018**	**Level 1**	**Level 2**	**Net Asset Value (A)**
Common stocks	**$ 169.3**	**$ 169.3**	**$ —**	**$ —**
U.S. Treasury notes and bonds (B)	**137.9**	**137.9**	**—**	**—**
Mortgage- and asset-backed securities	**65.9**	**—**	**65.9**	**—**
Corporate fixed income and other securities	**143.2**	**—**	**143.2**	**—**
Commingled fund (C)	**19.7**	**—**	**—**	**19.7**
Foreign government bonds	**4.4**	**—**	**4.4**	**—**
U.S. municipal bonds	**0.6**	**—**	**0.6**	**—**
Money market fund	**0.3**	**—**	**—**	**0.3**
Mutual fund	**8.0**	**8.0**	**—**	**—**
Futures:				
U.S. Treasury futures (receivable)	**27.0**	**—**	**27.0**	**—**
U.S. Treasury futures (payable)	**(20.4)**	**—**	**(20.4)**	**—**
Cash collateral	**0.7**	**0.7**	**—**	**—**
Forward contracts:				
Receivable (foreign currency)	**0.1**	**—**	**0.1**	**—**
Total Pension Plan investments	**$ 556.7**	**$ 315.9**	**$ 220.8**	**$ 20.0**
Receivable from broker for securities sold	**—**			
Interest and dividends receivable	**3.0**			
Payable to broker for securities purchased	**(36.9)**			
Total Pension Plan assets	**$ 522.8**			

(A) GAAP allows the measurement of certain investments that do not have a readily determinable fair value at the net asset value. These investments do not consider the observability of inputs; therefore, they are not included within the fair value hierarchy.

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

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

(In millions)	December 31, 2017	Level 1	Level 2	Net Asset Value (A)
Common stocks	$ 225.9	$ 225.9	$ —	$ —
U.S. Treasury notes and bonds (B)	169.7	169.7	—	—
Mortgage- and asset-backed securities	43.4	—	43.4	—
Corporate fixed income and other securities	153.8	—	153.8	—
Commingled fund (C)	29.9	—	—	29.9
Foreign government bonds	4.0	—	4.0	—
U.S. municipal bonds	1.2	—	1.2	—
Money market fund	4.3	—	—	4.3
Mutual fund	7.8	7.8	—	—
Futures:				
U.S. Treasury futures (receivable)	13.4	—	13.4	—
U.S. Treasury futures (payable)	(11.4)	—	(11.4)	—
Cash collateral	0.3	0.3	—	—
Forward contracts:				
Receivable (foreign currency)	0.1	—	0.1	—
Total Pension Plan investments	$ 642.4	$ 403.7	$ 204.5	$ 34.2
Receivable from broker for securities sold	—			
Interest and dividends receivable	3.2			
Payable to broker for securities purchased	(10.3)			
Total Pension Plan assets	$ 635.3			

(A) GAAP allows the measurement of certain investments that do not have a readily determinable fair value at the net asset value. These investments do not consider the observability of inputs; therefore, they are not included within the fair value hierarchy.

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

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

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 stocks, U.S. Treasury notes and bonds, mutual funds and cash collateral.

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 mortgage- and asset-backed securities, corporate fixed income and other securities, foreign government bonds, U.S. municipal bonds, U.S. Treasury futures contracts 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.

Postretirement Plans Investments

The following tables summarize the postretirement benefit plans' investments that are measured at fair value on a recurring basis at December 31, 2018 and 2017. There were no Level 2 investments held by the postretirement benefit plans at December 31, 2018 and 2017.

(In millions)	**December 31, 2018**	**Level 1**	**Level 3**
Group retiree medical insurance contract	**$ 36.0**	**$ —**	**$ 36.0**
Mutual funds	**8.9**	**8.9**	**—**
Cash	**0.9**	**0.9**	**—**
Total plan investments	**$ 45.8**	**$ 9.8**	**$ 36.0**

(In millions)	December 31, 2017	Level 1	Level 3
Group retiree medical insurance contract	$ 40.2	$ —	$ 40.2
Mutual funds	9.5	9.5	—
Cash	0.5	0.5	—
Total plan investments	$ 50.2	$ 10.0	$ 40.2

The group retiree medical insurance contract invests in a pool of common stocks, bonds and money market accounts, of which a significant portion is comprised of mortgage-backed securities. 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)*	**2018**
Group retiree medical insurance contract:	
Beginning balance	**$ 40.2**
Interest income	**0.7**
Dividend income	**0.5**
Claims paid	**(4.6)**
Net unrealized losses related to instruments held at the reporting date	**(0.5)**
Realized losses	**(0.2)**
Investment fees	**(0.1)**
Ending balance	**$ 36.0**

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
2019	$	11.6
2020	$	11.6
2021	$	11.6
2022	$	11.6
2023	$	10.2
After 2023	$	46.7

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
2019	$	64.3
2020	$	60.2
2021	$	60.6
2022	$	59.7
2023	$	59.7
After 2023	$	267.6

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 $1.9 million and $2.5 million at December 31, 2018 and 2017, respectively.

401(k) Plan

The Company provides a 401(k) Plan, and 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 reached 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 their 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 requirements, 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 $13.2 million, $13.2 million and $11.9 million in 2018, 2017 and 2016, 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 2018, 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.

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. 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, 2018, 2017 and 2016.

2018	Electric Utility	Natural Gas Midstream Operations	Other Operations	Eliminations	Total
(In millions)					
Operating revenues	$ 2,270.3	$ —	$ —	$ —	$ 2,270.3
Cost of sales	892.5	—	—	—	892.5
Other operation and maintenance	473.8	1.4	(0.6)	—	474.6
Depreciation and amortization	321.6	—	—	—	321.6
Taxes other than income	88.2	0.6	3.2	—	92.0
Operating income (loss)	494.2	(2.0)	(2.6)	—	489.6
Equity in earnings of unconsolidated affiliates	—	152.8	—	—	152.8
Other income (expense)	25.6	(4.9)	(3.4)	(6.0)	11.3
Interest expense	151.8	—	10.2	(6.0)	156.0
Income tax expense (benefit)	40.0	37.1	(4.9)	—	72.2
Net income (loss)	$ 328.0	$ 108.8	$ (11.3)	$ —	$ 425.5
Investment in unconsolidated affiliates	$ —	$ 1,166.6	$ 10.9	$ —	$ 1,177.5
Total assets	$ 9,704.5	$ 1,169.8	$ 184.8	$ (310.5)	$ 10,748.6
Capital expenditures	$ 573.6	$ —	$ —	$ —	$ 573.6

2017	Electric Utility	Natural Gas Midstream Operations	Other Operations	Eliminations	Total
(In millions)					
Operating revenues	$ 2,261.1	$ —	$ —	$ —	$ 2,261.1
Cost of sales	897.6	—	—	—	897.6
Other operation and maintenance	469.8	(0.8)	(10.3)	—	458.7
Depreciation and amortization	280.9	—	2.6	—	283.5
Taxes other than income	84.8	1.0	3.6	—	89.4
Operating income (loss)	528.0	(0.2)	4.1	—	531.9
Equity in earnings of unconsolidated affiliates	—	131.2	—	—	131.2
Other income (expense)	57.7	(1.0)	(5.4)	(0.9)	50.4
Interest expense	138.4	—	6.3	(0.9)	143.8
Income tax expense (benefit) (A)	141.8	(195.2)	4.1	—	(49.3)
Net income (loss)	$ 305.5	$ 325.2	$ (11.7)	$ —	$ 619.0
Investment in unconsolidated affiliates	$ —	$ 1,151.9	$ 8.5	$ —	$ 1,160.4
Total assets	$ 9,255.6	$ 1,155.3	$ 109.1	$ (107.3)	$ 10,412.7
Capital expenditures	$ 824.1	$ —	$ —	$ —	$ 824.1

(A) The Company recorded an income tax benefit of $245.2 million and income tax expense of $10.5 million during the fourth quarter of 2017 due to the Company remeasuring deferred taxes related to the natural gas midstream operations and other operations segments, respectively, as a result of the 2017 Tax Act. See Note 8 for further discussion of the effects of the 2017 Tax Act.

2016	Electric Utility	Natural Gas Midstream Operations	Other Operations	Eliminations	Total
(In millions)					
Operating revenues	$ 2,259.2	$ —	$ —	$ —	$ 2,259.2
Cost of sales	880.1	—	—	—	880.1
Other operation and maintenance	451.2	(0.1)	(13.0)	—	438.1
Depreciation and amortization	316.4	—	6.2	—	322.6
Taxes other than income	84.0	—	3.6	—	87.6
Operating income	527.5	0.1	3.2	—	530.8
Equity in earnings of unconsolidated affiliates	—	101.8	—	—	101.8
Other income (expense)	9.1	(7.7)	(5.4)	(0.2)	(4.2)
Interest expense	138.1	—	4.2	(0.2)	142.1
Income tax expense (benefit)	114.4	40.5	(6.8)	—	148.1
Net income	$ 284.1	$ 53.7	$ 0.4	$ —	$ 338.2
Investment in unconsolidated affiliates	$ —	$ 1,158.6	$ —	$ —	$ 1,158.6
Total assets	$ 8,669.4	$ 1,521.6	$ 89.0	$ (340.4)	$ 9,939.6
Capital expenditures	$ 660.1	$ —	$ —	$ —	$ 660.1

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 office space lease. Future minimum payments for noncancellable operating leases are as follows:

Year Ended December 31 *(In millions)*	**2019**	**2020**	**2021**	**2022**	**2023**	**After 2023**	**Total**
Operating lease obligations:							
Railcars	$ 18.6	$ —	$ —	$ —	$ —	$ —	$ 18.6
Wind farm land leases	2.5	2.9	2.9	2.9	2.9	37.6	51.7
Office space lease	1.0	1.0	0.6	—	—	—	2.6
Total operating lease obligations	$ 22.1	$ 3.9	$ 3.5	$ 2.9	$ 2.9	$ 37.6	$ 72.9

Payments for operating lease obligations were $4.9 million, $6.2 million and $9.3 million for the years ended December 31, 2018, 2017 and 2016, respectively.

OG&E Railcar Lease Agreement

As of December 31, 2018, OG&E has a noncancellable operating lease with a purchase option, covering 1,093 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.

At the end of the lease term, which was February 1, 2019, OG&E had the option to either purchase the railcars at a stipulated fair market value or renew the lease. If OG&E chose not to purchase the railcars or renew the lease agreement and the actual fair value of the railcars was less than the stipulated fair market value, OG&E would have been responsible for the difference in those values up to a maximum of $16.2 million. OG&E was also required to maintain all of the railcars it had under the operating lease.

On February 1, 2019, OG&E renewed the lease agreement effective February 1, 2019, under similar terms and conditions, for a fleet of 780 railcars, expiring February 1, 2024. The number of railcars was reduced due to the conversion of Muskogee Units 4 and 5 to natural gas. At the end of the lease term, 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 $6.8 million. The railcar lease effective February 1, 2019 is not included in the operating lease obligations table above.

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 useful life.

Office Space Lease

In August 2012, the Company executed a noncancellable lease agreement for office space from September 1, 2013 to August 31, 2018. This lease had rent escalations which increased after five years and allowed for leasehold improvements. In February 2018, the Company executed a noncancellable lease agreement for office space from September 1, 2018 to August 31, 2021. This lease 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)	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
Other purchase obligations and commitments:						
Cogeneration capacity and fixed operation and maintenance payments (A)	$ 10.9	$ —	$ —	$ —	$ —	$ 10.9
Expected cogeneration energy payments (A)	2.4	—	—	—	—	2.4
Minimum purchase commitments	75.8	44.6	44.6	44.6	44.6	254.2
Expected wind purchase commitments	56.3	56.9	57.1	57.5	58.0	285.8
Long-term service agreement commitments	46.8	2.4	2.4	2.4	14.4	68.4
Environmental compliance plan expenditures	5.8	0.2	—	—	—	6.0
Total other purchase obligations and commitments	$ 198.0	$ 104.1	$ 104.1	$ 104.5	$ 117.0	$ 627.7

(A) Cogeneration capacity, fixed operation and maintenance and energy payments will end in 2019, as a result of contract expiration. As described below, OG&E intends to acquire the AES and Oklahoma Cogeneration LLC power plants, pending regulatory approval.

Public Utility Regulatory Policy Act of 1978

At December 31, 2018, OG&E has a QF contract with Oklahoma Cogeneration LLC which expires on August 31, 2019 and a QF contract with AES which expired on January 15, 2019. 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, and 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 QF contract and the 120 MWs Oklahoma Cogeneration LLC QF contract, OG&E purchases 100 percent of the electricity generated by the QFs.

As part of the QF contract with AES, OG&E had the option to provide notice to AES to terminate the contract, and on August 24, 2018, OG&E notified AES that OG&E was exercising this option to terminate the contract, effective January 15, 2019. OG&E subsequently issued a request for proposals to fill the capacity need created by the termination of this QF contract. On December 20, 2018, OG&E announced its plan to acquire power plants from AES and Oklahoma Cogeneration LLC, pending regulatory approval, to meet customers' energy needs. Further discussion can be found in Note 15.

For the years ended December 31, 2018, 2017 and 2016, OG&E made total payments to cogenerators of $112.4 million, $115.2 million and $124.8 million, respectively, of which $60.0 million, $63.0 million and $66.3 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 Purchase Commitments

OG&E has coal contracts for purchases through March 31, 2019, whereby OG&E has the right but not the obligation to purchase a defined quantity of coal. OG&E purchases its coal through spot purchases on an as-needed basis. As a participant in the SPP Integrated Marketplace, OG&E purchases its natural gas supply through short-term agreements. OG&E relies on a combination of natural gas call 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 has natural gas transportation service contracts with Enable and ONEOK, Inc. The contract with Enable expires in April 2019, and in October 2018, OG&E and Enable agreed to a new contract that will be effective as of April 2019 for a five year period ending May 2024. The contracts with ONEOK, Inc. end in March 2019 and August 2037. These transportation contracts grant Enable and ONEOK, Inc. the responsibility of delivering natural gas to OG&E's generating facilities.

OG&E Wind Purchase Commitments

OG&E owns the 120 MW Centennial, 101 MW OU Spirit and 228 MW Crossroads wind farms. OG&E's current wind power portfolio also includes purchased power contracts as listed in the table below.

Company	**Location**	**Original Term of Contract**	**Expiration of Contract**	**MWs**
CPV Keenan	Woodward County, OK	20 years	2030	152.0
Edison Mission Energy	Dewey County, OK	20 years	2031	130.0
NextEra Energy	Blackwell, OK	20 years	2032	60.0

The following table summarizes OG&E's wind power purchases for the years ended December 31, 2018, 2017 and 2016.

Year Ended December 31 *(In millions)*	**2018**	2017	2016
CPV Keenan	**$ 27.0**	$ 29.0	$ 29.2
Edison Mission Energy	**21.7**	22.1	21.1
NextEra Energy	**6.8**	7.4	7.3
FPL Energy (A)	**2.1**	2.6	3.4
Total wind power purchased	**$ 57.6**	$ 61.1	$ 61.0

(A) OG&E's purchased power contract with FPL Energy for 50 MWs expired in 2018.

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 Long-Term Service Agreement 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 2031. 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 2029. The contract requires payments based on both a fixed and variable cost component, depending on how much the Redbud Plant is used.

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 the Company's business activities in many ways, including the handling or disposal of waste material, planning for future construction activities to avoid or mitigate harm to threatened or endangered species and requiring the installation and operation of emissions 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. Management believes that all of 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. Management continues to evaluate its compliance with existing and proposed environmental legislation and regulations and implement appropriate environmental programs in a competitive market.

Air Quality Control System

The Dry Scrubber system on Sooner Unit 1 completed certain emission testing in October 2018 and was placed into service. The Dry Scrubber system on Sooner Unit 2 completed certain emission testing in January 2019 and was placed into service. More detail regarding the ECP can be found under "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. However, the rule was challenged in court when it was issued, and the U.S. Supreme Court issued orders staying implementation of the Clean Power Plan on February 9, 2016 pending resolution of the court challenges. The EPA published a proposal on October 16, 2017 to repeal the Clean Power Plan. On August 31, 2018, without acting on the proposed repeal of the Clean Power Plan, the EPA published a proposed rule to replace the Clean Power Plan. The ultimate timing and impact of these standards on OG&E's operations cannot be determined with certainty at this time, although a requirement for significant reduction of CO_2 emissions from existing fossil-fuel-fired power plants ultimately could result in significant additional compliance costs that would affect the Company's future consolidated financial position, results of operations and cash flows if such costs are not recovered through regulated rates.

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 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 2018, 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

Oklahoma Rate Review Filing - January 2018

On January 16, 2018, OG&E filed a general rate review in Oklahoma, requesting a rate increase of $1.9 million per year, assuming a 9.9 percent return on equity. The filing sought recovery of the seven combustion turbines that are part of the Mustang Modernization Plan, an increase in depreciation rates to levels similar with rates in existence prior to the March 2017 OCC rate order and credit to customers for the impacts of the 2017 Tax Act, which was enacted on December 22, 2017.

On December 22, 2017, the Attorney General of Oklahoma requested that the OCC reduce the rates and charges for electric service and provide for an immediate refund due to the customers of OG&E resulting from the 2017 Tax Act. In response, on January 4, 2018, the OCC ordered OG&E to record a reserve, beginning on January 4, 2018, to reflect the reduced federal corporate tax rate of 21 percent and the amortization of excess accumulated deferred income tax and any other tax implications of the 2017 Tax Act on an interim basis, subject to refund until utility rates were adjusted to reflect the federal tax savings and a final order was issued in the rate review. Further, the OCC ordered the amounts of any refunds of such reserves owed to customers should accrue interest at a rate equivalent to OG&E's cost of capital as previously recognized in the March 2017 OCC rate order. OG&E reserved the excess income taxes collected in current rates and any amortization of excess accumulated deferred income taxes associated with the 2017 Tax Act, plus interest, from January 2018 through June 2018.

On June 19, 2018, the OCC approved a Joint Stipulation and Settlement Agreement. Key terms of the settlement include the following:

- an annual net decrease of $64.0 million in OG&E's rates to its Oklahoma retail customers, which reflects recovery of the Mustang Modernization Plan, offset by reductions for the impact of the lower corporate income taxes resulting from the 2017 Tax Act;
- for purposes of calculating the Allowance for Funds Used During Construction and OG&E's various recovery riders that include a full return component, use of the most-recently approved return on equity of 9.5 percent and a capital structure of 47 percent debt/53 percent equity;
- depreciation rates remain unchanged from the current depreciation rates approved in the March 2017 OCC rate order;
- regulatory asset treatment for the Dry Scrubbers at Sooner Units 1 and 2 that will defer the non-fuel operation and maintenance expenses, depreciation, debt cost associated with the capital investment and related ad valorem taxes, subject to a prudence review in a future general rate review and a determination as to whether the project is used and useful;
- production tax credits will be removed from base rates and placed into a separate rider;
- a federal tax credit rider will be established to refund to customers the amount of excess taxes received from January to June 2018, as discussed above, and the ongoing annual true up of excess accumulated deferred income taxes resulting from the reduction in corporate income tax rates as part of the 2017 Tax Act (further discussed in Note 8); and
- the demand program rider tariff will be revised to allow for concurrent recovery of lost revenues from foregone sales due to certain achieved energy efficiency and demand savings.

As a result of the settlement, new rates were implemented on July 1, 2018, reflecting the impacts of the order, and the tax reserve balance estimated for January 2018 through June 2018 of $18.9 million was returned to Oklahoma customers during the July billing cycle. As reserved amounts were estimated through June 2018, a true-up mechanism exists for the difference between the estimate and actuals to be calculated after the determination of year-end financial results.

Demand Program Rider - Energy Efficiency Lost Net Revenues

During the May 2017 implementation of new rates from the March 2017 OCC rate order, OG&E reserved $5.6 million, pending resolution of a dispute with the OCC's Public Utility Division staff regarding recovery of certain lost revenues associated with energy efficiency programs incurred prior to the March 2017 OCC rate order. These lost revenues are recovered through the Demand Program Rider as disclosed in Note 1. This dispute was resolved through the June 19, 2018 Oklahoma rate review settlement discussed above; as a result, the reserve was reversed at June 30, 2018, and an adjustment was recorded to the Demand Program Rider regulatory asset balance.

Fuel Adjustment Clause Review for Calendar Year 2016

On August 3, 2017, the OCC's Public Utility Division staff filed an application to review OG&E's fuel adjustment clause for calendar year 2016, including the prudence of OG&E's electric generation, purchased power and fuel procurement costs. On February 7, 2018, an intervenor filed a recommendation to disallow the Oklahoma jurisdictional portion of $3.3 million related to wind sales in the SPP. On April 4, 2018, a Joint Stipulation and Settlement Agreement was filed with the OCC. As part of the agreement, the stipulating parties settled all claims regarding the issue of wind energy settlement costs for the period September 2016 through May 2017, and OG&E agreed to refund $2.4 million to customers related to wind sales in the SPP. On April 25, 2018, the OCC approved the Joint Stipulation and Settlement Agreement, and in May 2018, OG&E refunded this settlement amount to customers.

FERC - Request for Waiver

On May 22, 2018, OG&E submitted a request for waiver of applicable formula rate provisions in OG&E's Open Access Transmission Tariff and the SPP's Open Access Transmission Tariff. OG&E requested a waiver, effective January 1, 2018, to revise its 2018 projected net revenue requirement to reflect the federal corporate income tax rate reduction from 35 percent to 21 percent as a result of the 2017 Tax Act. On June 29, 2018, the FERC granted OG&E's request for waiver, effective January 1, 2018, which will allow OG&E to lower its current year projected net revenue requirement and provide benefits to customers through lower rates more promptly than if OG&E were to wait until the current year true-up adjustment to recognize the reduced federal corporate income tax rate. Based on the order received from the FERC, OG&E reserved the excess income taxes collected in current rates from January 2018 through June 2018, as the new tax rate was reflected in billings beginning with the July 2018 invoice. As the SPP adjusts the rates billed to OG&E's customers, OG&E reverses the reserve as the previous months in 2018 are resettled based on the lower tax rate.

APSC Order - 2017 Tax Act

On January 12, 2018, as a result of the 2017 Tax Act, the APSC ordered OG&E to prepare and file an analysis of the ratemaking effects of the 2017 Tax Act on OG&E's revenue requirement and begin, effective January 1, 2018, to book regulatory liabilities to record the current and deferred impacts of the 2017 Tax Act. On July 26, 2018, the APSC ordered OG&E to file a separate rider that includes the reduction in tax expense due to the 2017 Tax Act and amortization of the applicable excess accumulated deferred income taxes as a reduction in revenue requirement. On August 27, 2018, OG&E filed the request for a new Tax Adjustment Rider as well as filed updates to all riders with tax implications, which were then approved by the APSC on September 24, 2018. All rider changes were implemented on October 1, 2018. In October 2018, OG&E refunded the excess income taxes collected from January 1, 2018 through September 30, 2018 and also began refunding the amortization of excess accumulated deferred income taxes associated with the 2017 Tax Act, plus carrying charges, from January 2018 through September 2018, which was approximately $7.7 million. As reserved amounts were estimated through September 2018, a true-up mechanism exists for the difference between the estimate and actuals to be calculated after the determination of year-end financial results.

Integrated Resource Plans

In September 2018, OG&E submitted its final 2018 IRP to the OCC and the APSC. The 2018 IRP identified a need for capacity, and OG&E issued a request for proposals to identify options to fill that capacity need. See "Pre-Approval for Acquisition of Existing Power Plants" under "Pending Regulatory Matters" for further discussion regarding the outcome of the request for proposal process.

Demand Program Portfolio Filing

Pursuant to OCC rules, OG&E is required to propose, implement and administer a portfolio of demand programs once every three years. On July 1, 2018, OG&E filed its proposed Demand Program Three Year Portfolio for the 2019 through 2021 program cycle, and on December 27, 2018, the OCC approved OG&E's 2019 through 2021 demand portfolio programs.

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.

Environmental Compliance Plan

On August 6, 2014, OG&E filed an application under Oklahoma Statute Title 17, Section 286 (B) with the OCC for approval of its plan to comply with the EPA's MATS and Regional Haze Rule FIP while serving the best long-term interests of customers in light of future environmental uncertainties. The application sought approval of the ECP, which includes installing Dry Scrubbers at Sooner Units 1 and 2 and the conversion of Muskogee Units 4 and 5 to natural gas, as well as a recovery mechanism for the associated costs. The application also asked the OCC to predetermine the prudence of its Mustang Modernization Plan and approval for a recovery mechanism for the associated costs.

On December 2, 2015, OG&E received an order from the OCC denying its plan to comply with the environmental mandates of the Federal Clean Air Act, Regional Haze Rule 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 under Oklahoma Statute Title 17, Section 286 (B), and on December 23, 2015, the OCC rejected OG&E's motion.

On February 12, 2016, OG&E filed an application under Oklahoma Statute Title 17, Section 151, *et seq.* requesting the OCC to issue an order approving its decision to install Dry Scrubbers at the Sooner facility. OG&E's application did not seek approval of the costs of the Dry Scrubber project. Instead, the reasonableness of the costs would be considered after the project is completed, and OG&E seeks recovery in a general rate review. On April 28, 2016, the OCC approved the Dry Scrubber project.

Two parties appealed the OCC's decision to the Oklahoma Supreme Court. On April 24, 2018, the Oklahoma Supreme Court ruled that the OCC did not have the authority to grant pre-approval of OG&E's Dry Scrubber project outside the authority of Oklahoma Statute Title 17, Section 286 (B).

OG&E anticipates the total cost of Dry Scrubbers will be $520.0 million, including allowance for funds used during construction and capitalized ad valorem taxes. The Dry Scrubber system on Sooner Unit 1 completed certain emission testing in October 2018 and was placed into service. The Dry Scrubber system on Sooner Unit 2 completed certain emission testing in January 2019 and was placed into service. As of December 31, 2018, OG&E has invested $504.3 million in the Dry Scrubbers. On December 31, 2018, OG&E filed a rate review with the OCC seeking recovery for the Dry Scrubber project, as further discussed below.

FERC - Section 206 Filing

In January 2018, the Oklahoma Municipal Power Authority filed a complaint at the FERC stating that the base return on common equity used by OG&E in calculating formula transmission rates under the SPP Open Access Transmission Tariff is unjust and unreasonable and should be reduced from 10.60 percent to 7.85 percent, effective upon the date of the complaint. The Company has reserved an amount within this range. The Company estimates that if the FERC ultimately orders a reduction, each 25 basis point reduction in the requested return on equity would reduce the Company's SPP Open Access Transmission Tariff transmission revenues by approximately $1.5 million annually. The Company contested the reduction of its base return on equity. While the Company is unable to predict what final action the FERC will take in response to the Oklahoma Municipal Power Authority's complaint or the timing of such action, if the FERC orders revenue reductions as a result of the complaint, including refunds from the date of the complaint filing, it could have a material adverse effect on the Company's financial position, results of operations and cash flows.

In addition to the request to reduce the return on equity, the Oklahoma Municipal Power Authority's complaint also requests that modifications be made to OG&E's transmission formula rates to reflect the impacts of the 2017 Tax Act, including the 2017 Tax Act's impact on accumulated deferred income tax balances. Based on an order received from the FERC, OG&E reserved the excess income taxes collected in current rates from January 2018 through June 2018, as the new tax rate was reflected in billings beginning with the July 2018 invoice, as discussed under "FERC - Request for Waiver" above. Further, OG&E is also reserving any amortization of excess accumulated deferred income taxes associated with the 2017 Tax Act.

Fuel Adjustment Clause Review for Calendar Year 2017

On July 9, 2018, the OCC staff filed an application to review OG&E's fuel adjustment clause for the calendar year 2017, including the prudence of OG&E's electric generation, purchased power and fuel procurement costs. A hearing on the merits was held in December 2018, and on February 1, 2019, the Administrative Law Judge recommended that OG&E's processes, costs, investments and decisions regarding fuel procurement for the 2017 calendar year be found prudent. This recommendation is subject to OCC approval.

Arkansas Formula Rate Plan Filing

Per OG&E's settlement in its last general rate review in Arkansas, OG&E filed an evaluation report under its Formula Rate Plan on October 1, 2018, requesting a $6.4 million revenue increase. On January 30, 2019, OG&E and settling parties reached a settlement agreement for a $3.3 million revenue increase. The settlement agreement is subject to APSC approval. A final order is expected from the APSC in March 2019, and new rates will become effective on April 1, 2019.

Oklahoma Rate Review Filing - December 2018

On December 31, 2018, OG&E filed a general rate review with the OCC, requesting a rate increase of $77.6 million per year to recover its investment in the Dry Scrubbers project and in the conversion of Muskogee Units 4 and 5 to natural gas to comply with the Regional Haze Rule. The filing also seeks to align OG&E's return on equity more closely to the industry average and to align OG&E's depreciation rates to more realistically reflect its assets' lifespans.

Pre-Approval for Acquisition of Existing Power Plants

On December 28, 2018, OG&E filed an application for pre-approval from the OCC to acquire a 360 MW coal- and natural gas-fired plant from AES and a 146 MW natural gas-fired combined-cycle plant from Oklahoma Cogeneration LLC in 2019 for $53.5 million. The purchase of these assets is intended to replace capacity currently provided by power purchase contracts set to expire in 2019 and to help OG&E satisfy its customers' energy needs and load obligations to the SPP. In addition, the filing seeks approval of a rider mechanism to collect costs associated with the purchase of these generating facilities.

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	**2018**	**$ 492.7**	**$ 567.0**	**$ 698.8**	**$ 511.8**	**$ 2,270.3**
	2017	$ 456.0	$ 586.4	$ 716.8	$ 501.9	$ 2,261.1
Operating income	**2018**	**$ 66.6**	**$ 137.7**	**$ 227.3**	**$ 58.0**	**$ 489.6**
	2017	$ 49.8	$ 147.3	$ 249.1	$ 85.7	$ 531.9
Net income	**2018**	**$ 55.0**	**$ 110.7**	**$ 205.1**	**$ 54.7**	**$ 425.5**
	2017	$ 36.0	$ 104.8	$ 183.4	$ 294.8	$ 619.0
Basic earnings per average common share (A)	**2018**	**$ 0.28**	**$ 0.55**	**$ 1.03**	**$ 0.27**	**$ 2.13**
	2017	$ 0.18	$ 0.52	$ 0.92	$ 1.48	$ 3.10
Diluted earnings per average common share (A)	**2018**	**$ 0.27**	**$ 0.55**	**$ 1.02**	**$ 0.27**	**$ 2.12**
	2017	$ 0.18	$ 0.52	$ 0.92	$ 1.48	$ 3.10

(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

To the Board of Directors and Stockholders of OGE Energy Corp.

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets and consolidated statements of capitalization of OGE Energy Corp. (the "Company") as of December 31, 2018 and 2017, the related consolidated statements of income, comprehensive income, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes and financial statement schedule listed in the Index at Item 15(a) (collectively referred to as the "consolidated financial statements"). In our opinion, based on our audit and the report of other auditors, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles.

We did not audit the consolidated financial statements of Enable Midstream Partners, LP ("Enable"), a partnership in which the Company has a 25.6% interest at December 31, 2018. The Company's investment in Enable constituted 10.9 percent and 11.1 percent of the Company's assets as of December 31, 2018 and 2017, respectively, and the Company's equity earnings in the net income of Enable constituted 30.7 percent, 23.0 percent and 20.9 percent of the Company's income before taxes for the years ended December 31, 2018, 2017, 2016, 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 also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2018, 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 20, 2019, expressed an unqualified opinion thereon.

Basis for Opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma

February 20, 2019

We have served as the Company's auditor since 2002.

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, 2018. 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, 2018, 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/ Sarah R. Stafford
Sean Trauschke, Chairman of the Board, President and Chief Executive Officer	Sarah R. Stafford, Controller and Chief Accounting Officer

/s/ Stephen E. Merrill
Stephen E. Merrill Chief Financial Officer

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Stockholders and Board of Directors of OGE Energy Corp.

Opinion on Internal Control over Financial Reporting

We have audited OGE Energy Corp.'s internal control over financial reporting as of December 31, 2018, 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). In our opinion, OGE Energy Corp. (the Company) maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the COSO criteria.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the 2018 consolidated financial statements of the Company and our report dated February 20, 2019 expressed an unqualified opinion thereon.

Basis for Opinion

The Company'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 are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. 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.

Definition and Limitations of Internal Control over Financial Reporting

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.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma

February 20, 2019

Item 9B. Other Information.

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

Code of Ethics Policy

The Company maintains a code of ethics for our chief executive officer and senior financial officers, including the chief financial officer and chief accounting officer, which is available for public viewing on the Company's website address *www.ogeenergy.com* under the heading "Investors," "Governance." The code of ethics will be provided, free of charge, upon request. The Company intends to satisfy the disclosure requirements under Section 5, Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of the code of ethics by posting such information on its website at the location specified above. The Company 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 Accountant Fees and Services.

Items 10 through 14 (other than Item 10 information regarding the Code of Ethics) are omitted pursuant to General Instruction G of Form 10-K, because the Company will file copies of a definitive proxy statement with the Securities and Exchange Commission on or about April 1, 2019. 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, 2018, 2017 and 2016
- Consolidated Statements of Comprehensive Income for the years ended December 31, 2018, 2017 and 2016
- Consolidated Statements of Cash Flows for the years ended December 31, 2018, 2017 and 2016
- Consolidated Balance Sheets at December 31, 2018 and 2017
- Consolidated Statements of Capitalization at December 31, 2018 and 2017
- Consolidated Statements of Changes in Stockholders' Equity for the years ended December 31, 2018, 2017 and 2016
- 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 99.02.

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 2.02 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 February 22, 2017. (Filed as Exhibit 3.01 to OGE Energy's Form 8-K filed February 23, 2017 (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 OG&E's 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. 33-1532) 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. 33-1532) 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 OG&E's 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 4.02 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 being a supplemental instrument to Exhibit 4.01 hereto. (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 being supplemental instrument to Exhibit 4.01 hereto. (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 being a supplemental instrument to Exhibit 4.01 hereto. (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	Supplemental Indenture No. 16 dated as of March 15, 2017 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed March 31, 2017 (File No. 1-1097) and incorporated by reference herein).
4.16	Supplemental Indenture No. 17 dated as of August 1, 2017 being supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to OG&E's Form 8-K filed August 11, 2017 (File No. 1-1097) and incorporated by reference herein).
4.17	Supplemental Indenture No. 18 dated as of April 26, 2018 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.21 to the Company's Registration Statement on Form S-3ASR filed May 18, 2018 (File No. 333-225030) and incorporated by reference herein).
4.18	Supplemental Indenture No. 19 dated as of August 15, 2018 being a supplemental instrument to Exhibit 4.01 hereto. (Filed as Exhibit 4.01 to the Company's Form 8-K filed August 17, 2018 (File No. 1-12579) and incorporated by reference herein).
4.19	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).
4.20	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).
4.21	Supplemental Indenture No. 3 dated as of April 26, 2018 being a supplemental instrument to Exhibit 4.19 hereto. (Filed as Exhibit 4.04 to the Company's Registration Statement on Form S-3ASR filed May 18, 2018 (File No. 333-225030) and incorporated by reference herein).
10.01	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).

10.02	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).
10.03	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).
10.04*	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).
10.05	Credit Agreement dated as of March 8, 2017 by and among OGE Energy Corp. and JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Banks, Ltd., MUFG Union Bank, N.A., Royal Bank of Canada and U.S. Bank National Association, as Co-Documentation Agents, and the lenders from time to time parties thereto. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed March 8, 2017 (File No. 1-12579) and incorporated by reference herein).
10.06	Credit Agreement dated as of March 8, 2017 by and among Oklahoma Gas and Electric Company and JPMorgan Chase Bank, N.A., as Syndication Agent, Mizuho Banks, Ltd., MUFG Union Bank, N.A., Royal Bank of Canada and U.S. Bank National Association, as Co-Documentation Agents, and the lenders from time to time parties thereto. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed March 8, 2017 (File No. 1-12579) and incorporated by reference herein).
10.07*	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).
10.08*	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).
10.09*	Form of Employment Agreement for all existing and future officers of OGE Energy 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).
10.10	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).
10.11*	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).
10.12*	Director Compensation.
10.13*	Executive Officer Compensation.
10.14	Fifth Amended and Restated Agreement of Limited Partnership of Enable Midstream Partners, LP, dated November 14, 2017. (Filed as Exhibit 3.1 to Enable Midstream Partners, LP's Form 8-K filed November 15, 2017 (File No. 1-36413) and incorporated by reference herein).
10.15	Third Amended and Restated Limited Liability Company Agreement of Enable GP, LLC, dated June 22, 2016. (Filed as Exhibit 10.02 to OGE Energy's Form 8-K filed June 28, 2016 (File No. 1-12579) and incorporated by reference herein).
10.16	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).
10.17	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).
10.18*	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).
10.19*	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).
10.20*	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 for the quarter ended September 30, 2013 (File No. 1-12579) and incorporated by reference herein).
10.21*	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 for the quarter ended September 30, 2013 (File No. 1-12579) and incorporated by reference herein).

10.22*	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 for the quarter ended September 30, 2013 (File No. 1-12579) and incorporated by reference herein).
10.23*	Form of Performance Unit Agreement under OGE Energy's 2013 Stock Incentive Plan. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended June 30, 2017 (File No. 1-12579) and incorporated by reference herein).
10.24*	Form of Restricted Stock Agreement under OGE Energy's 2013 Stock Incentive Plan. (Filed as Exhibit 10.36 to OGE Energy's Form 10-K for the year ended December 31, 2016 (File No. 1-12579) and incorporated by reference herein).
10.25*	OGE Energy Corp. Deferred Compensation Plan (As amended and restated effective October 1, 2016). (Filed as Exhibit 10.37 to OGE Energy's Form 10-K for the year ended December 31, 2016 (File No. 1-12579) and incorporated by reference herein).
10.26	Copy of the Settlement Agreement filed with the APSC on April 20, 2017. (Filed as Exhibit 99.02 to OGE Energy's Form 8-K filed May 24, 2017 (File No. 1-12579) and incorporated by reference herein).
10.27	Letter of extension dated as of March 9, 2018 for the Company's and OG&E's credit agreements dated as March 8, 2017, by and among Wells Fargo Bank, National Association, as Administrative Agent, JPMorgan Chase Bank, N.A., Syndication Agent, Mizuho Bank, Ltd. MUFG Union Bank, N.A. Royal Bank of Canada and U.S. Bank National Association, as Co-Documentation Agents, the Lenders thereto, and the Company and OG&E, for their respective credit facility. (Filed as Exhibit 10.01 to OGE Energy's Form 10-Q for the quarter ended March 31, 2018 (File No. 1-12579) and incorporated by reference herein).
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	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).
99.02	Financial Statements of Enable Midstream Partners, LP as of and for the three years ended December 31, 2018.
99.03	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).
99.04	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).
99.05	Copy of the APSC Settlement Agreement approval dated May 18, 2017. (Filed as Exhibit 99.01 to OGE Energy's Form 8-K filed May 24, 2017 (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, 2016				
Reserve for Uncollectible Accounts	$ 1.4	$ 2.5	$ 2.4	$ 1.5
Balance at December 31, 2017				
Reserve for Uncollectible Accounts	$ 1.5	$ 2.6	$ 2.6	$ 1.5
Balance at December 31, 2018				
Reserve for Uncollectible Accounts	**$ 1.5**	**$ 1.6**	**$ 1.4**	**$ 1.7**

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

Item 16. Form 10-K Summary.

None.

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 February 20, 2019.

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 20, 2019
/s/ Stephen E. Merrill Stephen E. Merrill	Principal Financial Officer;	February 20, 2019
/s/ Sarah R. Stafford Sarah R. Stafford	Principal Accounting Officer.	February 20, 2019
Frank A. Bozich	Director;	
James H. Brandi	Director;	
Peter D. Clarke	Director;	
Luke R. Corbett	Director;	
David L. Hauser	Director;	
Robert O. Lorenz	Director;	
Judy R. McReynolds	Director;	
David E. Rainbolt	Director;	
J. Michael Sanner	Director;	
Sheila G. Talton	Director;	
/s/ Sean Trauschke By Sean Trauschke (attorney-in-fact)		February 20, 2019

Exhibit 10.12

OGE Energy Corp.
Director Compensation

Compensation of non-management directors of OGE Energy Corp. (the "Company") in 2018 included an annual retainer fee of $225,000, of which $100,000 was payable in cash in quarterly installments and $125,000 was deposited in the director's account under the Company's Deferred Compensation Plan and converted to 3,028 common stock units based on the closing price of the Company's Common Stock on December 11, 2018. In 2018, the non-management directors did not receive additional compensation for attending Board or committee meetings but were instead paid a quarterly cash retainer that was increased from the previous year. The lead director received an additional $25,000 cash retainer in 2018. The chair of the Audit Committee received an additional $15,000 cash retainer in 2018. The chair of each of the Compensation and Nominating and Corporate Governance Committees received an additional $12,500 annual cash retainer in 2018. Each member of the Audit Committee also received an additional annual retainer of $5,000. These amounts represent the total fees paid to directors in their capacities as directors of the Company and Oklahoma Gas and Electric Company in 2018.

Under the Company's Deferred Compensation Plan, non-management directors may defer payment of all or part of their quarterly cash retainer fee, which deferred amounts in 2018 were credited to their account as of the quarterly scheduled payment date. 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 2018, 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.

On December 4, 2018, the Compensation Committee met to consider director compensation. At that meeting, the Compensation Committee increased the annual equity retainer, noted above, credited on December 11, 2018, from $110,000 to $125,000.

Exhibit 10.13

OGE Energy Corp.
Executive Officer Compensation

Executive Compensation

In December 2018, the Compensation Committee of the OGE Energy Corp. (the "Company") board of directors took actions setting executives' salaries, target amount of annual bonus awards and target amounts of long-term compensation awards for 2019. 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 2019 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 2019 for the OGE Energy officers who are expected to be named in the Summary Compensation Table in OGE Energy's 2019 Proxy Statement are as follows:

Executive Officer	2019 Base Salary
Sean Trauschke, Chairman, President and Chief Executive Officer	$1,050,005
Stephen E. Merrill, Chief Financial Officer	$485,014
E. Keith Mitchell, Chief Operating Officer of OG&E	$519,002
Jean C. Leger, Jr., Vice President, Utility Operations of OG&E	$375,003
William H. Sultemeier, General Counsel	$438,006

Establishment of 2019 Annual Incentive Awards

As stated above, at its December 2018 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 2019 corporate goals to receive from 0 percent to 150 percent of such targeted amount. For 2019, the targeted amount ranged from 60 percent to 100 percent of the approved 2019 base salary for the executive officers in the above table.

Establishment of Long-Term Awards

At its December 2018 meeting, the Compensation Committee also approved the level of target long-term incentive awards, expressed as a percentage of salary. For 2019, the targeted amount ranged from 115 percent to 310 percent of the approved 2019 base salary for the executive officers in the above table. The performance-based portion of the long-term incentive awards allow the officer 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.

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. No employees of the Company currently participate 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) an after-tax Roth contribution; or (iii) a contribution made on a non Roth after-tax basis. The 401(k) Plan also includes an eligible automatic contribution arrangement and provides for a qualified default investment alternative consistent with the U.S. Department of Labor regulations. Participants may elect, in accordance with the 401(k) Plan procedures, to have his or her future salary deferral rate to be automatically increased annually on a date and in an amount as specified by the participant in such election. 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. The Company contribution for employees hired or rehired before December 1, 2009 varies depending on the participant's hire date, election with respect to participation in the Pension Plan and, in some cases, years of service.

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 2018, those investment options included an OGE Energy Common Stock fund, whose value was determined based on the stock price of OGE Energy'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, 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 401(k) Plan, Deferred Compensation Plan, Pension Plan and Restoration of Retirement Income Plan, the Compensation Committee seeks 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 performance units will vest and be paid out immediately in cash as if the applicable performance goals had been satisfied at target levels; all restricted stock units will vest and be paid out immediately in cash; 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 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. 333-92423) 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, 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 (Form S-3ASR No. 333-221303) pertaining to the dividend reinvestment and stock purchase plan and the Registration Statement (Form S-3ASR No. 333-225030) pertaining to common stock and debt securities of our reports dated February 20, 2019, 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, 2018.

/s/ Ernst & Young LLP

Oklahoma City, Oklahoma
February 20, 2019

Exhibit 23.02

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement Nos. 333-92423, 333-104497, 333-190406, and 333-190405 on Form S-8; Registration Statement Nos. 333-225030, and 333-221303 on Form S-3ASR of our report dated February 19, 2019 relating to the consolidated financial statements of Enable Midstream Partners, LP and subsidiaries appearing in this Annual Report on Form 10-K of OGE Energy Corp. for the year ended December 31, 2018.

/s/ Deloitte & Touche LLP

Oklahoma City, Oklahoma
February 20, 2019

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, 2018; 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 SARAH R. STAFFORD 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 or her 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 20th day of February, 2019.

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
Peter D. Clarke, Director	/s/ Peter D. Clarke
Luke R. Corbett, Director	/s/ Luke R. Corbett
David L. Hauser, Director	/s/ David L. Hauser
Robert O. Lorenz, Director	/s/ Robert O. Lorenz
Judy R. McReynolds, Director	/s/ Judy R. McReynolds
David E. Rainbolt, Director	/s/ David E. Rainbolt
J. Michael Sanner, Director	/s/ J. Michael Sanner
Sheila G. Talton, Director	/s/ Sheila G. Talton
Stephen E. Merrill, Principal Financial Officer	/s/ Stephen E. Merrill
Sarah R. Stafford, Principal Accounting Officer	/s/ Sarah R. Stafford

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 20th day of February, 2019.

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

My commission expires:
July 6, 2021

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 20, 2019

/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 20, 2019

/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, 2018, 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 20, 2019

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

/s/ Stephen E. Merrill
Stephen E. Merrill
Chief Financial Officer

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

Opinion on the Financial Statements

We have audited the accompanying consolidated balance sheets of Enable Midstream Partners, LP and subsidiaries (the "Partnership") as of December 31, 2018 and 2017, the related consolidated statements of income, cash flows, and partners' equity for each of the three years in the period ended December 31, 2018, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Partnership as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Partnership's internal control over financial reporting as of December 31, 2018, based on criteria established in *Internal Control—Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 19, 2019, expressed an unqualified opinion on the Partnership's internal control over financial reporting.

Basis for Opinion

These financial statements are the responsibility of the Partnership's management. Our responsibility is to express an opinion on the Partnership's financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Partnership in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ DELOITTE & TOUCHE LLP

Oklahoma City, Oklahoma
February 19, 2019

We have served as the Partnership's auditor since 2013.

ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF INCOME

	Year Ended December 31, 2018	2017	2016
	(In millions, except per unit data)		
Revenues (including revenues from affiliates (Note 15)):			
Product sales	$ 2,106	$ 1,653	$ 1,172
Service revenue	1,325	1,150	1,100
Total Revenues	3,431	2,803	2,272
Cost and Expenses (including expenses from affiliates (Note 15)):			
Cost of natural gas and natural gas liquids (excluding depreciation and amortization shown separately)	1,819	1,381	1,017
Operation and maintenance	388	369	367
General and administrative	113	95	98
Depreciation and amortization	398	366	338
Impairments (Note 13)	—	—	9
Taxes other than income taxes	65	64	58
Total Cost and Expenses	2,783	2,275	1,887
Operating Income	648	528	385
Other Income (Expense):			
Interest expense	(152)	(120)	(99)
Equity in earnings of equity method affiliate	26	28	28
Total Other Income (Expense)	(126)	(92)	(71)
Income Before Income Taxes	522	436	314
Income tax (benefit) expense	(1)	(1)	1
Net Income	$ 523	$ 437	$ 313
Less: Net income attributable to noncontrolling interests	2	1	1
Net Income Attributable to Limited Partners	$ 521	$ 436	$ 312
Less: Series A Preferred Unit distributions (Note 6)	36	36	22
Net Income Attributable to Common and Subordinated Units (Note 5)	$ 485	$ 400	$ 290
Basic earnings per unit (Note 5)			
Common units	$ 1.12	$ 0.92	$ 0.69
Subordinated units	$ —	$ 0.93	$ 0.68
Diluted earnings per unit (Note 5)			
Common units	$ 1.11	$ 0.92	$ 0.69
Subordinated units	$ —	$ 0.93	$ 0.68

See Notes to the Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED BALANCE SHEETS

	December 31, 2018	December 31, 2017
	(In millions, except units)	
Current Assets:		
Cash and cash equivalents	$ 8	$ 5
Restricted cash	14	14
Accounts receivable, net	290	277
Accounts receivable—affiliated companies	19	18
Inventory	50	40
Gas imbalances	29	37
Other current assets	39	25
Total current assets	449	416
Property, Plant and Equipment:		
Property, plant and equipment	12,899	12,079
Less accumulated depreciation and amortization	2,028	1,724
Property, plant and equipment, net	10,871	10,355
Other Assets:		
Intangible assets, net	663	451
Goodwill	98	12
Investment in equity method affiliate	317	324
Other	46	35
Total other assets	1,124	822
Total Assets	$ 12,444	$ 11,593
Current Liabilities:		
Accounts payable	$ 288	$ 263
Accounts payable—affiliated companies	4	3
Short-term debt	649	405
Current portion of long-term debt	500	450
Taxes accrued	31	32
Gas imbalances	22	12
Accrued compensation	26	32
Customer deposits	38	34
Other	57	48
Total current liabilities	1,615	1,279
Other Liabilities:		
Accumulated deferred income taxes, net	5	6
Regulatory liabilities	23	21
Other	54	38
Total other liabilities	82	65
Long-Term Debt	3,129	2,595
Commitments and Contingencies (Note 16)		
Partners' Equity:		
Series A Preferred Units (14,520,000 issued and outstanding at December 31, 2018 and December 31, 2017, respectively)	362	362
Common units (433,232,411 issued and outstanding at December 31, 2018 and 432,584,080 issued and outstanding at December 31, 2017, respectively)	7,218	7,280
Noncontrolling interests	38	12
Total Partners' Equity	7,618	7,654
Total Liabilities and Partners' Equity	$ 12,444	$ 11,593

See Notes to the Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2018	2017	2016
		(In millions)	
Cash Flows from Operating Activities:			
Net income	$ 523	$ 437	$ 313
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	398	366	338
Deferred income taxes	(1)	(3)	2
Impairments	—	—	9
Loss on sale/retirement of assets	1	7	17
Equity in earnings of equity method affiliate	(26)	(28)	(28)
Return on investment of equity method affiliate	26	28	28
Equity-based compensation	16	15	13
Amortization of debt costs and discount (premium)	(1)	(2)	(3)
Changes in other assets and liabilities:			
Accounts receivable, net	(10)	(23)	(4)
Accounts receivable—affiliated companies	(1)	(5)	8
Inventory	(10)	1	12
Gas imbalance assets	8	4	(18)
Other current assets	(21)	4	6
Other assets	(12)	1	(1)
Accounts payable	4	54	(34)
Accounts payable—affiliated companies	1	—	(6)
Gas imbalance liabilities	10	(23)	10
Other current liabilities	4	(4)	45
Other liabilities	15	5	14
Net cash provided by operating activities	924	834	721
Cash Flows from Investing Activities:			
Capital expenditures	(728)	(416)	(383)
Acquisitions, net of cash acquired	(443)	(298)	—
Proceeds from sale of assets	8	1	1
Proceeds from insurance	2	2	—
Return of investment in equity method affiliate	7	5	15
Net cash used in investing activities	(1,154)	(706)	(367)
Cash Flows from Financing Activities:			
Increase (decrease) in short-term debt	244	405	(236)
Proceeds from long-term debt, net of issuance costs	787	691	—
Repayment of long-term debt	(450)	—	—
Proceeds from revolving credit facility	350	1,200	1,734
Repayment of revolving credit facility	(100)	(1,836)	(1,408)
Repayment of notes payable—affiliated companies	—	—	(363)
Proceeds from issuance of common units, net of issuance costs	2	—	137
Proceeds from issuance of Series A Preferred Units, net of issuance costs	—	—	362
Distributions	(591)	(590)	(561)
Cash paid for employee equity-based compensation	(9)	(2)	—
Net cash provided by (used in) financing activities	233	(132)	(335)
Net Increase (Decrease) in Cash, Cash Equivalents and Restricted Cash	3	(4)	19
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	19	23	4
Cash, Cash Equivalents and Restricted Cash at End of Period	$ 22	$ 19	$ 23

See Notes to the Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
CONSOLIDATED STATEMENTS OF PARTNERS' EQUITY

	Series A Preferred Units		Common Units		Subordinated Units		Noncontrolling Interest	Total Partners' Equity
	Units	Value	Units	Value	Units	Value	Value	Value
				(In millions)				
Balance as of December 31, 2015	—	$ —	214	$ 3,714	208	$ 3,805	$ 12	$ 7,531
Net income	—	22	—	147	—	143	1	313
Issuance of Series A Preferred Units	15	362	—	—	—	—	—	362
Issuance of common units	—	—	10	137	—	—	—	137
Distributions	—	(22)	—	(274)	—	(265)	(1)	(562)
Equity-based compensation, net of units for employee taxes	—	—	—	13	—	—	—	13
Balance as of December 31, 2016	15	$ 362	224	$ 3,737	208	$ 3,683	$ 12	$ 7,794
Net income	—	36	—	266	—	134	1	437
Conversion of subordinated units	—	—	208	3,619	(208)	(3,619)	—	—
Distributions	—	(36)	—	(355)	—	(198)	(1)	(590)
Equity-based compensation, net of units for employee taxes	—	—	1	13	—	—	—	13
Balance as of December 31, 2017	15	$ 362	433	$ 7,280	—	$ —	$ 12	$ 7,654
Net income	—	36	—	485	—	—	2	523
Issuance of common units	—	—	—	2	—	—	—	2
Acquisition of EOCS	—	—	—	—	—	—	28	28
Distributions	—	(36)	—	(551)	—	—	(4)	(591)
Equity-based compensation, net of units for employee taxes	—	—	—	2	—	—	—	2
Balance as of December 31, 2018	15	$ 362	433	$ 7,218	—	$ —	$ 38	$ 7,618

See Notes to the Consolidated Financial Statements

ENABLE MIDSTREAM PARTNERS, LP
NOTES TO THE 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, OGE Energy and ArcLight, pursuant to the terms of the Master Formation Agreement. The Partnership's assets and operations are organized into two reportable segments: (i) gathering and processing and (ii) transportation and storage. The gathering and processing segment primarily provides natural gas and crude oil gathering and natural gas processing services to our producer customers. The transportation and storage segment provides interstate and intrastate natural gas pipeline transportation and storage services primarily to our producer, power plant, LDC and industrial end-user customers. The Partnership's natural gas gathering and processing assets are primarily located in Oklahoma, Texas, Arkansas and Louisiana and serve natural gas production in the Anadarko, Arkoma and Ark-La-Tex Basins. Crude oil gathering assets are located in Oklahoma and serve crude oil production in the SCOOP and STACK plays of the Anadarko Basin and in North Dakota and serve crude oil production in the Bakken Shale formation of the Williston Basin. The Partnership's natural gas transportation and storage assets consist primarily of an interstate pipeline system extending from western Oklahoma and the Texas Panhandle to Louisiana, an interstate pipeline system extending from Louisiana to Illinois, an intrastate pipeline system in Oklahoma, and our investment in SESH, a pipeline extending from Louisiana to Alabama.

CenterPoint Energy and OGE Energy each have 50% of the management interests in Enable GP. Enable GP is the general partner of the Partnership and has no other operating activities. Enable GP is governed by a board made up of two representatives designated by each of CenterPoint Energy and OGE Energy, along with the Partnership's Chief Executive Officer and three independent board members CenterPoint Energy and OGE Energy mutually agreed to appoint. 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, 2018, CenterPoint Energy held approximately 54.0% or 233,856,623 of the Partnership's common units, and OGE Energy held approximately 25.6% or 110,982,805 of the Partnership's common units. Additionally, CenterPoint Energy holds 14,520,000 Series A Preferred Units. See Note 6 for further information related to the Series A Preferred 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.

For the years ended December 31, 2018, 2017 and 2016, the Partnership owned a 50% interest in SESH. See Note 10 for further discussion of SESH. For the years ended December 31, 2018, 2017 and 2016, the Partnership held a 50% ownership interest in Atoka and consolidated Atoka in its Consolidated Financial Statements as EOIT acted as the managing member of Atoka and had control over the operations of Atoka. In addition, for the period November 1, 2018 through December 31, 2018, the Partnership owned a 60% interest in VPP, which is consolidated in its Consolidated Financial Statements as EOCS acted as the managing member of VPP and had control over the operations of VPP.

Basis of Presentation

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

For a description of the Partnership's reportable segments, see Note 19.

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, condensate and produced water 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. The Partnership reflects revenue as Product sales and Service revenue on the 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.

The Partnership recognizes revenue from natural gas gathering, processing, transportation and storage and crude oil, condensate and water gathering services to third parties in accordance with ASU No. 2014-09 "Revenue from Contracts with Customers" (Topic 606) upon its adoption on January 1, 2018. As the Partnership adopted using the modified retrospective method, revenue for all periods prior to January 1, 2018 were recognized in accordance with "Revenue Recognition" (Topic 605). Please see Note 3. "Revenues" in the Notes to the Consolidated Financial Statements under Item 8. "Financial Statements and Supplementary Data" for a description of the impact of adoption. Under Topic 606, revenue is recognized at an amount that reflects the consideration to which the entity expects to be entitled in exchange for transferring goods or services. The determination of that amount and the timing of recognition is based on identifying the contracts with customers, identifying the performance obligations in the contract, determining the transaction price, allocating the transaction price to the performance obligations in the contract, and ultimately recognizing revenue when (or as) the entity satisfies the performance obligation.

Service revenues for gathering, processing, transportation and storage services for the Partnership are recorded each month as services have been completed and performance obligations are met. Product revenues are recognized when control is transferred. Monthly revenues are 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, net or Accounts receivable—affiliated companies, as appropriate, on the Consolidated Balance Sheets and in Total revenues on the Consolidated Statements of Income.

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 had $48 million and $34 million of deferred revenues, including deferred revenue—affiliated companies, included in Other current liabilities and Other long-term liabilities on the Consolidated Balance Sheets at December 31, 2018 and 2017, 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, 2018, 2017 and 2016, one third party purchased approximately 12%, 13% and 22%, respectively, of the NGLs delivered off our system, which accounted for approximately $214 million, $140 million and $129 million, or 6%, 5% and 6%, respectively, of total revenues. Additionally, in the year ended December 31, 2018 and 2017, another third party purchased 8% and 12%, respectively, of the NGLs delivered off our system, which accounted for $152 million and $127 million, respectively, or 4% and 4%, respectively, of total revenues. Other than revenues from affiliates discussed in Note 15, there are no other revenue concentrations with individual customers in the years ended December 31, 2018, 2017 and 2016.

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 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, 2018 or 2017.

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.

Income Taxes

The Partnership’s earnings are not 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 17.

We account for deferred income taxes related to the federal and state jurisdictions using the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the future taxes attributable to the difference between financial statement carrying amounts of assets and liabilities and their respective tax basis. Deferred tax assets are also recognized for the future tax benefits attributable to the expected utilization of tax net operating loss carryforwards. In the event future utilization is determined to be unlikely, a valuation allowance is provided to reduce the tax benefits from such assets. Deferred tax assets and liabilities are measured using enacted tax rates in effect for the period in which the temporary differences and carryforwards are expected to be recovered or settled. The effect of a change in tax rates is recognized in the period which includes the enactment date. The Partnership recognizes interest and penalties as a component of income tax expense.

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 $8 million and $5 million of cash and cash equivalents as of December 31, 2018 and 2017, respectively.

Restricted Cash

Restricted cash consists of cash which is restricted by agreements with third parties. The Consolidated Balance Sheets have $14 million and $14 million of restricted cash as of December 31, 2018 and 2017, respectively.

Accounts Receivable and Allowance for Doubtful Accounts

Accounts receivable are recorded at the invoiced amount and do not typically bear interest. The determination of the allowance for doubtful accounts requires management to make estimates and judgments regarding our customers' ability to pay. The allowance for doubtful accounts is determined based upon specific identification and estimates of future uncollectable amounts. On an ongoing basis, we evaluate our customers' financial strength based on aging of accounts receivable, payment history and review of other relevant information, including ratings agency credit ratings and alerts, publicly available reports and news releases, and bank and trade references. It is the policy of management to review the outstanding accounts receivable at least quarterly, giving consideration to historical bad debt write-offs, the aging of receivables and specific customer circumstances that may impact their ability to pay the amounts due. Based on this review, management determined that a $2 million and $3 million allowance for doubtful accounts was required at December 31, 2018 and 2017, respectively.

Inventory

Materials and supplies inventory is valued at cost and is subsequently recorded at the lower of cost or net realizable value. The Partnership recorded no write-downs to net realizable value related to materials and supplies inventory disposed or identified as excess or obsolete for the year ended December 31, 2018 and $1 million for each of the years ended December 31, 2017 and 2016. Materials and supplies are recorded to inventory when purchased and, as appropriate, subsequently charged to operation and maintenance expense on the 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 net realizable value. During the years ended December 31, 2018, 2017 and 2016, the Partnership recorded write-downs to net realizable value related to natural gas and natural gas liquids inventory of $4 million, $2 million and $3 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 Consolidated Statements of Income.

	December 31,	
	2018	2017
	(In millions)	
Materials and supplies	$ 31	$ 29
Natural gas and natural gas liquids	19	11
Total Inventory	$ 50	$ 40

Gas Imbalances

Gas imbalances occur when the actual amounts of natural gas delivered from or received by the Partnership's pipeline systems 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 13.

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 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 reportable segment level. For more information, see Note 9.

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, 2018 and 2017, these removal costs of $23 million and $21 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 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. For the years ended December 31, 2018, 2017 and 2016, the Partnership capitalized interest and AFUDC of $6 million, $1 million and $4 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. For derivative instruments not designated as hedging instruments, the gain or loss on the derivative is recognized in Product sales in the Consolidated Statements of Income. 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 performance units, time-based phantom units (phantom units) and time-based restricted units (restricted units) are recognized in the 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.

Employee Benefit Plans

On January 1, 2015, the Partnership adopted the 401(k) Savings Plan, covering all full-time employees. Participant contributions are discretionary, and can be up to 70% of compensation, as pre-tax, Roth, and /or after-tax contributions, subject to certain limits. We match 100% of employee contributions up to 6% of each participant's eligible annual compensation, subject to certain limits. Matching contributions provided by the Partnership are immediately vested. The Partnership may also make discretionary profit sharing contributions. Allocations of such profit sharing contributions are based on the proportion of each participant's eligible compensation of the plan year to the total of all participants' eligible compensation, as defined. A participant must be employed on the last day of the Plan year in order to receive an allocation of profit sharing contributions. Profit sharing contributions must be approved by the Board of Directors annually. For the years ended December 31, 2018, 2017 and 2016, the Partnership contributed $19 million, $18 million and $16 million, respectively.

During the years ended December 31, 2018, 2017 and 2016, the Partnership had 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. For the years ended December 31, 2018, 2017 and 2016, the Partnership reimbursed OGE Energy $3 million, $5 million and $7 million, respectively, for these benefits. See Note 15 for further information related to our related party transactions.

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

On November 14, 2017, the General Partner adopted the Fifth Amended and Restated Agreement of Limited Partnership (the Partnership Agreement), to implement certain changes to the Internal Revenue Code enacted by the Bipartisan Budget Act of 2015 relating to partnership audit and adjustment procedures. The Partnership Agreement also removed references to the subordinated units (all of which previously converted into common units) and related provisions.

(2) New Accounting Pronouncements

Accounting Standards to be Adopted in Future Periods

Leases

In February 2016, the FASB issued ASU 2016-02, "Leases (ASC 842)." This standard requires, among other things, that lessees recognize the following for all leases (with the exception of short-term leases) at the commencement date: (1) a lease liability, which is a lessee's obligation to make lease payments arising from a lease, measured on a discounted basis; and (2) a right-of-use asset, which is an asset that represents the lessee's right to use, or control the use of, a specified asset for the lease term. Lessees and lessors must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements.

In January 2018, the FASB issued ASU 2018-01, “Land Easement Practical Expedient for Transition to Topic 842.” This standard permits an entity to elect an optional transition practical expedient to not evaluate land easements that exist or expire before the Partnership's adoption of ASC 842 and that were not previously accounted for as leases under ASC 840. The Partnership intends to elect this transition provision.

In July 2018, the FASB issued ASU No. 2018-10, “Codification Improvements to Topic 842, Leases” to address implementation issues that could arise as organizations comply with ASC 842.

In July 2018, the FASB issued ASU No. 2018-11, “Leases (Topic 842) - Targeted Improvements” to assist stakeholders with implementation questions and issues as organizations prepare to adopt ASC 842. These questions and issues relate primarily to (1) comparative reporting requirements for initial adoption; and (2) for lessors only, separating lease and non-lease components in a contract and allocating the consideration in the contract to the separate components.

In December 2018, the FASB issued ASU No. 2018-20, “Leases (Topic 842) - Narrow-Scope Improvements for Lessors” to address stakeholders’ concerns regarding: (1) sales taxes and similar taxes collected from lessees; (2) certain lessor costs paid directly by lessees; and (3) recognition of variable payments for contracts with lease and non-lease components.

Based upon the Partnership’s continuing assessment of contracts and easements relative to the provisions of the ASU No. 2016-02 lease standard, the ASU No. 2018-01 easement standard, the ASU No. 2018-10 codification improvements standard, the ASU No. 2018-11 targeted improvements standard and ASU No. 2018-20 improvements for lessors standard, the Partnership anticipates the adoption of ASC No. 842 will increase our asset and liability balances on the Consolidated Balance Sheets by approximately $35 million due to the required recognition of right-of-use assets and corresponding lease liabilities for all lease obligations that are currently classified as operating leases. We continue to develop the underlying reports, internal controls and disclosures to record activity under Topic 842 upon adoption. The Partnership adopted Topic 842 on January 1, 2019 on a retrospective basis as of that date. Upon adoption, the Partnership did not recognize a material cumulative adjustment to the Consolidated Statement of Partners’ Equity and we do not expect any material changes in the timing of expense recognition or our accounting policies.

Financial Instruments—Credit Losses

In June 2016, the FASB issued ASU No. 2016-13, “Financial Instruments—Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments.” This standard requires entities to measure all expected credit losses of financial assets held at a reporting date based on historical experience, current conditions, and reasonable and supportable forecasts in order to record credit losses in a more timely matter. ASU 2016-13 also amends the accounting for credit losses on available-for-sale debt securities and purchased financial assets with credit deterioration. The standard is effective for interim and annual reporting periods beginning after December 15, 2019, although early adoption is permitted for interim and annual periods beginning after December 15, 2018. The Partnership does not expect the adoption of this standard to have a material impact on our Consolidated Financial Statements and related disclosures.

Intangibles—Goodwill and Other

In January 2017, the FASB issued ASU No. 2017-04, “Intangibles-Goodwill and Other (Topic 350): Simplifying the Test for Goodwill Impairment.” This standard requires entities to test goodwill for impairment by eliminating Step 2 from the goodwill impairment test. The standard is effective for interim and annual reporting periods beginning after December 15, 2019. The Partnership does not expect the adoption of this standard to have a material impact on our Consolidated Financial Statements and related disclosures.

Compensation—Stock Compensation

In June 2018, the FASB issued ASU No. 2018-07, “Compensation-Stock Compensation (Topic 718): Improvements to Non-employee Share-Based Payment Accounting.” This standard requires entities to include share-based payment transactions for acquiring goods and services from non-employees. The standard is effective for interim and annual periods beginning after December 15, 2018. The Partnership does not expect the adoption of this standard to have a material impact on our Consolidated Financial Statements and related disclosures.

Fair Value Measurement—Disclosure Framework-Changes to the Disclosure Requirements for Fair Value Measurement

In August 2018, the FASB issued ASU No. 2018-13, “Fair Value Measurement (Topic 820): Disclosure Framework—Changes to the Disclosure Requirements for Fair Value Measurement” which focuses on improving the effectiveness of disclosures in the notes to the financial statements by facilitating clear communication of the information required by GAAP that is most important to users of each entity's financial statements. The standard is effective for interim and annual reporting periods beginning after December 15, 2019, although early adoption is permitted. The Partnership expects to adopt these standards in the first quarter of 2020 and continues to evaluate the other impacts of the new standards on our Consolidated Financial Statements and related disclosures.

Intangibles—Goodwill and Other—Internal-Use Software

In August 2018, the FASB issued ASU No. 2018-15, "Intangibles—Goodwill and Other—Internal-Use Software: Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract", which aims to reduce complexity in the accounting for costs of implementing a cloud computing service arrangement. ASU No. 2018-15 aligns the requirements for capitalizing implementation costs incurred in a hosting arrangement that is a service contract with the requirements for capitalizing implementation costs incurred to develop or obtain internal-use software. The standard is effective for interim and annual periods beginning after December 15, 2019. The Partnership does not expect the adoption of this standard to have a material impact on our Consolidated Financial Statements and related disclosures.

Derivatives and Hedging

In October 2018, the FASB issued ASU No. 2018-16, "Derivatives and Hedging (Topic 815): Inclusion of the Secured Overnight Financing Rate (SOFR) Overnight Index Swap (OIS) Rate as a Benchmark Interest Rate for Hedge Accounting Purposes," which expands the list of United States (U.S.) benchmark interest rates permitted in the application of hedge accounting. This standard allows the use of the Overnight Index Swap (OIS) Rate based on the Secured Overnight Financing Rate (SOFR) as a U.S. benchmark interest rate for hedge accounting purposes. The standard is effective for interim and annual periods beginning after December 15, 2018. The Partnership does not expect the adoption of this standard to have material impact on our Consolidated Financial Statements and related disclosures.

Collaborative Arrangements

In November 2018, the FASB issued ASU No. 2018-18, "Collaborative Arrangements (Topic 808): Clarifying the Interaction between Topic 808 and Topic 606." This standard resolves the diversity in practice concerning the manner in which entities account for transactions on the basis of their view of the economics of the collaborative arrangement. The amendments (1) clarify that certain transactions between collaborative participants should be accounted for as revenue under topic 606 when the collaborative participant is a customer in the context of the unit of account; (2) add unit-of-account guidance in Topic 808 to align with the guidance in Topic 606; and (3) clarify that in a transaction that is not directly related to sales to third parties, presenting the transaction as revenue would be precluded if the collaborative participant counterparty was not a customer. The standard is effective for interim and annual periods beginning after December 15, 2019. The Partnership does not expect the adoption of this standard to have a material impact on our Consolidated Financial Statements and related disclosures.

(3) Revenues

The Partnership adopted ASU No. 2014-09, "Revenue from Contracts with Customers" (ASC 606) on January 1, 2018 using the modified retrospective method. Upon adoption, the Partnership did not recognize a material cumulative adjustment to Partners' Equity and there were no material changes in the timing of revenue recognition or our accounting policies. The Partnership has applied the standard to only contracts that were not expired as of January 1, 2018.

The following tables disaggregate total revenues from contracts with customers by major source and the gain on derivative activity for the year ended December 31, 2018.

	Year Ended December 31, 2018			
	Gathering and Processing	Transportation and Storage	Eliminations	Total
	(In millions)			
Revenues:				
Product sales:				
Natural gas	$ 480	$ 590	$ (506)	$ 564
Natural gas liquids	1,405	30	(30)	1,405
Condensate	126	—	—	126
Total revenues from natural gas, natural gas liquids, and condensate	2,011	620	(536)	2,095
Gain on derivative activity	5	5	1	11
Total Product sales	$ 2,016	$ 625	$ (535)	$ 2,106
Service revenues:				
Demand revenues	$ 252	$ 472	$ —	$ 724
Volume-dependent revenues	550	65	(14)	601
Total Service revenues	$ 802	$ 537	$ (14)	$ 1,325
Total Revenues	$ 2,818	$ 1,162	$ (549)	$ 3,431

Product Sales

Natural Gas, NGLs or Condensate

We deliver natural gas, NGLs and condensate to purchasers at contractually agreed-upon delivery points at which the purchaser takes custody, title, and risk of loss of the commodity. We recognize revenue when control transfers to the purchaser at the delivery point based on the contractually agreed upon fixed or index-based price received.

Gain (Loss) on Derivative Activity

Included in Product sales are gains and losses on natural gas, natural gas liquids, and crude oil (for condensate) derivatives that are accounted for under guidance in ASC 815. See Note 12 for further discussion of our derivative and hedging activity.

Service Revenues

Service revenues include demand revenues and volume-dependent revenues, both of which include contracts with customers that may contain performance obligations that are settled over time. For these types of contracts with customers, service revenue is recognized when the right to invoice has been met, which is in accordance with our election to use the right to invoice practical expedient.

Demand revenues

Our demand revenue arrangements are generally structured in one of the following ways:

- Under a firm arrangement, a customer agrees to pay a fixed fee for a contractually agreed upon pipeline or storage capacity, which results in performance obligations for each individual period of reservation. Once the services have been completed, or the customer no longer has access to the contracted capacity, revenue is recognized.
- Under a minimum volume commitment arrangement, a customer agrees to pay the contractually agreed upon gathering, compressing and treating fees for a minimum volume of natural gas or crude oil irrespective of whether or not the minimum volume of natural gas or crude oil is delivered, which results in performance obligations for each individual unit of volume. If the actual volumes exceed the minimum volume of natural gas or crude oil, the customer pays the contractually agreed upon gathering, compressing and treating fees for the excess volumes in

addition to the fees paid for the minimum volume of natural gas or crude oil. Certain of our contracts provide our customers the option to elect to pay a higher gathering fee over the remaining term of the contract in lieu of making a contractually agreed upon shortfall payment. Once the services have been completed, or the customer no longer has the ability to utilize the services, the performance obligation is met, and revenue is recognized. In addition, when certain minimum volume commitment fee arrangements include commitments of one year or more, significant judgment is used in interim commitment periods in which a customer's actual volumes are deficient in relation to the minimum volume commitment. Revenue is recognized in proportion to the pattern of past performance exercised by the customer or when the likelihood of the customer meeting the minimum volume commitment becomes remote.

Volume-dependent revenues

Our volume-dependent revenues primarily consist of gathering, compressing, treating, processing, transportation or storage services fees on contracts that exceed their contractually committed volume or do not have firm arrangements or minimum volume commitment arrangements. These fees are dependent on throughput by third party customers, which results in performance obligations for each individual unit of volume and revenue is recognized as the service is performed. Our other fee revenue arrangements have pricing terms that are generally structured in one of the following ways: (1) Contractually agreed upon monetary fee for service or (2) contractually agreed upon consideration received in the form of natural gas or natural gas liquids, which are valued at the current month index-based price, which approximates fair value.

Accounts Receivable

Payments for all types of revenues are typically received within 30 days of invoice. Invoices for all revenue types are sent on at least a monthly basis, except for the shortfall provisions under certain minimum volume commitment arrangements, which are typically invoiced annually. Accounts receivable includes accrued revenues associated with certain minimum volume commitments that will be invoiced at the conclusion of the measurement period specified under the respective contracts.

	December 31, 2018	January 1, 2018
	(In millions)	
Accounts Receivable:		
Customers	$ 297	$ 265
Contract assets [(1)]	6	27
Non-customers	6	3
Total Accounts Receivable [(2)]	$ 309	$ 295

(1) Contract assets reflected in Total Accounts Receivable include accrued minimum volume commitments. Contract assets decreased $21 million compared to January 1, 2018 due to increased throughput on certain minimum volume commitment arrangements resulting in lower recognized contract assets as of December 31, 2018. Total Accounts Receivable does not include $3 million of contract assets related to firm transportation contracts with tiered rates, which are reflected in Other Assets.
(2) Total Accounts Receivable includes Accounts receivables, net of allowance for doubtful accounts and Accounts receivable—affiliated companies.

Contract Liabilities

Our contract liabilities primarily consist of the following prepayments received from customers for which the good or service has not yet been provided in connection with the prepayment:

- Under certain firm arrangements, customers pay their demand fee prior to the month of contracted capacity. These fees are applied to the subsequent month's activity and are included in other current liabilities on the Consolidated Balance Sheets.
- Under certain demand and volume dependent arrangements, customers make contributions of aid in construction payments. For payments that are related to contracts under ASC 606, the payment is deferred and amortized over the life of the associated contract and the unamortized balance is included in other current or long-term liabilities on the Consolidated Balance Sheets.

The table below summarizes the change in the contract liabilities for the year ended December 31, 2018:

	December 31, 2018	December 31, 2017	Amounts recognized in revenues
		(In millions)	
Deferred revenues	$ 48	$ 34	$ 19

The table below summarizes the timing of recognition of these contract liabilities as of December 31, 2018:

	2019	2020	2021	2022	2023 and After
			(In millions)		
Deferred revenues	$ 25	$ 5	$ 5	$ 5	$ 8

Remaining Performance Obligations

Our remaining performance obligations consist primarily of firm arrangements and minimum volume commitment arrangements. Upon completion of the performance obligations associated with these arrangements, customers are invoiced and revenue is recognized as Service revenues in the Consolidated Statements of Income.

The table below summarizes the timing of recognition of the remaining performance obligations as of December 31, 2018:

	2019	2020	2021	2022	2023 and After
			(In millions)		
Transportation and Storage	$ 438	$ 319	$ 175	$ 133	$ 745
Gathering and Processing	280	164	136	138	461
Total remaining performance obligations	$ 718	$ 483	$ 311	$ 271	$ 1,206

Impact of Adoption

Upon adoption of ASC 606, the recognition of revenues for certain contractual arrangements was impacted as follows:

- Natural gas and natural gas liquids purchase arrangements - For certain arrangements within our gathering and processing segment, the Partnership purchases and controls the entire hydrocarbon stream at the point of receipt. As of January 1, 2018, these arrangements are considered supplier contracts rather than contracts with customers. Therefore, beginning January 1, 2018, the gathering and processing fees for these arrangements that were previously recognized as Service revenues under ASC 605 are recognized as reductions to Cost of natural gas and natural gas liquids.
- Percent-of-proceeds and percent-of-liquids processing arrangements - Under percent-of-proceeds and percent-of-liquids arrangements within our gathering and processing segment, the Partnership has previously recognized the value of natural gas and natural gas liquids received in our purchase cost within Cost of natural gas and natural gas liquids. As of January 1, 2018, the Partnership recognizes the value of the natural gas and NGLs received as Service revenues and as an increase to Cost of natural gas and natural gas liquids when the natural gas or NGLs are sold and Product sales are recognized.
- Keep-whole arrangements - Under keep-whole arrangements within our gathering and processing segment, the Partnership has previously recognized the value of NGLs received in Product sales and the value of the thermally equivalent quantity of natural gas provided in our purchase cost within Cost of natural gas and natural gas liquids. As of January 1, 2018, the Partnership recognizes the value of the NGLs received less the value of the thermally equivalent volume of natural gas provided as Service revenues and as an increase to Cost of natural gas and natural gas liquids when the NGLs are sold and Product sales are recognized.
- Fixed fuel arrangements - Under certain gathering arrangements within our gathering and processing segment as well as under certain transportation arrangements within our transportation and storage segment we receive a fixed amount of fuel regardless of actual fuel usage. Previously, revenue for fuel in excess of actual usage was recognized when such fuel was received, and additional revenue was recognized when such fuel was sold. As of January 1, 2018, fuel in excess of actual usage is treated as a byproduct obtained through the fulfillment of a contract, and

the Partnership will recognize revenue at the time the excess fuel is sold. This results in a reduction of Product sales and a corresponding reduction in Cost of natural gas and natural gas liquids.

- Natural gas and natural gas liquids sales arrangements - For certain arrangements within our gathering and processing segment, the Partnership sells the entire hydrocarbon stream at the point of delivery to a third-party processing facility. As of January 1, 2018, these arrangements are considered sales once control has transferred to the third-party processing facility. Therefore, beginning January 1, 2018, the costs and fees for these arrangements that were previously recognized as a component of cost of gas and natural gas liquids, are recognized as reductions to the transaction price under ASC 606.

Below is a summary of the impact of the changes on revenues as it relates to the year ended December 31, 2018:

	Year Ended December 31, 2018		
	Under ASC 606	Under ASC 605	Increase/(Decrease)
		(In millions)	
Revenues:			
Product sales:			
Natural gas	$ 564	$ 635	$ (71)
Natural gas liquids	1,405	1,434	(29)
Condensate	126	126	—
Total revenues from natural gas, natural gas liquids, and condensate	2,095	2,195	(100)
Gain on derivative activity	11	11	—
Total Product sales	$ 2,106	$ 2,206	$ (100)
Service revenues:			
Demand revenues	$ 724	$ 724	$ —
Volume-dependent revenues	601	577	24
Total Service revenues	$ 1,325	$ 1,301	$ 24
Total Revenues	$ 3,431	$ 3,507	$ (76)

As described above, each of the identified increases/(decreases) in revenue resulted in a corresponding change in the Cost of natural gas and natural gas liquids.

(4) Acquisitions

Velocity Holdings, LLC Acquisition

On November 1, 2018, the Partnership acquired all of the equity interests in Velocity Holdings, LLC, now EOCS, which owns and operates a crude oil and condensate gathering system in the SCOOP and STACK plays of the Anadarko Basin, for approximately $444 million in cash, subject to certain customary working capital adjustments. The acquisition was accounted for as a business combination and was funded with borrowings under the commercial paper program. During the fourth quarter of 2018, the Partnership finalized the purchase price allocation as of November 1, 2018.

The following table presents the fair value of the identified assets acquired and liabilities assumed at the acquisition date:

Purchase price allocation (in millions):		
Assets acquired:		
Cash	$	1
Accounts receivable		3
Property, plant and equipment		124
Intangibles		259
Goodwill		86
Liabilities assumed:		
Current liabilities		1
Less: Noncontrolling interest at fair value		28
Total identifiable net assets	$	444

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 greater operating leverage in the Anadarko Basin and is allocated to the gathering and processing segment. Included within the acquisition was 60% of a 26-mile pipeline system joint venture with a third party which owns and operates a refinery connected to the EOCS system. This joint venture's financials have been consolidated within the Partnership's financial statements resulting in $28 million in non-controlling interest. The Partnership incurred approximately $6 million of acquisition costs associated with this transaction, which are included in General and administrative expense in the Consolidated Statements of Income. The Partnership determined not to include pro forma consolidated financial statements for the periods presented as the impact would not be material.

Align Midstream, LLC Acquisition

On October 4, 2017, the Partnership acquired all of the equity interests in Align Midstream, LLC, now Enable Texola Gathering and Processing, LLC, a midstream service provider with natural gas gathering and processing facilities in the Cotton Valley and Haynesville plays of the Ark-La-Tex Basin, for approximately $298 million in cash. The acquisition was accounted for as a business combination and funded with borrowings under the Revolving Credit Facility. During the fourth quarter of 2017, the Partnership finalized the purchase price allocation as of October 4, 2017.

The following table presents the fair value of the identified assets acquired and liabilities assumed at the acquisition date:

Purchase price allocation (in millions):		
Assets acquired:		
Accounts receivable	$	5
Property, plant and equipment		111
Intangibles		176
Goodwill		12
Liabilities assumed:		
Current liabilities		6
Total identifiable net assets	$	298

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 10 years. Goodwill recognized from the acquisition primarily relates to greater operating leverage in the Ark-La-Tex Basin and is allocated to the gathering and processing segment. The Partnership incurred approximately $2 million of acquisition costs associated with this transaction, which are included in General and administrative expense in the Consolidated Statements of Income. The Partnership determined not to include pro forma consolidated financial statements for the periods presented as the impact would not be material.

(5) Earnings Per Limited Partner Unit

Basic and diluted earnings per limited partner unit is calculated by dividing net income allocable to common and subordinated unitholders by the weighted average number of common and subordinated 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 18 was $0.01 per unit during the year ended December 31, 2018 and less than $0.01 per unit during the years ended December 31, 2017 and 2016.

The following table illustrates the Partnership's calculation of earnings per unit for common and subordinated units:

	Year Ended December 31,		
	2018	2017	2016
	(In millions, except per unit data)		
Net income	$ 523	$ 437	$ 313
Net income attributable to noncontrolling interests	2	1	1
Series A Preferred Unit distributions	36	36	22
General partner interest in net income	—	—	—
Net income available to common and subordinated unitholders	$ 485	$ 400	$ 290
Net income allocable to common units	$ 485	$ 273	$ 148
Net income allocable to subordinated units	—	127	142
Net income available to common and subordinated unitholders	$ 485	$ 400	$ 290
Net income allocable to common units	$ 485	$ 273	$ 148
Dilutive effect of Series A Preferred Unit distribution	—	—	—
Diluted net income allocable to common units	485	273	148
Diluted net income allocable to subordinated units	—	127	142
Total	$ 485	$ 400	$ 290
Basic weighted average number of outstanding			
Common units (1)	434	296	216
Subordinated units	—	137	208
Total	434	433	424
Basic earnings per unit			
Common units	$ 1.12	$ 0.92	$ 0.69
Subordinated units	$ —	$ 0.93	$ 0.68
Basic weighted average number of outstanding common units	434	296	216
Dilutive effect of Series A Preferred Units	—	—	—
Dilutive effect of performance units	2	1	—
Diluted weighted average number of outstanding common units	436	297	216
Diluted weighted average number of outstanding subordinated units	—	137	208
Total	436	434	424
Diluted earnings per unit			
Common units	$ 1.11	$ 0.92	$ 0.69
Subordinated units	$ —	$ 0.93	$ 0.68

(1) Basic weighted average number of outstanding common units for the year ended December 31, 2018 includes approximately one million time-based phantom units.

See Note 6 for discussion of the expiration of the subordination period.

(6) Enable Midstream Partners, LP Partners' Equity

The Partnership Agreement requires that, within 60 days subsequent to the end of each quarter, the Partnership distribute all of its available cash (as defined in the Partnership Agreement) to unitholders of record on the applicable record date.

The Partnership paid or has authorized payment of the following cash distributions to common and subordinated unitholders, as applicable, during 2018, 2017 and 2016 (in millions, except for per unit amounts):

Quarter Ended	Record Date	Payment Date	Per Unit Distribution	Total Cash Distribution
2018				
December 31, 2018 [1]	February 19, 2019	February 26, 2019	$ 0.318	$ 138
September 30, 2018	November 16, 2018	November 29, 2018	$ 0.318	$ 138
June 30, 2018	August 21, 2018	August 28, 2018	$ 0.318	$ 138
March 31, 2018	May 22, 2018	May 29, 2018	$ 0.318	$ 138
2017				
December 31, 2017	February 20, 2018	February 27, 2018	$ 0.318	$ 138
September 30, 2017	November 14, 2017	November 21, 2017	$ 0.318	$ 138
June 30, 2017	August 22, 2017	August 29, 2017	$ 0.318	$ 138
March 31, 2017	May 23, 2017	May 30, 2017	$ 0.318	$ 137
2016				
December 31, 2016	February 21, 2017	February 28, 2017	$ 0.318	$ 137
September 30, 2016	November 14, 2016	November 22, 2016	$ 0.318	$ 134
June 30, 2016	August 16, 2016	August 23, 2016	$ 0.318	$ 134
March 31, 2016	May 6, 2016	May 13, 2016	$ 0.318	$ 134

(1) The board of directors of Enable GP declared this $0.318 per common unit cash distribution on February 8, 2019, to be paid on February 26, 2019, to common unitholders of record at the close of business on February 19, 2019.

The Partnership paid or has authorized payment of the following cash distributions to holders of the Series A Preferred Units during 2018, 2017, and 2016 (in millions, except for per unit amounts):

Quarter Ended	Record Date	Payment Date	Per Unit Distribution		Total Cash Distribution	
2018						
December 31, 2018 [(1)]	February 8, 2019	February 14, 2019	$	0.625	$	9
September 30, 2018	November 6, 2018	November 14, 2018	$	0.625	$	9
June 30, 2018	August 1, 2018	August 14, 2018	$	0.625	$	9
March 31, 2018	May 1, 2018	May 15, 2018	$	0.625	$	9
2017						
December 31, 2017	February 9, 2018	February 15, 2018	$	0.625	$	9
September 30, 2017	October 31, 2017	November 14, 2017	$	0.625	$	9
June 30, 2017	July 31, 2017	August 14, 2017	$	0.625	$	9
March 31, 2017	May 2, 2017	May 12, 2017	$	0.625	$	9
2016						
December 31, 2016	February 10, 2017	February 15, 2017	$	0.625	$	9
September 30, 2016	November 1, 2016	November 14, 2016	$	0.625	$	9
June 30, 2016	August 2, 2016	August 12, 2016	$	0.625	$	9
March 31, 2016 [(2)]	May 6, 2016	May 13, 2016	$	0.2917	$	4

(1) The board of directors of Enable GP declared this $0.625 per Series A Preferred Unit cash distribution on February 8, 2019, which was paid on February 14, 2019 to Series A Preferred unitholders of record at the close of business on February 8, 2019.

(2) The prorated quarterly distribution for the Series A Preferred Units is for a partial period beginning on February 18, 2016, and ending on March 31, 2016, which equates to $0.625 per unit on a full-quarter basis or $2.50 per unit on an annualized basis.

General Partner Interest and Incentive Distribution Rights

Enable GP owns a non-economic general partner interest in the Partnership and, except as provided below with respect to incentive distribution rights, 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 (as defined in the Partnership Agreement) 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 that they own.

Expiration of Subordination Period

Prior to the expiration of the subordination period, CenterPoint Energy and OGE Energy held 139,704,916 and 68,150,514 subordinated units, respectively. The financial tests required for conversion of all subordinated units were met and the 207,855,430 outstanding subordinated units converted into common units on a one-for-one basis on August 30, 2017. The conversion of the subordinated units did not change the aggregate amount of outstanding units, and the conversion of the subordinated units did not impact the amount of cash available for distribution by the Partnership.

Series A Preferred Units

On February 18, 2016, the Partnership completed the private placement of 14,520,000 Series A Preferred Units representing limited partner interests in the Partnership for a cash purchase price of $25.00 per Series A Preferred Unit, resulting in proceeds of $362 million, net of issuance costs. The Partnership incurred approximately $1 million of expenses related to the offering, which is shown as an offset to the proceeds. In connection with the closing of the private placement, the Partnership redeemed approximately $363 million of notes scheduled to mature in 2017 payable to a wholly-owned subsidiary of CenterPoint Energy.

Pursuant to the Partnership Agreement, the Series A Preferred Units:

- rank senior to the Partnership’s common units with respect to the payment of distributions and distribution of assets upon liquidation, dissolution and winding up;
- have no stated maturity;

- are not subject to any sinking fund; and
- will remain outstanding indefinitely unless repurchased or redeemed by the Partnership or converted into its common units in connection with a change of control.

Holders of the Series A Preferred Units receive a quarterly cash distribution on a non-cumulative basis if and when declared by the General Partner, and subject to certain adjustments, equal to an annual rate of: 10% on the stated liquidation preference of $25.00 from the date of original issue to, but not including, the five year anniversary of the original issue date; and thereafter a percentage of the stated liquidation preference equal to the sum of the three-month LIBOR plus 8.5%.

At any time on or after five years after the original issue date, the Partnership may redeem the Series A Preferred Units, in whole or in part, from any source of funds legally available for such purpose, by paying $25.50 per unit plus an amount equal to all accumulated and unpaid distributions thereon to the date of redemption, whether or not declared. In addition, the Partnership (or a third-party with its prior written consent) may redeem the Series A Preferred Units following certain changes in the methodology employed by ratings agencies, changes of control or fundamental transactions as set forth in the Partnership Agreement. If, upon a change of control or certain fundamental transactions, the Partnership (or a third-party with its prior written consent) does not exercise this option, then the holders of the Series A Preferred Units have the option to convert the Series A Preferred Units into a number of common units per Series A Preferred Unit as set forth in the Partnership Agreement. The Series A Preferred Units are also required to be redeemed in certain circumstances if they are not eligible for trading on the New York Stock Exchange.

Holders of Series A Preferred Units have no voting rights except for limited voting rights with respect to potential amendments to the Partnership Agreement that have a material adverse effect on the existing terms of the Series A Preferred Units, the issuance by the Partnership of certain securities, approval of certain fundamental transactions and as required by law.

Upon the transfer of any Series A Preferred Unit to a non-affiliate of CenterPoint Energy, the Series A Preferred Units will automatically convert into a new series of preferred units (the Series B Preferred Units) on the later of the date of transfer and the second anniversary of the date of issue. The Series B Preferred Units will have the same terms as the Series A Preferred Units except that unpaid distributions on the Series B Preferred Units will accrue on a cumulative basis until paid.

On February 18, 2016, the Partnership entered into a registration rights agreement with CenterPoint Energy, pursuant to which, among other things, the Partnership gave CenterPoint Energy certain rights to require the Partnership to file and maintain a registration statement with respect to the resale of the Series A Preferred Units and any other series of preferred units or common units representing limited partner interests in the Partnership that are issuable upon conversion of the Series A Preferred Units.

ATM Program

On May 12, 2017, the Partnership entered into an ATM Equity Offering Sales Agreement in connection with an at-the-market program (the “ATM Program”). Pursuant to the ATM Program, the Partnership may issue and sell common units having an aggregate offering price of up to $200 million, by sales methods and at prices determined by market conditions and other factors at the time of our offerings. The Partnership has no obligation to sell any common units under the ATM Program and the Partnership may suspend sales under the ATM Program at any time. For the year ended December 31, 2018, the Partnership issued 140,920 common units under the ATM Program, which generated proceeds of approximately $2 million (net of approximately $25,000 of commissions). For the year ended December 31, 2017, the Partnership issued 18,500 units under the ATM Program, which generated proceeds of approximately $303,000 (net of approximately $3,000 of commissions). The proceeds were used for general partnership purposes. As of December 31, 2018, $197 million of common units remained available for issuance through the ATM Program.

2016 Equity Issuance

On November 29, 2016, the Partnership closed a public offering of 10,000,000 common units at a price to the public of $14.00 per common unit. In connection with the offering, the Partnership, the underwriters and an affiliate of ArcLight entered into an underwriting agreement that provided an option for the underwriters to purchase up to an additional 1,500,000 common units, with 75,719 common units to be sold by the Partnership and 1,424,281 to be sold by the affiliate of ArcLight. The underwriters exercised the option to purchase all of the additional common units, and the Partnership received proceeds (net of underwriting discounts, structuring fees and offering expenses) of $137 million from the offering.

(7) Property, Plant and Equipment

Property, plant and equipment includes the following:

	Weighted Average Useful Lives (Years)	December 31, 2018	December 31, 2017
		(In millions)	
Property, plant and equipment, gross:			
Gathering and Processing	37	$ 8,011	$ 7,322
Transportation and Storage	36	4,740	4,538
Construction work-in-progress		148	219
Total		$ 12,899	$ 12,079
Accumulated depreciation:			
Gathering and Processing		1,063	865
Transportation and Storage		965	859
Total accumulated depreciation		2,028	1,724
Property, plant and equipment, net		$ 10,871	$ 10,355

The Partnership recorded depreciation expense of $351 million, $335 million and $311 million during the years ended December 31, 2018, 2017 and 2016, respectively.

(8) Intangible Assets, Net

The Partnership has intangible assets associated with customer relationships related to the acquisitions of Enogex LLC, Monarch Natural Gas, LLC, Align Midstream, LLC and Velocity Holdings, LLC as follows:

	December 31, 2018	December 31, 2017
	(In millions)	
Customer relationships:		
Total intangible assets [(1)]	$ 840	$ 581
Accumulated amortization	177	130
Net intangible assets	$ 663	$ 451

(1) See Note 4 for discussion of the acquisition of Velocity Holdings, LLC and Align Midstream, LLC during the years ended December 31, 2018 and 2017, respectively.

Intangible assets related to customer relationships have a weighted average useful life of 14 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 $47 million, $31 million and $27 million during the years ended December 31, 2018, 2017 and 2016, respectively. The following table summarizes the Partnership's expected amortization of intangible assets for each of the next five years:

	2019	2020	2021	2022	2023
			(In millions)		
Expected amortization of intangible assets	$ 62	$ 62	$ 62	$ 62	$ 62

(9) Goodwill

In the fourth quarter of 2017, as a result of the acquisition of Align, the Partnership recorded $12 million of goodwill, included in the gathering and processing reportable segment. In the fourth quarter of 2018, as a result of the acquisition of Velocity, the Partnership recorded $86 million of goodwill, included in the gathering and processing reportable segment.

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 31, 2016	$ —	$ —	$ —
Align Midstream, LLC Acquisition [1]	12	—	12
Balance as of December 31, 2017	$ 12	$ —	$ 12
Velocity Holdings, LLC Acquisition [1]	86	—	86
Balance as of December 31, 2018	$ 98	$ —	$ 98

(1) See Note 4 for further discussion.

(10) Investment in Equity Method Affiliate

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.

SESH is owned 50% by Enbridge, Inc and 50% by the Partnership for the years ended December 31, 2018 and 2017. 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, Enbridge Inc. may, under certain circumstances, have the right to purchase our interest in SESH at fair market value, subject to certain exceptions.

The Partnership shares operations of SESH with Enbridge Inc. 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, 2018, 2017 and 2016, the Partnership billed SESH $18 million, $17 million and $13 million, respectively, associated with these service agreements.

The Partnership includes equity in earnings of equity method affiliate under the Other Income (Expense) caption in the Consolidated Statements of Income for the years ended December 31, 2018, 2017 and 2016.

SESH:

	Year Ended December 31,		
	2018	2017	2016
		(In millions)	
Equity in Earnings of Equity Method Affiliate	$ 26	$ 28	$ 28
Distributions from Equity Method Affiliate [1]	33	33	43

(1) Distributions from equity method affiliate includes a $26 million, $28 million and $28 million return on investment and a $7 million, $5 million and $15 million return of investment for the years ended December 31, 2018, 2017 and 2016, respectively.

Summarized financial information of SESH:

	December 31, 2018	December 31, 2017
	(In millions)	
Balance Sheet Data:		
Current assets	$ 30	$ 32
Property, plant and equipment, net	1,078	1,093
Total assets	$ 1,108	$ 1,125
Current liabilities	$ 13	$ 14
Long-term debt	397	397
Members’ equity	698	714
Total liabilities and members’ equity	$ 1,108	$ 1,125
Reconciliation:		
Investment in SESH	$ 317	$ 324
Less: Capitalized interest on investment in SESH	(1)	(1)
Add: Basis differential, net of amortization	33	34
The Partnership’s share of members’ equity	$ 349	$ 357

	Year Ended December 31, 2018	Year Ended December 31, 2017	Year Ended December 31, 2016
	(In millions)		
Income Statement Data:			
Revenues	$ 112	$ 113	$ 115
Operating income	$ 67	$ 72	$ 73
Net income	$ 50	$ 54	$ 55

(11) Debt

The following table presents the Partnership’s outstanding debt as of December 31, 2018 and 2017.

	December 31, 2018			December 31, 2017		
	Outstanding Principal	Premium (Discount)[1]	Total Debt	Outstanding Principal	Premium (Discount)[1]	Total Debt
			(In millions)			
Commercial Paper	$ 649	$ —	$ 649	$ 405	$ —	$ 405
Revolving Credit Facility	250	—	250	—	—	—
2015 Term Loan Agreement	—	—	—	450	—	450
2019 Notes	500	—	500	500	—	500
2024 Notes	600	—	600	600	—	600
2027 Notes	700	(2)	698	700	(3)	697
2028 Notes	800	(6)	794	—	—	—
2044 Notes	550	—	550	550	—	550
EOIT Senior Notes	250	7	257	250	13	263
Total debt	$ 4,299	$ (1)	$ 4,298	$ 3,455	$ 10	$ 3,465
Less: Short-term debt [2]			649			405
Less: Current portion of long-term debt [3]			500			450
Less: Unamortized debt expense [4]			20			15
Total long-term debt			$ 3,129			$ 2,595

(1) Unamortized premium (discount) on long-term debt is amortized over the life of the respective debt.
(2) Short-term debt includes $649 million and $405 million of commercial paper outstanding as of December 31, 2018 and 2017, respectively.
(3) As of December 31, 2018, Current portion of long-term debt includes the $500 million outstanding balance of the 2019 Notes due May 15, 2019. At December 31, 2017, Current portion of long-term debt included the $450 million outstanding balance of the 2015 Term Loan Agreement which the Partnership repaid in May 2018.
(4) As of December 31, 2018 and 2017, there was an additional $6 million and $3 million, respectively, of unamortized debt expense related to the Revolving Credit Facility included in Other long-term assets, not included above. Unamortized debt expense is amortized over the life of the respective debt.

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

2019	$ 1,149
2020	250
2021	—
2022	—
2023	250
Thereafter	$ 2,650

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 were $649 million and $405 million outstanding under our commercial paper program at December 31, 2018 and December 31, 2017, respectively. The weighted average interest rate for the outstanding commercial paper was 3.40% as of December 31, 2018.

Revolving Credit Facility

On April 6, 2018, the Partnership amended and restated its Revolving Credit Facility. As amended and restated, the Revolving Credit Facility is a $1.75 billion, five-year senior unsecured revolving credit facility, which under certain circumstances may be increased from time to time up to an additional $875 million, in aggregate. The Revolving Credit Facility is scheduled to mature on April 6, 2023, subject to an extension option, which may be exercised two times to extend the term of the Revolving Credit facility, in each case, for an additional one-year term. As of December 31, 2018, there were $250 million principal advances and $3 million in letters of credit outstanding under the restated Revolving Credit Facility.

The Revolving Credit Facility provides that outstanding borrowings bear interest at 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, 2018, 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, 2018, 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 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.

2015 Term Loan Agreement

On July 31, 2015, the Partnership entered into a term loan facility, providing for an unsecured three-year $450 million term loan agreement, which was scheduled to mature on July 31, 2018. The 2015 Term Loan Agreement is included as Current portion of long-term debt in the Partnership's Consolidated Balance Sheets as of December 31, 2017. In May 2018, we used a portion of the proceeds from the issuance of the 2028 Notes to repay all amounts outstanding under the 2015 Term Loan Agreement.

Senior Notes

On May 10, 2018, the Partnership completed the public offering of $800 million aggregate principal amount of its 4.95% Senior Notes due 2028. The Partnership received net proceeds of approximately $787 million. The proceeds were used for general partnership purposes, including to repay all amounts outstanding under the 2015 Term Loan Agreement, as well as amounts outstanding under the commercial paper program. The 2028 Notes had an unamortized discount of $6 million and unamortized debt expense of $7 million at December 31, 2018, resulting in an effective interest rate of 5.21% during the year ended December 31, 2018.

In addition to the 2028 Notes, as of December 31, 2018, the Partnership's debt included the 2019 Notes, 2024 Notes, 2027 Notes and 2044 Notes, which had $2 million of unamortized discount and $13 million of unamortized debt expense at December 31, 2018, resulting in effective interest rates of 2.57%, 4.02%, 4.58% and 5.08%, respectively, during the year ended December 31, 2018.

The indenture governing the 2019 Notes, 2024 Notes, 2027 Notes, 2028 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, 2018, the Partnership's debt included EOIT's Senior Notes. The EOIT Senior Notes had $7 million of unamortized premium at December 31, 2018, resulting in an effective interest rate of 3.83% during the year ended December 31,

2018. 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.

As of December 31, 2018, the Partnership and EOIT were in compliance with all of their debt agreements, including financial covenants.

(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 oil futures, swaps and swaptions are used to manage the Partnership's NGL and condensate exposure associated with its processing agreements;
- natural gas futures and swaps, natural gas options, natural gas swaptions and natural gas commodity purchases and sales are used to manage the Partnership's natural gas exposure associated with its gathering, processing, transportation and storage assets, 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 are recorded as Other Assets or Liabilities in the Consolidated Balance Sheets at fair value on a net basis with such amounts classified as current or long-term based on their anticipated settlement.

As of December 31, 2018 and 2017, the Partnership had no derivative instruments that were designated as cash flow or fair value hedges for accounting purposes.

Credit Risk

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, 2018 and 2017, the Partnership had the following derivative instruments that were not designated as hedging instruments for accounting purposes:

	December 31, 2018		December 31, 2017	
	Gross Notional Volume			
	Purchases	Sales	Purchases	Sales
Natural gas— TBtu (1)				
Financial fixed futures/swaps	16	28	17	13
Financial basis futures/swaps	18	29	17	17
Financial swaptions (3)	—	1	—	—
Physical purchases/sales	—	11	1	37
Crude oil (for condensate)— MBbl (2)				
Financial futures/swaps	—	945	—	564
Financial swaptions (3)	—	30	—	—
Natural gas liquids— MBbl (4)				
Financial futures/swaps	270	2,535	—	1,615

(1) As of December 31, 2018, 74.0% of the natural gas contracts had durations of one year or less, 24.2% had durations of more than one year and less than two years and 1.8% had durations of more than two years. As of December 31, 2017, 67.7% of the natural gas contracts had durations of one year or less, 16.1% had durations of more than one year and less than two years and 16.2% had durations of more than two years.

(2) As of December 31, 2018, 76.9% of the crude oil (for condensate) contracts had durations of one year or less and 23.1% had durations of more than one year and less than two years. As of December 31, 2017, 100% of the crude oil (for condensate) contracts had durations of one year or less.

(3) The notional value contains a combined derivative instrument consisting of a fixed price swap and a sold option, which gives the counterparties the right, but not the obligation, to increase the notional quantity hedged under the fixed price swap until the option expiration date. The notional volume represents the volume prior to option exercise.

(4) As of December 31, 2018, 86.1% of the natural gas liquids contracts had durations of one year or less and 13.9% had durations of more than one year and less than two years. As of December 31, 2017, 100% of the natural gas liquid contracts had 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, 2018 and 2017 that were not designated as hedging instruments for accounting purposes are as follows:

Instrument	Balance Sheet Location	December 31, 2018 Fair Value Assets	December 31, 2018 Fair Value Liabilities	December 31, 2017 Fair Value Assets	December 31, 2017 Fair Value Liabilities
		(In millions)			
Natural gas					
Financial futures/swaps	Other Current	$ 3	$ 5	$ 5	$ 2
Financial futures/swaps	Other	—	2	—	2
Physical purchases/sales	Other Current	3	—	1	—
Physical purchases/sales	Other	4	—	2	—
Crude oil (for condensate)					
Financial futures/swaps	Other Current	9	3	—	4
Financial futures/swaps	Other	2	—	—	—
Financial swaptions	Other	—	—	—	—
Natural gas liquids					
Financial futures/swaps	Other Current	10	1	1	5
Financial futures/swaps	Other	2	—	—	—
Total gross derivatives [(1)]		$ 33	$ 11	$ 9	$ 13

(1) See Note 13 for a reconciliation of the Partnership's total derivatives fair value to the Partnership's Consolidated Balance Sheets as of December 31, 2018 and 2017.

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, 2018, 2017 and 2016:

	Amounts Recognized in Income Year Ended December 31, 2018	2017	2016
	(In millions)		
Natural Gas			
Financial futures/swaps (losses) gains	$ (8)	$ 20	$ (19)
Physical purchases/sales gains (losses)	7	9	(7)
Crude oil (for condensate)			
Financial futures/swaps gains (losses)	6	(1)	(4)
Financial swaptions gains (losses)	—	—	—
Natural gas liquids			
Financial futures/swaps gains (losses)	6	(9)	(13)
Total	$ 11	$ 19	$ (43)

For derivatives not designated as hedges in the tables above, amounts recognized in income for the years ended December 31, 2018, 2017 and 2016, if any, are reported in Product sales.

The following table presents the components of gain (loss) on derivative activity in the Partnership's Consolidated Statements of Income for the years ended December 31, 2018, 2017 and 2016:

	Year Ended December 31,		
	2018	2017	2016
		(In millions)	
Change in fair value of derivatives	$ 26	$ 28	$ (60)
Realized (loss) gain on derivatives	(15)	(9)	17
Gain (loss) on derivative activity	$ 11	$ 19	$ (43)

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, the Partnership could be required to provide additional credit assurances which could include letters or credit or cash collateral to satisfy its obligation under its financial and physical contracts relating to derivative instruments that are in a net liability position. As of December 31, 2018, under these obligations, the Partnership has posted no cash collateral related to NGL swaps and crude oil swaps and swaptions and no additional collateral would be required to be posted by the Partnership in the event of a credit ratings downgrade to a below investment grade rating.

(13) 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 either NYMEX or ICE and settled through either a NYMEX or ICE 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 generally include over-the-counter natural gas swaps, natural gas swaptions, natural gas basis swaps and natural gas purchase and sales transactions in markets such that the pricing is closely related to the NYMEX or the ICE pricing, and over-the-counter WTI crude oil swaps and swaptions 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, ICE or WTI published market prices, independent broker pricing data or broker/dealer valuations. The valuations of derivatives with pricing based on NYMEX or ICE published market prices may be considered Level 1 if they are settled through a NYMEX or ICE clearing broker account with daily margining. Over-the-counter derivatives with NYMEX, ICE 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. Certain derivatives with option features may be classified as Level 2 if valued using an industry standard Black-Scholes option pricing model that contain observable inputs in the marketplace throughout the term of the derivative instrument. 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. As of December 31, 2018, there were no contracts 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, 2018, all instruments previously classified as Level 3 were transferred to Level 2 as the inputs for these liabilities became observable for classification in Level 2.

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 due to their short-term nature 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, 2018 and 2017:

	December 31, 2018		December 31, 2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Debt				
Revolving Credit Facility (Level 2) (1)	$ 250	$ 250	$ —	$ —
2015 Term Loan Agreement (Level 2)	—	—	450	450
2019 Notes (Level 2)	500	497	500	497
2024 Notes (Level 2)	600	571	600	602
2027 Notes (Level 2)	698	642	697	712
2028 Notes (Level 2)	794	764	—	—
2044 Notes (Level 2)	550	445	550	550
EOIT Senior Notes (Level 2)	257	256	263	265

(1) Borrowing capacity is effectively reduced by our borrowings outstanding under the commercial paper program. $649 million and $405 million of commercial paper was outstanding as of December 31, 2018 and 2017, respectively.

The fair value of the Partnership's Revolving Credit Facility, 2015 Term Loan Agreement, 2019 Notes, 2024 Notes, 2027 Notes, 2028 Notes, 2044 Notes, and EOIT Senior Notes, is based on quoted market prices and estimates of current rates available for similar issues with similar maturities and is classified as Level 2 in the fair value hierarchy.

Non-Financial Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are measured at fair value on a nonrecurring basis; that is, the assets and liabilities are not measured at fair value on an ongoing basis, but are subject to fair value adjustments in certain circumstances (e.g., when there is evidence of impairment).

During the year ended December 31, 2016, the Partnership remeasured the Service Star assets at fair value and reassessed the carrying value of the Service Star business line, a component of the gathering and processing segment that provides measurement and communication services to third parties. The impairment, which impaired substantially all of the remaining net book value of the Service Star business line, was primarily driven by the impact of planned technology changes affecting Service Star. 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 forecasted cash flows and the discount rate. The fair value measurement is based on inputs that are not observable in the market and thus represent level 3 inputs. Applying a discounted cash flow model to the property, plant and equipment and reviewing the associated materials and supplies inventory, during the year ended December 31, 2016, the Partnership recognized a $9 million impairment. The impairment consisted of an $8 million write-down of property, plant and equipment and a $1 million write-down of materials and supplies inventory considered either excess or obsolete.

Based upon review of forecasted undiscounted cash flows as of December 31, 2018, all of the asset groups were considered recoverable. Future price declines, throughput declines, contracted capacity declines, cost increases, regulatory or political environment changes and other changes in market conditions could reduce forecasted undiscounted cash flows.

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, 2018 and 2017:

December 31, 2018	**Commodity Contracts**		**Gas Imbalances (1)**	
	Assets	**Liabilities**	**Assets (2)**	**Liabilities (3)**
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$ 4	$ 9	$ —	$ —
Significant other observable inputs (Level 2)	29	2	18	17
Unobservable inputs (Level 3)	—	—	—	—
Total fair value	33	11	18	17
Netting adjustments	(9)	(9)	—	—
Total	$ 24	$ 2	$ 18	$ 17

December 31, 2017	**Commodity Contracts**		**Gas Imbalances (1)**	
	Assets	**Liabilities**	**Assets (2)**	**Liabilities (3)**
	(In millions)			
Quoted market prices in active market for identical assets (Level 1)	$ 5	$ 3	$ —	$ —
Significant other observable inputs (Level 2)	4	5	27	12
Unobservable inputs (Level 3)	—	5	—	—
Total fair value	9	13	27	12
Netting adjustments	(5)	(5)	—	—
Total	$ 4	$ 8	$ 27	$ 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. There were no netting adjustments as of December 31, 2018 and 2017.

(2) Gas imbalance assets exclude fuel reserves for under retained fuel due from shippers of $11 million and $10 million at December 31, 2018 and 2017, 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 none at December 31, 2018 and 2017, 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 commodity contracts between the periods presented. Transfers out of Level 3 represent liabilities that were previously classified as Level 3 for which the inputs became observable for classification in Level 2. Because the activity and liquidity of commodity markets vary substantially between regions and time periods, the availability of observable inputs for substantially the full term and value of the Partnership's derivative contracts is subject to change.

	Commodity Contracts	
	Natural gas liquids financial futures/swaps	
	(In millions)	
Balance as of December 31, 2016	$	(8)
Losses included in earnings		(9)
Settlements		12
Transfers out of Level 3		—
Balance as of December 31, 2017		(5)
Losses included in earnings		(23)
Settlements		7
Transfers out of Level 3		21
Balance as of December 31, 2018	$	—

(14) Supplemental Disclosure of Cash Flow Information

The following table provides information regarding supplemental cash flow information:

	Year Ended December 31,					
	2018		2017		2016	
	(In millions)					
Supplemental Disclosure of Cash Flow Information:						
Cash Payments:						
Interest, net of capitalized interest	$	148	$	114	$	105
Income taxes, net of refunds		3		—		—
Non-cash transactions:						
Accounts payable related to capital expenditures		54		39		18

The following table reconciles cash and cash equivalents and restricted cash on the Consolidated Balance Sheets to cash, cash equivalents and restricted cash on the Consolidated Statements of Cash Flows:

	December 31,			
	2018		2017	
	(In millions)			
Cash and cash equivalents	$	8	$	5
Restricted cash		14		14
Cash, cash equivalents and restricted cash shown in the Consolidated Statement of Cash Flows	$	22	$	19

(15) 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.

Transportation and Storage Agreements

Transportation and Storage Agreements with CenterPoint Energy

EGT provides natural gas transportation and storage services to CenterPoint Energy's LDCs in Arkansas, Louisiana, Oklahoma and Northeast Texas under a combination of contracts that include the following types of services: firm transportation, firm transportation with seasonal demand, firm storage, no-notice transportation with storage and maximum rate firm transportation. The contracts for firm transportation with seasonal demand will remain in effect through March 31, 2021. The contracts for firm transportation, firm storage and firm no-notice transportation with storage, as well as the contracts for maximum rate firm transportation for Oklahoma and portions of Northeast Texas, are in effect through March 31, 2021, and will remain in effect thereafter unless and until terminated by either party upon 180 days' prior written notice. The contracts for maximum rate firm transportation for Arkansas, Louisiana and Texarkana, Texas terminated on March 31, 2018. MRT provides firm transportation and firm storage services to CenterPoint Energy's LDCs in Arkansas and Louisiana. Contracts for these services are in effect through May 15, 2023 and will remain in effect unless and until terminated by either party upon twelve months' prior written notice.

The Partnership may agree to reimburse the costs that its customers incur to make required modifications for the repair and maintenance of pipelines that impact customer delivery points. For the year ended December 31, 2018, we reimbursed CenterPoint Energy's LDCs $1 million in connection with receipt facility modifications that were necessitated by the repair and maintenance of our pipelines and in connection with a reimbursement associated with an unplanned pipeline outage. For the year ended December 31, 2017, we reimbursed CenterPoint Energy's LDCs $1 million in connection with receipt facility modifications that were necessitated by the repair and maintenance of our pipelines.

Transportation and Storage Agreement with OGE Energy

EOIT provides no-notice load-following transportation and storage services to OGE Energy. On March 17, 2014, EOIT entered into a transportation agreement with OGE Energy for four of its generating facilities, with a primary term of May 1, 2014 through April 30, 2019. On October 24, 2018, EOIT entered into a no-notice load-following transportation agreement with OGE Energy, with a primary term of April 1, 2019 through May 1, 2024. Following the primary term, the agreement will remain in effect from year to year thereafter unless and until either party provides notice of termination to the other party at least 180 days prior to the commencement of the succeeding annual period. On December 6, 2016, EOIT entered into an additional firm transportation agreement with OGE Energy, for one of its generating facilities with a primary term that began on December 1, 2018 through December 1, 2038.

Gas Sales and Purchases Transactions

The Partnership sells natural gas volumes to affiliates of CenterPoint Energy and OGE Energy or purchases natural gas volumes from affiliates of CenterPoint Energy through a combination of forward, monthly and daily transactions. The Partnership enters into these physical natural gas transactions in the normal course of business based upon relevant market prices.

The Partnership's revenues from affiliated companies accounted for 5%, 5% and 7% of total revenues during the years ended December 31, 2018, 2017 and 2016, respectively. Amounts of total revenues from affiliated companies included in the Partnership's Consolidated Statements of Income are summarized as follows:

	Year Ended December 31,		
	2018	2017	2016
		(In millions)	
Gas transportation and storage service revenue — CenterPoint Energy	$ 111	$ 110	$ 110
Natural gas product sales — CenterPoint Energy	11	6	1
Gas transportation and storage service revenue — OGE Energy	37	35	36
Natural gas product sales — OGE Energy	4	2	12
Total revenues — affiliated companies	$ 163	$ 153	$ 159

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

	Year Ended December 31,		
	2018	2017	2016
		(In millions)	
Cost of natural gas purchases — CenterPoint Energy	$ 3	$ 1	$ —
Cost of natural gas purchases — OGE Energy	23	19	14
Total cost of natural gas purchases — affiliated companies	$ 26	$ 20	$ 14

Corporate services, operating lease expense and seconded employee

The Partnership receives services and support functions from each of CenterPoint Energy and OGE Energy under service agreements for an initial term that ended 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 prior to the end of any extension. 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 2018 are $4 million and $1 million, respectively.

The Partnership leases office and data center space from an affiliate of CenterPoint Energy in Shreveport, Louisiana. The term of the lease was effective on October 1, 2016 and extends through December 31, 2019. As of December 31, 2018, the Partnership expects to incur approximately $1 million in rent and maintenance expenses under the lease during the remaining term of the lease.

During the years ended December 31, 2018, 2017 and 2016, the Partnership had 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 actual cost subject to a cap of $5 million in 2018 and thereafter, unless and until secondment is terminated.

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

	Year Ended December 31,		
	2018	2017	2016
		(In millions)	
Corporate Services — CenterPoint Energy	$ 1	$ 3	$ 6
Operating Lease — CenterPoint Energy	1	1	—
Seconded Employee Costs — OGE Energy	29	31	29
Corporate Services — OGE Energy	1	3	5
Total corporate services, operating lease and seconded employee expense	$ 32	$ 38	$ 40

Series A Preferred Units

On February 18, 2016, the Partnership completed the private placement, with CenterPoint Energy, of 14,520,000 Series A Preferred Units representing limited partner interests in the Partnership for a cash purchase price of $25.00 per Series A Preferred Unit, resulting in proceeds of $362 million, net of issuance costs. See Note 6 for further discussion of the Series A Preferred Units.

(16) Commitments and Contingencies

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,						
	2019	**2020**	**2021**	**2022**	**2023**	**After 2023**	**Total**
				(In millions)			
Noncancellable operating leases	$ 14	$ 3	$ 3	$ 3	$ 3	$ 14	$ 40

Total rental expense for all operating leases was $35 million, $27 million and $27 million during the years ended December 31, 2018, 2017 and 2016, respectively.

The Partnership currently occupies 162,053 square feet of office space at its principle 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. These lease expenses are included in General and administrative expense in the Consolidated Statements of Income.

During 2017, the Partnership entered into a lease to occupy 48,642 square feet of office space in Houston, Texas, which ends December 31, 2025. The lease payments are $4 million over the lease term, as well as a proportionate percentage of facility expenses. These lease expenses are included in General and administrative expense in the Consolidated Statements of Income.

On August 28, 2018, the Partnership entered into the Bank of Oklahoma Park Plaza lease to occupy 154,584 feet of office space in Oklahoma City, Oklahoma, which ends June 30, 2029. The lease payments commence on July 1, 2019, and total $25 million over the lease term, as well as a proportionate percentage of facility expenses. The Partnership will relocate its headquarters to the new location during the third quarter of 2019. Minimum lease payments are expected to be $1 million in 2019 and $2 million per year from 2020 through 2023.

The Partnership currently has 110 compression service agreements, of which 46 agreements are on a month-to-month basis, 60 agreements will expire in 2019 and four agreements 2020. The Partnership also has seven 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 Consolidated Statements of Income.

Commercial Obligations

On January 1, 2017, the Partnership entered into a 10-year gathering and processing agreement, which became effective on July 1, 2018, with an affiliate of Energy Transfer, LP for 400 MMcf/d of deliveries to the Godley Plant in Johnson County, Texas. As of December 31, 2018, the Partnership estimates the remaining associated 10-year minimum volume commitment fee to be $215 million in the aggregate. Minimum volume commitment fees are expected to be $23 million per year from 2019 through 2027 and $11 million in 2028.

On September 13, 2018, the Partnership executed a precedent agreement for the development of the Gulf Run Pipeline, an interstate natural gas transportation project. On January 30, 2019, a final investment decision was made by Golden Pass LNG, the cornerstone shipper for the LNG facility to be served by the Gulf Run Pipeline project. Subject to approval of the project by the FERC, the Partnership will be required to construct a large-diameter pipeline from northern Louisiana to Gulf Coast markets. In addition, the Partnership may transfer existing EGT transportation infrastructure to the Gulf Run Pipeline. Under the precedent agreement, the Partnership estimates the cost to complete the Gulf Run Pipeline project would be as much as $550 million and the project is backed by a 20-year firm transportation service. The Gulf Run Pipeline connects natural gas producing regions in the U.S., including the Haynesville, Marcellus, Utica and Barnett shales and the Mid-Continent region. The project is expected to be placed into service in 2022.

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.

(17) Income Taxes

The Partnership's earnings are generally not 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 non-corporate 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 consolidated financial statements. Consequently, the Consolidated Statements of Income do not include an income tax provision (other than Texas state margin taxes and taxes associated with the Partnership's corporate subsidiary). On December 22, 2017, the act known as the "Tax Cuts and Jobs Act," was signed into law which lowered the corporate tax rate from 35% to 21% for tax years beginning after December 31, 2017. As a result of this new law, the Partnership's corporate subsidiaries re-valued their deferred income tax assets and liabilities as of December 31, 2017, which resulted in recording a federal deferred income tax benefit of $1 million for the year ended December 31, 2017.

The items comprising income tax expense are as follows:

	Year Ended December 31,		
	2018	2017	2016
	(In millions)		
Provision (benefit) for current income taxes			
Federal	$ —	$ 1	$ (1)
State	—	1	—
Total provision (benefit) for current income taxes	—	2	(1)
Provision (benefit) for deferred income taxes, net			
Federal	$ (1)	(2)	$ 3
State	—	(1)	(1)
Total provision (benefit) for deferred income taxes, net	(1)	(3)	2
Total income tax (benefit) expense	$ (1)	$ (1)	$ 1

The components of Deferred Income Taxes as of December 31, 2018 and 2017 were as follows:

	December 31,	
	2018	2017
	(In millions)	
Deferred tax liabilities, net:		
Non-current:		
Intercompany management fee	$ 16	$ 18
Depreciation	5	5
Accrued compensation	(16)	(17)
Total deferred tax liabilities, net	5	6

Uncertain Income Tax Positions

There were no unrecognized tax benefits as of December 31, 2018, 2017 and 2016.

Tax Audits and Settlements

The federal income tax return of the Partnership has been audited through the 2013 tax year.

(18) Equity-Based Compensation

Enable GP has adopted the Enable Midstream Partners, LP Long Term Incentive Plan (LTIP) for officers, directors and employees of the Partnership and its affiliates, including any individual who provides services to the Partnership as a seconded employee. The LTIP provides for the following types of awards: restricted units, phantom units, appreciations rights, option rights, cash incentive awards, performance units, distribution equivalent rights, and other awards denominated in, payable in, valued in or otherwise based on or related to common units.

The LTIP is administered by the Compensation Committee of the Board of Directors. With respect to any grant of equity as long-term incentive awards to our independent directors and our officers subject to reporting under Section 16 of the Exchange Act, the Compensation Committee makes recommendations to the Board of Directors and any such awards will only be effective upon the approval of the Board of Directors. The LTIP limits 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 are available for delivery pursuant to other awards.

The Board of Directors may terminate or amend the long-term incentive plan at any time with respect to any units for which a grant has not yet been made, including amending the long-term incentive plan to increase the number of units that may be granted subject to the requirements of the exchange upon which the common units are listed at that time. However, no change in any outstanding grant may be made that would be adverse to the participant without the consent of the participant.

Performance unit, restricted unit and phantom unit awards are classified as equity on the Partnership's Consolidated Balance Sheet. The following table summarizes the Partnership's equity-based compensation expense for the years ended December 31, 2018, 2017 and 2016 related to performance units, restricted units and phantom units for the Partnership's employees and independent directors:

	Year Ended December 31,		
	2018	2017	2016
		(In millions)	
Performance units	$ 9	$ 10	$ 9
Restricted units	1	2	3
Phantom units	6	3	1
Total equity-based compensation expense	$ 16	$ 15	$ 13

Performance Units

Awards of performance based phantom units (performance units) have been made under the LTIP in 2018, 2017 and 2016 to certain officers and employees providing services to the Partnership. Subject to the achievement of performance goals, the performance unit awards cliff vest three years from the grant date, with distribution equivalent rights paid at vesting. The performance goals for 2018, 2017 and 2016 awards are based on total unitholder return over a three-calendar year performance cycle. Total unitholder return is based on the relative performance of the Partnership's common units against a peer group. The performance unit awards have a payout from zero to 200% of the target based on the level of achievement of the performance goal. Performance unit awards are paid out in common units, with distribution equivalent rights paid in cash at vesting. Any unearned performance units are cancelled. Pay out requires the confirmation of the achievement of the performance level by the Compensation Committee. Prior to vesting, performance units are subject to forfeiture if the recipient's employment with the Partnership is terminated for any reason other than death, disability, retirement or termination other than for cause within two years of a change in control. In the event of retirement, a participant will receive a prorated payment based on the target performance, rather than actual performance, of the performance goals during the award cycle.

The fair value of each performance unit award was estimated on the grant date using a lattice-based valuation model. The valuation information factored into the model includes 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. Equity-based compensation expense for each performance unit award 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 included in the fair value calculation of the performance unit award. The expected price volatility for the awards granted in 2018 and 2017 is based on three years of daily stock price observations, to determine the total unitholder return ranking. The expected price volatility for the awards granted in 2016 is based on two years of daily stock price observations, combined with the average of the one-year volatility of the applicable 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. 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.

	2018	2017	2016
Number of units granted	551,742	468,626	1,235,429
Fair value of units granted	$ 17.70	$ 19.27	$10.42 - $27.77
Expected price volatility	44.2%	47.3%	43.2% - 46.0%
Risk-free interest rate	2.36%	1.57%	0.86% - 0.90%
Distribution yield	8.56%	9.10%	10.70% - 12.10%
Expected life of units (in years)	3	3	3

Phantom Units

Awards of phantom units have been made under the LTIP in 2018, 2017 and 2016 to certain officers and employees providing services to the Partnership and certain directors of Enable GP. Phantom units vest on the first, second or third anniversary of the grant date with distribution equivalent rights paid during the vesting period. Phantom unit awards are paid out in common units, with distributions equivalent rights paid in cash. Phantom units cliff-vest at the end of the vesting period. Any unearned phantom units are cancelled. Prior to vesting, phantom units are subject to forfeiture if the recipient's employment with the Partnership is terminated for any reason other than death, disability, retirement or termination other than for cause within two years of a change in control.

The fair value of the phantom units was based on the closing market price of the Partnership's common unit on the grant date. Equity-based 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 the vesting period. Distributions on phantom units are paid during the vesting period and, therefore, are included in the fair value calculation. The expected life of the phantom unit is based on the applicable vesting period. The number of phantom units granted and the grant date fair value are shown in the following table.

	2018	2017	2016
Phantom units granted	546,708	392,338	653,286
Fair value of phantom units granted	$13.74 - $17.00	$15.44 - $16.93	$8.12 - $15.30

Other Awards

In 2018, 2017 and 2016, the Board of Directors granted 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.

	2018	2017	2016
Common units granted	16,335	16,653	14,914
Fair value of common units granted	$ 14.94	$ 15.03	$ 15.35

Units Outstanding

A summary of the activity for the Partnership's performance units, restricted units and phantom units as of December 31, 2018 and changes during 2018 are shown in the following table.

	Performance Units		Restricted Stock		Phantom Units	
	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 12/31/2017	2,040,407	$ 13.86	222,434	$ 17.87	987,380	$ 11.38
Granted [(1)]	551,742	17.70	—	—	546,708	14.23
Vested [(2)(3)]	(401,772)	16.59	(221,068)	17.87	(25,287)	13.80
Forfeited	(80,542)	14.30	(1,366)	16.75	(61,211)	12.39
Units outstanding at 12/31/2018	2,109,835	14.33	—	—	1,447,590	12.38
Aggregate intrinsic value of units outstanding at December 31, 2018	$ 29		$ —		$ 20	

(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.

(2) Performance units vested as of December 31, 2018 include 401,772 units from the annual grant, which were approved by the Board of Directors in 2015 and paid out at 200% of target, or 803,544 units, based on the level of achievement of a performance goal established by the Board of Directors over the performance period.

(3) Performance units outstanding as of December 31, 2018 include 1,109,676 units from the 2016 annual grant, which were approved by the Board of Directors in 2016. The results of the performance units were certified by the Compensation Committee in February 2019, at a 200% payout based on the level of achievement of a performance goal established by the Board of Directors over a performance period of January 1, 2016 through December 31, 2018. The increase in outstanding units for a payout percentage of an amount other than 100% is not reflected above until the vesting date.

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) for each of the years ended December 31, 2018, 2017 and 2016 are shown in the following tables.

	Year Ended December 31, 2018		
	Performance Units	Restricted Stock	Phantom Units
		(In millions)	
Aggregate intrinsic value of units vested	$ 11	$ 3	$ 1
Fair value of units vested	7	4	—

	Year Ended December 31, 2017		
	Performance Units	Restricted Stock	Phantom Units
		(In millions)	
Aggregate intrinsic value of units vested	$ 5	$ 2	$ —
Fair value of units vested	10	4	—

	Year Ended December 31, 2016		
	Performance Units	Restricted Stock	Phantom Units
		(In millions)	
Aggregate intrinsic value of units vested	$ —	$ 1	$ —
Fair value of units vested	—	3	—

Unrecognized Compensation Expense

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

	December 31, 2018	
	Unrecognized Compensation Cost (In millions)	Weighted Average to be Recognized (In years)
Performance Units	$ 11	0.92
Restricted Units	—	0.00
Phantom Units	8	1.15
Total	$ 19	

As of December 31, 2018, there were 7,555,026 units available for issuance under the long-term incentive plan.

(19) 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. 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 and (ii) transportation and storage. The gathering and processing segment primarily provides natural gas and crude oil gathering and natural gas processing services to our producer customers. The transportation and storage segment provides interstate and intrastate natural gas pipeline transportation and storage services primarily to our producer, power plant, LDC and industrial end-user customers.

Financial data for reportable segments are as follows:

Year Ended December 31, 2018	Gathering and Processing	Transportation and Storage [(1)]	Eliminations	Total
		(In millions)		
Product sales	$ 2,016	$ 625	$ (535)	$ 2,106
Service revenue	802	537	(14)	1,325
Total Revenues [(2)]	2,818	1,162	(549)	3,431
Cost of natural gas and natural gas liquids, excluding depreciation and amortization shown separately	1,741	628	(550)	1,819
Operation and maintenance, General and administrative	312	189	—	501
Depreciation and amortization	263	135	—	398
Taxes other than income tax	38	27	—	65
Operating Income	$ 464	$ 183	$ 1	$ 648
Total Assets	$ 9,874	$ 5,805	$ (3,235)	$ 12,444
Capital expenditures, including acquisitions	$ 981	$ 190	$ —	$ 1,171

Year Ended December 31, 2017	Gathering and Processing	Transportation and Storage (1)	Eliminations	Total
	(In millions)			
Product sales	$ 1,538	$ 621	$ (506)	$ 1,653
Service revenue	632	525	(7)	1,150
Total Revenues (2)	2,170	1,146	(513)	2,803
Cost of natural gas and natural gas liquids, excluding depreciation and amortization shown separately	1,285	604	(508)	1,381
Operation and maintenance, General and administrative	289	179	(4)	464
Depreciation and amortization	232	134	—	366
Impairments	—	—	—	—
Taxes other than income tax	37	27	—	64
Operating Income	$ 327	$ 202	$ (1)	$ 528
Total Assets	$ 9,079	$ 5,616	$ (3,102)	$ 11,593
Capital expenditures, including acquisitions	$ 601	$ 113	$ —	$ 714

Year Ended December 31, 2016	Gathering and Processing	Transportation and Storage (1)	Eliminations	Total
	(In millions)			
Product sales	$ 1,081	$ 479	$ (388)	$ 1,172
Service revenue	559	545	(4)	1,100
Total Revenues (2)	1,640	1,024	(392)	2,272
Cost of natural gas and natural gas liquids, excluding depreciation and amortization shown separately	915	492	(390)	1,017
Operation and maintenance, General and administrative	276	191	(2)	465
Depreciation and amortization	212	126	—	338
Impairments	9	—	—	9
Taxes other than income tax	32	26	—	58
Operating Income	$ 196	$ 189	$ —	$ 385
Total Assets	$ 7,453	$ 4,963	$ (1,204)	$ 11,212
Capital expenditures	$ 312	$ 71	$ —	$ 383

(1) Equity in earnings of equity method affiliate is included in Other Income (Expense) on the Consolidated Statements of Income and is not included in the table above. See Note 10 for discussion regarding ownership interest in SESH and related equity earnings included in the transportation and storage segment for the years ended December 31, 2018, 2017 and 2016.

(2) The Partnership had no external customers accounting for 10% or more of Total revenues in periods shown. See Note 15 for revenues from affiliated companies.

(20) Quarterly Financial Data (Unaudited)

Summarized unaudited quarterly financial data for 2018 and 2017 are as follows:

	Quarters Ended			
	March 31, 2018	June 30, 2018	September 30, 2018	December 31, 2018
	(in millions, except per unit data)			
Total Revenues	$ 748	$ 805	$ 928	$ 950
Cost of natural gas and natural gas liquids	375	444	516	484
Operating income	139	126	171	212
Net income	114	95	139	175
Net income attributable to limited partners	114	95	138	174
Net income attributable to common and subordinated units	105	86	129	165
Basic earnings per unit				
Common units	$ 0.24	$ 0.20	$ 0.30	$ 0.38
Subordinated units (1)	$ —	$ —	$ —	$ —
Diluted earnings per unit				
Common units	$ 0.24	$ 0.20	$ 0.30	$ 0.38
Subordinated units	$ —	$ —	$ —	$ —

	Quarters Ended			
	March 31, 2017	June 30, 2017	September 30, 2017	December 31, 2017
	(in millions, except per unit data)			
Total Revenues	$ 666	$ 626	$ 705	$ 806
Cost of natural gas and natural gas liquids	308	279	349	445
Operating income	140	122	137	129
Net income	120	96	113	108
Net income attributable to limited partners	120	95	113	108
Net income attributable to common and subordinated units	111	86	104	99
Basic earnings per unit				
Common Units	$ 0.26	$ 0.20	$ 0.24	$ 0.23
Subordinated units	$ 0.25	$ 0.20	$ 0.24	$ —
Diluted earnings per unit				
Common Units	$ 0.26	$ 0.20	$ 0.24	$ 0.23
Subordinated units (1)	$ 0.25	$ 0.20	$ 0.24	$ —

(1) See Note 6 for discussion of the conversion of the subordinated units.

(21) Subsequent Event

On January 29, 2019, the Partnership entered into a term loan facility, providing for an unsecured three-year $1 billion term loan agreement. As of January 31, 2019, there is a principal advance of $200 million outstanding under the 2019 Term Loan Agreement, and a delayed-draw feature permits the Partnership to borrow up to an additional $800 million within 180 days of the closing date, subject to the terms and conditions of the 2019 Term Loan Agreement. The 2019 Term Loan Agreement provides that outstanding borrowings bear interest at the eurodollar rate and/or an alternate base rate, at the Partnership's election, plus an applicable margin. The applicable margin is based on the Partnership's designated ratings from Standard & Poor's Rating Services, Moody’s Investor Services and Fitch Ratings. As of January 31, 2019, the applicable margin for LIBOR-based advances under the 2019 Term Loan Facility was 1.25% based on the Partnership’s credit ratings. The 2019 Term Loan Agreement contains substantially the same covenants as the Revolving Credit Facility.

The 2019 Term Loan Agreement requires the Partnership to, starting April 29, 2019 and continuing until the date on which all commitments have expired or been terminated or the amount available to be drawn is zero, pay a ticking fee on each lender’s unused commitment amount. The ticking fee shall equal 0.125% on the actual daily amount of such lender’s portion of the unused commitments.

Advances under the 2019 Term Loan Agreement are subject to certain conditions precedent, including the accuracy in all material respects of certain representations and warranties and the absence of any default or event of default. Advances under the 2019 Term Loan Agreement may be used to refinance indebtedness outstanding from time to time and for other general corporate purposes, including to fund acquisitions, investments and capital expenditures. Advances under the 2019 Term Loan Agreement can be prepaid, in whole or in part, at any time without premium or penalty, other than usual and customary LIBOR breakage costs, if applicable.

The 2019 Term Loan Agreement contains a financial covenant requiring the Partnership to maintain a ratio of consolidated funded debt to consolidated EBITDA as of the last day of each fiscal quarter of less than or equal to 5.00 to 1.00; provided that, for a certain period time following an acquisition by the Partnership or certain of its subsidiaries with a purchase price that when combined with the aggregate purchase price for all other such acquisitions in any rolling 12-month period, is equal to or greater than $25 million, 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 2019 Term Loan Agreement also contains covenant s that restrict the Partnership and certain of its subsidiaries in respect of, amoung other things, mergers and consolidations, sales of all or substantially all assets, incurrenece of subisdary indebtedness, incurrence of liens, transactions with affiliates, designation of subsidiaries as Excluded Subsidiaries (as defined in the 2019 Term Loan Agreement), restricted payments, changes in the nature of their respective business and entering into certain restrictive agreements. The 2019 Term Loan Agreement is subject to acceleration upon the occurrence of certain defaults, including, amoung 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 judgements in excess of $100 million, and the occurrence of certain ERISA and bankruptcy events, subject where applicable to specified cure periods.